COUNCIL STAFF REPORT

CITY COUNCIL *of* SALT LAKE CITY

Item Schedule:
Briefing: April 23, 2019
Public Hearing:
Potential Action:

TO: City Council Members

FROM: Sam Owen, Policy Analyst

DATE: April 23, 2019

RE: FISCAL YEAR 2019-20 BUDGET,
DEPARTMENT OF PUBLIC UTILITIES,
Water, Sewer, Stormwater, and Street Lighting Funds

ISSUE AT-A-GLANCE

The Mayor's Recommended Budget for the Department of Public Utilities includes the Water, Sewer, Stormwater, and Street Lighting Enterprise Funds, totaling $298,017,775 for capital and operating expenses for the fiscal year 2020. Major budget items include system upgrades and expansions in response to aging infrastructure and new regulatory requirements, and 17 new staff positions related to the significant capital projects scheduled over the coming years.

These four Utilities are Enterprise Funds, operating more or less like businesses separate from the General Fund. Each fund generates revenue through user fees and has separate staff, materials and supply budgets and capital improvement programs. The management and administration of the four funds is all under the Department of Public Utilities.

SUPPLEMENTAL COMPONENTS

The Department also transmitted a proposed resolution that, if approved, would convey the Council's support for the new water reclamation facility (WRF). The resolution contains information about the project's budget as well. The resolution is required by the Utah Department of Environmental Quality (UDEQ) as a condition on its granting a regulatory variance for the current reclamation facility. The variance is required because regulatory compliance will only be achieved once the new plant is operational, by 2025. This item is Attachment 2.

Another proposal before the Council is the ordinance that would adopt a new rate structure for the Water, Sewer and Stormwater Utilities. The Council was briefed on the new proposed rate structure October 2, 2018. More information on this item is found beginning page 3 of this report. Attachments 3 and 4 pertain to this item.

The Department also provided a final copy of its Renewable Energy Plan, which outlines goals and methods for carbon reduction across the Utilities. See Attachment 5. It is Council staff understanding that preparation of this kind of carbon mitigation/reduction planning was a major component of this year's Citywide budget proposal process.

Attachments
Attachment 1, Public Utilities proposed budget
Attachment 2, Water reclamation facility resolution of support
Attachment 3, Rate structure ordinance
Attachment 4, October 2018 Council rate study briefing
Attachment 5, Public Utilities renewable energy plan

Some of the other major items in this budget document include:

- **Rate increases:** 18 percent this year in the Sewer Utility, 10 percent in the Water Utility, and 10 percent in the Stormwater Utility. See more about these increases, beginning page 3. The increases are connected in part with the need to pay debt service for bonds issued to fund significant capital improvements over the next several years. The total impact to the average household utility bill would be approximately $5.34 per month.
- **Capital projects**: capital improvements planned for this year total $172,094,600. Notably, the Sewer Utility anticipates costs for the new Water Reclamation Facility (WRF) approaching $528,130,000. The Department has applied for federal funding through the Water Infrastructure Financing Innovation Act (WIFIA), which may result in favorable loans covering up to 49% of the cost of the new WRF. Furthermore, anticipated sewer collection system capacity upgrades are budgeted for $36,630,500 during fiscal 2020; $39,132,179 is projected in terms of actual expenditures on these projects during fiscal 2019. Over $100 million is budgeted for similar projects over the subsequent four fiscal years. These are Public Utilities Master Plan projects and not infrastructure projects directly caused by new development in the City's northwest quadrant, although the timelines have been adjusted for some Master Plan collection system projects based on new construction. See more about these upgrades below.
- **Personnel-related increases**: Personal Services will increase over fiscal 2019 by $2,505,057, which includes 17 total new full-time equivalents (FTEs), a 3 percent cost-of-living adjustment (COLA), and contemplates a 7 percent increase in insurance for medical premiums. The new employees are necessary to manage capital projects, increased operational needs, and to provide for succession of key positions. COLA adjustments are included in the proposed budget as a placeholder since Enterprise Fund budgets are reviewed by separate Advisory Boards, but will be adjusted based on the salary adjustment ultimately approved for City employees.

POLICY QUESTIONS

1. Northwest Quadrant- The Council may wish to ask the following questions in order to gain a more comprehensive understanding of the Utility projects in the Northwest Quadrant.
    a. Reports from the Administration, as available, on the status of the betterments to infrastructure improvements in the Northwest Quadrant as the State Prison construction proceeds. Per the contract between the City and State, monthly reports will be generated on the status and expense of betterments—the Council may wish to receive these reports or to otherwise request information about the progress of betterments and related costs as the process unfolds.
    b. Information of how costs the City will incur in construction of betterments on infrastructure improvements related to construction of the Prison will be recouped, so existing ratepayers are not unduly burdened. For example, where new private development in the Northwest Quadrant "taps into" or benefits from implementation of these betterments, would fees be assessed attendant to the improved capacity or service to help offset the costs over longer periods of time? This might be assessed through the application of impact fees, or through other means.
    c. Which Master Plan projects have been or will be expedited, in response to increased demands for service related to new development in the Northwest Quadrant. This would help with a more

comprehensive understanding of how new development in the Northwest Quadrant could be impacting existing customers through changes in rates for services.

2. The Council may wish for a more detailed explanation of impact fees and how they are being collected and applied within the Utility. At the time of this writing, 13 Master Plan projects budgeted for implementation during the coming fiscal year are expected to be eligible for impact fees; however, this has not yet been confirmed. Council Members may wish to request follow-up and ongoing status reports with regard to the Utilities' implantation of impact fees, especially in the context of a pending, new Impact Fees Facilities Report from the Department.
3. Community members in different parts of the City have asked about the Street Lighting Utility's replacement of older lights with LED technologies emitting light in "cooler" color spectrums, resulting in "bluer" light that some experience as appearing with higher intensity. Community members have pointed to efforts by other municipalities and admonitions from particular research items to move away from these "bluer" lights to adopt "warmer" lighting. Subsequent conversations with the Council have indicated energy-efficiency was to be an ongoing and forefront consideration in replacing Street Lighting. The existing Plan does not contemplate LED technology because it had not been developed at the time of the Plan's adoption.
    a. Council Members may also wish for an update on the Street Lighting Master Plan update, for which public engagement has commenced.
    b. The Council may wish to request more information about how and when constituent feedback has been incorporated in the process of replacements, both in terms of how lights are directed and how intensity is assessed and implemented.
    c. Council Members may wish to request that the Utility continue to look into how impact fees may or may not be applicable to Street Lighting projects, now or in the future.

MAJOR ITEM DETAIL

The percentages of proposed rate increases are calculated on the basis of a new proposed rate structure for the three utilities proposing increases (Water, Sewer, Stormwater). The new proposed rate structure was presented to the Council October 2, 2018. In conjunction with the current budget, the Department proposes implementation of that rate schedule. Attachment 4 provides detailed background on the rate structure. The rate structure change itself is revenue neutral. Attachment 3 is a proposed ordinance that would adopt the new rate structure. Information on the percentage changes for the proposed rate increases *without* adoption of the new rate structure is contained in Appendix D of the Administration's Public Utilities budget proposal.

Increases in rates for the current fiscal year, as well as the years subsequent, are in response to the bonding requirements and related debt service necessary to fund the replacement, maintenance and upgrades of aging and in some cases badly deteriorated infrastructure. The replacement, maintenance and upgrades of existing infrastructure will facilitate the ongoing use and availability of the Utilities' services for current customers.

- **Water Utility**

  In conjunction with implementation of the new rate structure, the proposed rate increase of 5 percent would impact an average resident's monthly bill by reducing it about 19 cents (little to no impact). Rates are projected to increase 5 percent each year through fiscal year 2022-23. Increases are timed based on capital project needs and the related bonding to finance the projects; as part of this, rates also increased 4 percent last fiscal year. The Utility anticipates bond proceeds of $35,196,000 and $44,490,000, in the fiscal years 2020 and 2021, respectively.

- **Sewer Utility**

  In conjunction with implementation of the new rate structure, the proposed rate increase of 18 percent would impact an average resident's bill by about $5.04 each month. Rates are projected to increase 18 percent for the subsequent two fiscal years, 15 percent for fiscal 2023 and 10 percent for fiscal 2024. Increases are timed based on capital project needs and the related bonding to finance the projects; as part of this, rates also increased 30 percent last fiscal year. The Utility anticipates bond proceeds of $55,307,000 and $39,218,000 in the fiscal years 2020 and 2021 respectively. (Projected rate increases

will continue to be evaluated with each year's budget and capital project schedule, and may change as needed.)

- **Stormwater Utility**
  In conjunction with implementation of the new rate structure, the proposed rate increase of 10 percent would impact an average resident's bill by about $0.49 each month. Dwindling cash reserves, stronger regulatory requirements, and infrastructure needs are drivers for the proposed rate increase. Additional rate increases of 10 percent, 9 percent, 6 percent and 5 percent are anticipated for the four subsequent fiscal years, respectively. The Utility anticipates bond proceeds of $14.5 million in fiscal 2020, in part to fund recently-initiated flooding mitigation projects and projects implemented in relation to road work funded by the recent general obligation bond.

- **Street Lighting Utility**
  This fund will not have a rate increase this year. The Utility reports energy savings related to LED lighting upgrades of about $300,000 from the current fiscal year, and anticipates similar outcomes in future years.

Capital projects:
Improvements planned in the Water Utility have to do with strengthening service capacity and updates to aging, critical infrastructure. Some items of note:

- Treatment Plant projects
  - Upgrades at the City Creek Water Treatment Plant are budgeted for $1,500,000 this year, reflecting necessary upgrades to critical infrastructure for the treatment and conveyance of drinking water. Improvements will total an estimated $1.5 million for the four subsequent years. Phase 2 of the City Creek Plant upgrades is budgeted for an estimated $30,000,000; that expense is not planned to begin before fiscal year 2024.
  - The Parley's Water Treatment Plant will undergo improvements this year totaling an estimated $2,050,000. The subsequent fiscal year 2021 budgets for $11,250,000 in capital costs for the plant and $2,000,000 in capital costs for each additional year through fiscal 2024. The Department estimates delayed capital costs at $158,000,000, of which $136,500,000 is designated for a new Parley's Water Treatment Plant. The remainder of those delayed capital costs relates to other projects at the facility. The delayed capital expenditures are costs that the Utility anticipates as being necessary, but hasn't planned to implement in terms of the projections in the fiscal year 2020 budget proposal.
  - The Big Cottonwood Canyon Treatment Plant will undergo improvements budgeted for $4,300,000, including $2,500,000 for a number of projects related to a plant rebuild. The plant rebuild is expected to incur further costs of $5,000,000 in the subsequent fiscal year 2021 and at least $2,000,000 annually through fiscal 2024. The Department estimates an additional $156,750,000 in delayed capital costs for this specific facility in the future. The delayed capital expenditures are costs that the Utility anticipates as being necessary, but hasn't planned to implement in terms of the projections in the fiscal year 2020 budget proposal.
- Improvements and electrical system upgrades at the 4th Avenue well near Canyon Road this year is budgeted for $3,000,000; rehabilitation of the Mountain Dell Dam for $2,165,000; and the hydropower project in Parley's Canyon budgeted for another $100,000 after last year's expenditure of $1,000,054.
- A water line on 1300 East Street ran $2,417,418 last year, and energy efficiency and renewable energy capital improvements are budgeted for another $200,000 (existing in-pipe turbines are scheduled to begin generating renewable power in 2021).
- The East-West aqueduct or water conveyance line from Park Reservoir to near Sugar House Park is budgeted for $10,000,000 this year and $10,000,000 in the subsequent year. The line is expected to expand capacity for service to the City's Northwest Quadrant (NWQ), and to provide capacity and redundancy for service elsewhere across the valley as well.

- Water meter replacements are estimated to cost $3,100,000 this year and will begin to allow meters to be read remotely. The meter replacement program is budgeted for $3,100,000 in years subsequent (through 2022-23). Upgrades are expected to reduce costs of meter reading and allow customers to access water consumption information in real time, thus supporting water conservation programs and enabling customers to identify property-side leakages promptly.

Improvements planned in the Sewer Utility have to do with updates and replacements to aging infrastructure, as well as expansions to service capacity. Some items of note:

- Approximately $6,380,000 in maintenance to the existing Water Reclamation Facility (WRF), along with $54,700,000 budgeted for initial construction and design related to the new WRF. As noted above, a total cost estimate for the new facility's construction approaches $528,130,000. The facility's construction is currently expected to be complete and operational in 2024 in order to meet a 2025 deadline based on federal and state nutrient discharge regulatory requirements. Issue periods of bonds used to fund the new construction are timed to coincide with the life of the WRF; payments on the bonds are timed to coincide with the customers who will most benefit during this 30-year period.
- Master Plan implementation of sanitary sewer system upgrades and expansions are budgeted for a combined total of $17,850,000 in the fiscal year 2020, and are budgeted for $19,500,000 and $17,000,000 in the two subsequent fiscal years, respectively. These projects will provide for needed capacity in areas where capacity is already an issue, particularly on the fast-growing west side of the City.
- Ongoing remediation for the Northwest Oil Drain Canal near the WRF will incur estimated costs of $150,000 (the budgeted $300,000 for last year was not spent) in the Sewer Utility.

The following are some items of note planned as part of the Stormwater Utility's capital improvements program for the fiscal year 2018-19.

- Collection mains upgrades on 1700 South from 2100 East to its intersection with Emigration Creek are budgeted for $1,100,000 in fiscal 2020 and another $1,100,000 in the following fiscal year. This is to address stormwater capacity on 1700 South during intense runoff, such as the summer rain events experienced in 2017. $211,811 had been expended for this project during fiscal 2019 at the time of the proposed budget's preparation.
- Updates to stormwater-related infrastructure on Gladiola Street from 500 South to 900 South will total an estimated $869,550; updates to storm drain infrastructure along 1300 East are budgeted for an estimated $1,200,00o during fiscal 2020; expenditures on the stormwater portion of this project during fiscal 2019 totaled $377,165.
- Water quality and riparian corridor improvements related to updates at the Stormwater Utility's 1000 North Lift Station are budgeted for $1,700,000; $88,652 was expended during fiscal 2019. This is a projected budget increase of about $700,000 for the project.
- Contributions by developers related to local area projects in the Stormwater Utility are expected to total $400,000. These can be in the form of property or other assets, as well.
- An update to the Drainage Master Plan is budgeted for $700,000. The existing Plan was completed in 1993 and outlines a number of upgrades to the Utility's infrastructure that have taken place since. A new look at the Plan will involve changing climate conditions and green infrastructure.

The Street Lighting Utility will:

- implement a program to provide matching grants for residents interested in certain kinds of privately-maintained lights. The grant is funded by an annual transfer of $20,000 from the General Fund.
- Other capital improvements in the Street Lighting Utility for the fiscal year 2020 are budgeted for $1,725,000 (down from an estimated $2,605,000 last year).
- 8,398 of the 15,662 lights the City maintains are now considered to be energy efficient; Street Lighting is in the seventh year of a ten-year plan to convert all the lights to "high energy efficiency lamps."
- Furthermore, $90,000 is budgeted for the ongoing Street Lighting Master Plan update this year.

Personnel-related increases:
The Department of Public Utilities has historically been conservative with personnel additions; for example, staff adjustments for a sample previous three fiscal years totaled 2 seasonal watershed-related additions, 2 new positions for sewer collection, and one new accountant position.

Proposed staff adjustments will allow the Utilities to manage capital projects, account for increased operational and regulatory needs, and provide succession for key positions. This year's additions total 17 new FTEs, expected to be distributed across the Utilities as follows (charts on next page).

Proposed Personnel Adjustments FY 2019- 2020

Administration	Water	Sewer	Stormwater	Street Lighting	Total
Engineering Technician I	-	-	-	1.00	1.00
Records Technician	0.80	0.10	0.10	-	1.00
Engineer II	0.50	0.25	0.25	-	1.00
Community & Engagement Coordinator	0.50	0.40	0.10	-	1.00
Sustainability Program Manager	1.00	-	-	-	1.00
					5.00
Water Reclamation Facility					
Pretreatment Inspector/Permit Writer		1.00			1.00
Pretreatment Senior Sampler/Inspector		1.00			1.00
FOG/Sewer Rate Program Supervisor		1.00			1.00
Office Technician II		1.00			1.00
					4.00
Maintenance					
Senior Water System Maintenance Worker	1.00				1.00
					1.00
GIS					
GIS Leak Detector II	0.50	0.30	0.20		1.00
					1.00
Engineering					
Engineering Technician II	1.00	0.50	0.50		2.00
Engineering Technician III	0.50	0.25	0.25		1.00
Engineer III	1.00	0.50	0.50		2.00
					5.00
Seasonal Positions					
Watershed Worker (2)	1.00				1.00
					1.00
Total New FTEs	**7.80**	**6.30**	**1.90**	**1.00**	**17.00**

Proposed Personnel Adjustments FY 2018/19

NEW JOBS REQUESTED FOR FY 18/19	Total FTEs	WATER	SEWER	STORM WATER	STREET LIGHTING
Prior Year 2018 Beginning Balance	408.50	262.53	112.43	31.12	2.42
1) PROJECT CONTROL SPECIALIST	1.00	0.50	0.38	0.10	0.02
2) DOCUMENT CONTROLS SPECIALIST	1.00	0.50	0.38	0.10	0.02
3) ENGINEERING TECHNICIAN III	1.00	0.50	0.38	0.10	0.02
4) ENGINNERING TECHNICIAN III	1.00	0.50	0.38	0.10	0.02
5) WATER RIGHTS ASSISTANT	1.00	0.50	0.25	0.25	
6) WATERSHED RANGER	1.00	1.00			
7) WATER PLANT OPERATOR II	1.00	1.00			
8) STORMWATER COMPLIANCE SPECIALIST	1.00			1.00	
9) STORMWATER TECHNICIAN	1.00			1.00	
10) PRETREATMENT INSPEC / PERMIT WRITER	1.00		1.00		
11) SENIOR WATER SYSTEM MAINTENANCE LEAD	1.00	1.00			
12) WATER SYSTEM MAINTENANCE OPERATOR II	1.00	1.00			
13) WATER SYSTEM MAINTENANCE OPERATOR I	1.00	1.00			
14) OFFICE FACILITATOR I - SHOPS PAYROLL (REPLACING VACATED BY HR)	1.00	0.74	0.18	0.08	
TOTAL NEW FTE'S	14.00	8.24	2.95	2.73	0.08
CHANGES DUE TO PAY REDISTRIBUTION:	1.00	2.00	0.05	-1.05	-1.00
TOTAL CHANGES TO FTE'S	14.00	10.24	3.00	1.68	-0.92
	33				
Projected Agency Total FTEs for 2019	422.50	272.77	115.43	32.80	1.50

OTHER BACKGROUND

Role of Impact Fees in upcoming major capital projects:
Related to this discussion of infrastructure improvements and betterments is the concept of impact fees. Impact fees are assessed and paid to the municipality by developing entities. They in turn go to pay for only the expansion, or "growth" component of what is required to provide a level of service, without going to pay for improving or otherwise modifying the existing level of service.

- In the Water Reclamation Facility (WRF):
  Impact fees cannot be used to help entities like the City's Sewer Utility meet regulatory requirements. They cannot be used to pay for maintenance and operations of existing services, either. For example, the City's construction of a new WRF is not expected to expand the current level of service, but is necessary to meet updated regulatory requirements and to replace aging and deteriorated infrastructure. The old plant is not operating at or beyond capacity, so the new plant is not a response to a need to expand capacity; the new plant is thus not considered eligible for funding through impact fees. However, the new plant is being constructed in such a way that expansions could be integrated. If these expansions of the facility were implemented to respond to an increased need for service capacity, construction of the expansions could be eligible for funding through impact fees at some time in the future. This is being more carefully evaluated in the Department's updated Impact Fee Facilities Plan (IFFP).

  In addition to the Sewer Utility, the Water Utility has many such related expenses budgeted for the fiscal year 2020. The need for these capital improvements results from the need to update and replace aging infrastructure, and where this is the only impetus for the improvements, the projects will not be eligible for funding through impact fees. However, some conveyance projects such as the east-west aqueduct funded for a total $20 million in fiscal years 2020 and 2021 are expected to be eligible for impact fees because of directly accommodating an expanded need for service, especially with regard to new development in the Northwest Quadrant. The updated IFFP will identify the portion of Water Utility projects that are reasonably apportioned to growth.

  Capital improvements aside from the WRF in the Sewer Utility deal mostly with collection line system and capacity improvements on the City's west-side, near the site of the current and future WRF. The Department of Public Utilities staff reports these Master Plan collection line system improvements are necessary to maintain the existing level of service and are in response to anticipated deterioration, again commensurate with aging infrastructure. Some of these projects will also increase capacity to accommodate growth. Where some of these projects are being placed on an accelerated timeline, funding such as the State no-interest loan, has been applied to ease the burden for ratepayers. Again, where maintenance or new regulation would be the only impetus for the projects, impact fees do not apply. However, some of the upgrades are expected to be eligible for funding through impact fees; specifics as to which in particular are pending at the time of this writing and will be incorporated in the Department's work updating the IFFP.

- In the new State Prison:
  Commensurate with the impact fee model, developing entities are expected to pay the City's Utilities for connections. For example, when a new apartment building is constructed, the developing entity would need to compensate the City at a certain predetermined rate for the number of Utilities-related facilities the development would provide (faucets, toilets, drains). However, the State as the developing entity responsible for implementation of the new Prison is not understood to be liable for providing these fees for connection. This is another aspect of how the State's arrangement with the municipality is different from other situations.

Department of Public Utilities responses to Council staff email questions, April 2019

Service Level

There are no reductions in service for Public Utilities. In fact, service level is increasing for each of the utilities due to a number of factors, including:

1) Growth throughout the service area causing the need for increased development review, inspections, and engineering

2) The need to address aging water and sewer infrastructure

3) Additional regulatory requirements related to drinking water, stormwater, and sewer

4) The need for updated long term plans for each of the four utilities due to growth, climate change, and public values

5) The need for increased public engagement as we address the above issues

Changes in Programs or Projects from Last Year

Programming and project work continues at a similar level compared to the last fiscal year. There are some increases in programming and projects, including:

1) Design and construction of the new sewer treatment plant

2) Continued capital asset planning for critical infrastructure

3) Increases in stormwater programming and standard operating procedures as a result of managing the City's overall stormwater permit with UDEQ, and as a result of an audit conducted by UDEQ and USEPA in 2016

4) Development of a Fats Oils and Grease (FOG) program for the sewer utility

5) New state reporting requirements related to water use, water rights, and water source sizing

6) New vulnerability and emergency management requirements pursuant to the America's Water Infrastructure Act (passed October 2018)

7) New federal and state requirements anticipated this year regarding emerging contaminants

8) Expedited sewer, water, and stormwater pipe replacements to support the City's general obligation bond for roadway reconstruction

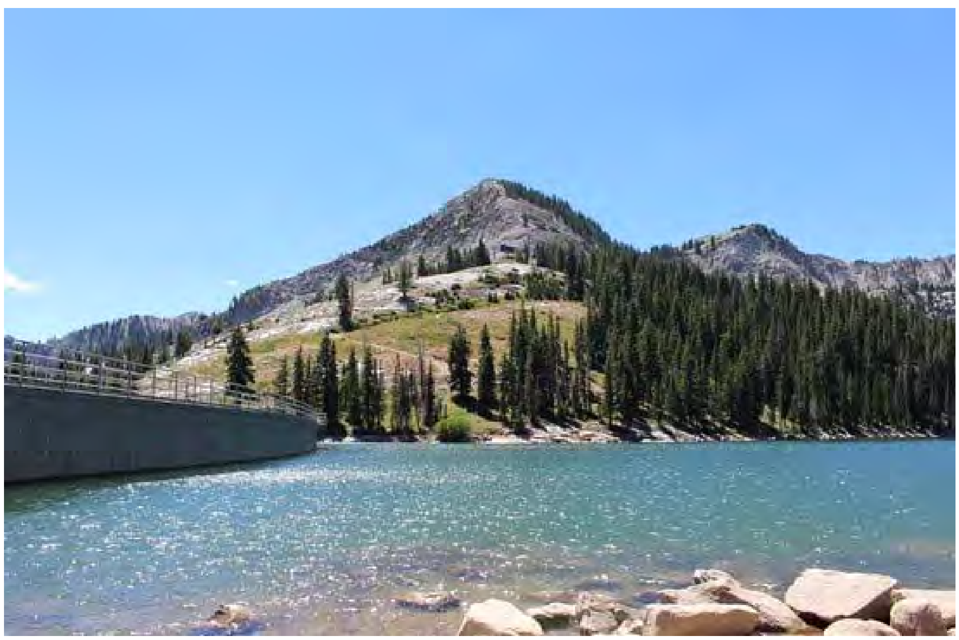
Vacant Positions

As of April 3, 2019, Public Utilities had a total of 24 vacant positions out of 422 positions. Of this total, the Water Utility has 16.5 FTE's, Sewer 6.5 FTE's, and Stormwater 1.0 FTE. The department intends to fill all vacancies, and the hiring process is ongoing.

Carbon Reductions

The Public Utilities budget for FY20 includes an appendix regarding the department's energy management and greenhouse gas mitigation projects. (See Appendix C of proposed budget document and Attachment 5).

PUBLIC UTILTIES ANNUAL
2019-20 FISCAL BUDGET PROPOSAL



April 3, 2019

WATER.— SEWER — STORMWATER — STREET LIGHTING

ENTERPRISE FUNDS

"Serving our Community, Protecting our Environment

SALT LAKE CITY DEPARTMENT OF PUBLIC UTILITIES
RECOMMENDED BUDGET FOR FISCAL YEAR 2020

Public Utilities

Salt Lake City Department of Public Utilities

I recommend for approval, rates, operations, personnel changes and the capital program as herein presented as the Salt Lake City Department of Public Utilities FY2020 Proposed Budget:

Laura Briefer, Director______________________________

Public Utilities Advisory Committee (PUAC)

The PUAC concurs with and supports the Salt Lake City Department of Public Utilities FY2020 Proposed Budget presentation:

Ted Wilson, Chair______________________________

Dated March 28, 2019

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Executive Summary FY 2020

Salt Lake City Department of Public Utilities (Department) is pleased to present its recommended budget for fiscal year 2019-2020 (FY2020). In addition to ongoing operations, the budget as presented includes funding for capital projects in the Water, Sewer, Stormwater, and Street Lighting Utilities to upgrade infrastructure, comply with regulations, and support growth.

As in previous years, a major focus of the Department's budget is in the rehabilitation and replacement of aging infrastructure. The Department has implemented a rigorous capital asset program that assesses the condition and criticality of water infrastructure. This proactive approach mitigates the risk of future failures of water, sewer, and stormwater infrastructure. Infrastructure failure and degradation can lead to public health, water supply, and environmental impacts. The largest planned projects are components of the new Water Reclamation Facility (WRF) that will be completed by 2024, improvements to the Big Cottonwood Water Treatment Plant, construction of a new water transmission line to serve downtown Salt Lake City, conceptual design for a new Public Utilities campus, and Water, Sewer, and Stormwater Utility infrastructure work necessitated by street improvements projects pursuant to the City's passage of a general obligation bond for that purpose.

Funding for capital projects in FY2020 will be generated through the issuance of revenue bonds and rate increases. Total bonding planned for FY2020 is $105,084,000. Proposed rate increases are 5% in the Water Utility, 18% in the Sewer Utility, and 10% in the Stormwater Utility. Street Lighting rates will remain the same. For future years, the Department is investigating the use of a federal low interest loan program for utility infrastructure as an additional funding source.

Summary of Utilities Fund Budgets

Utility Funds FY 2020	Operations	Capital	Debt	Fund Totals
Water	66,275,770	61,764,547	1,781,000	129,821,317
Sewer	21,024,164	107,064,500	13,456,000	141,544,664
Storm	7,172,368	13,472,149	1,306,000	21,950,517
Street	2,963,277	1,725,000	103,000	4,791,277
Total	$ 97,435,579	$ 184,026,196	$ 16,646,000	$ 298,107,775

The proposed budget includes the implementation of the structural rate changes to water and sewer rates pursuant to the Department's 2018 Comprehensive Water, Sewer and Stormwater Rate Study, and as presented to the Mayor and City Council. A proposed resolution adopting these structural changes is presented in Appendix A. As part of environmental regulatory requirements, the Utah Department of Environmental Quality is also requiring a City resolution approving the new WRF, which is also included in Appendix A.

The proposed budget includes the addition of 17 new full time equivalent (FTE) positions. These recommended positions are identified to assist the Department in meeting environmental requirements, implementing capital projects, and responding to economic and geographic growth within our service areas. The Department is also proposing two minor organizational structure changes to provide for succession planning and increased efficiency. Specific rationale is provided for these positions in Appendix B of this document.

As part of Mayor Biskupski's energy and climate initiative, the Department was requested to identify projects within the FY2020 Budget that demonstrate reductions in energy use through efficiency and/or renewable energy projects. Appendix C of this document summarizes the Department's Energy Management and Greenhouse Mitigation Projects and highlights several capital projects in each of the Department's four utilities that demonstrate energy and greenhouse gas reductions.

Budget Summary

The total proposed Department budget is $298,107,775, a 2.00% increase from the FY2019 amended budget of $292,268,301. The adopted budget was adjusted for FY2018 carryover encumbrances for open contracts and purchase orders. Those changes are reflected in the amended budget amount. The proposed operating budget of $97,435,579 is $2,054,167 or 2.15% higher than the current year. The increase includes the proposed new FTEs, a 3% cost of living adjustment (COLA) and a 7% increase in health insurance premiums. This also reflects a 3% rate increase for water purchased from the Metropolitan Water District of Salt Lake and Sandy (MWDSLS).

The proposed capital budget for FY2020 is $184,026,196. Debt service is anticipated to be $16,646,000, including the cost of issuing new debt during the year. Total debt service for FY2020 is increasing due to the cost of issuing new debt and the payment of the initial installment due on a state loan.

Proposed Department of Public Utilities Expenditures for FY 2019-20

Major Expenditure Categories	Adopted Budget 2018-2019	Amended Budget 2018-2019	Proposed Budget 2019-2020	Difference	Percent Change
Personal Services	35,516,006	35,516,006	38,021,063	2,505,057	7.05%
Materials and Supplies	6,346,750	6,362,247	6,733,060	370,813	5.83%
Charges for Services	49,321,529	53,503,159	52,681,456	(821,703)	-1.54%
Debt Service	8,317,000	8,317,000	16,646,000	8,329,000	100.14%
Capital Outlay	11,076,468	11,144,372	11,931,596	787,224	7.06%
Capital Improvements	123,721,000	177,425,517	172,094,600	(5,330,917)	-3.00%
Total	**$ 234,298,753**	**$ 292,268,301**	**$ 298,107,775**	**$ 5,839,474**	**2.00%**

The proposed budget includes projects rated as high priority in the Department's Capital Asset Program (CAP). The major capital improvement projects categories in the FY2020 budget are included in each Utility's budget description in the following sections. A detailed list of capital improvement projects is included in the cash flow summaries for each utility.

The Department's total anticipated revenues for FY2020 are $249,137,157, an increase of $109,630,160. Proposed rate increases are expected to generate $10,138,168 and the issuance of $105,084,000 in bonds account for the remaining increase. The Department intends to balance the budget utilizing $48,970,618 of reserves in all Utility funds. The reserves include the remaining balance of approximately $30 million from the 2017 bond issue.

Projected Department of Public Utilities Revenues for FY 2019-20

Revenue	Adopted Budget 2018-2019	Amended Budget 2018-2019	Proposed Budget 2019-2020	Difference	Percent Change
Operating Sales	123,992,012	123,992,012	134,130,180	10,138,168	8.18%
Interest	1,512,000	1,512,000	883,820	(628,180)	-41.55%
Permits	70,000	70,000	70,000	-	0.00%
Interfund Charges	2,449,985	2,449,985	2,475,157	25,172	1.03%
Other Revenues	833,000	833,000	833,000	-	0.00%
Impact Fees	1,400,000	1,400,000	1,900,000	500,000	35.71%
Contributions	3,895,000	3,895,000	3,761,000	(134,000)	-3.44%
Bond Proceeds	5,355,000	5,355,000	105,084,000	99,729,000	1862.35%
From (To) Reserves	94,791,756	152,761,304	48,970,618	(103,790,686)	-67.94%
Total	**$ 234,298,753**	**$ 292,268,301**	**$ 298,107,775**	**$ 5,839,474**	**2.00%**

Department revenues are generally predictable for all funds except water which is based on changes in seasonal use due to weather during the summer. A cooler, wetter summer and spring will reduce water demand and sales. The Department's water conservation rate structure and conservation education have and continue to be effective as customer's sensitivity to water usage has been proactive. The current water availability and storage reservoirs will have adequate coverage FY 2020, therefore water revenues are forecast on a normal or average expected usage.

Summary of Additional Proposed Positions

The Department currently has 422.50 FTEs and is proposing the following positions to meet identified needs. The Department is proposing adding 17 FTEs as shown in the following chart. A detailed description of these positions is provided in Appendix B.

Proposed Personnel Adjustments FY 2019- 2020

Administration	Water	Sewer	Stormwater	Street Lighting	Total
Engineering Technician I	-	-	-	1.00	1.00
Records Technician	0.80	0.10	0.10	-	1.00
Engineer II	0.50	0.25	0.25	-	1.00
Community & Engagement Coordinator	0.50	0.40	0.10	-	1.00
Sustainability Program Manager	1.00	-	-	-	1.00
					5.00
Water Reclamation Facility					
Pretreatment Inspector/Permit Writer		1.00			1.00
Pretreatment Senior Sampler/Inspector		1.00			1.00
FOG/Sewer Rate Program Supervisor		1.00			1.00
Office Technician II		1.00			1.00
					4.00
Maintenance					
Senior Water System Maintenance Worker	1.00				1.00
					1.00
GIS					
GIS Leak Detector II	0.50	0.30	0.20		1.00
					1.00
Engineering					
Engineering Technician II	1.00	0.50	0.50		2.00
Engineering Technician III	0.50	0.25	0.25		1.00
Engineer III	1.00	0.50	0.50		2.00
					5.00
Seasonal Positions					
Watershed Worker (2)	1.00				1.00
					1.00
Total New FTEs	**7.80**	**6.30**	**1.90**	**1.00**	**17.00**

Water Utility Enterprise Fund

Water Infrastructure Background

The Salt Lake City water system is one of the oldest and largest systems west of the Mississippi River with over 1,125 miles of 12" or smaller distribution lines, and more than 180 miles of large transmission mains for a total asset inventory of 1,305 miles of pipe with over fifty pressure zones. The service area covers the Salt Lake City corporate boundaries as well as the east side of the Salt Lake Valley to the mouth of Little Cottonwood Canyon—a total of 134 square miles. This includes water supply to the newly incorporated Mill Creek City, as well as Cottonwood Heights, Holladay, and small portions of Murray, Midvale, and South Salt Lake Cities. The Department's asset management program includes personnel and systems to assess the condition of the large water transmission mains, treatment and pumping plants, and other infrastructure to assure repair and replacement is completed with minimal impact to the public. Each of the Department's three water treatment plants were originally constructed in the 1950's and have undergone numerous upgrades. There is also a continual need to repair and replace pipe segments to maintain service and reduce emergency repair costs and impacts to the public.

Water Utility Budget Highlights for FY2020

Anticipated Revenues

A proposed 5% rate increase is anticipated to generate an additional $2,442,107. Proposed rates for FY2020 are impacted by two elements: 1) implementation of a rate structure and cost of service study that was finalized in October 2018 and 2) the proposed rate increase. The additional revenue is required for the water utility to meet its capital and operations objectives.

The Department plans to issue bonds during FY2020 with $35,196,000 designated for water. Additional bonding of $112,627,000 is anticipated from FY 2021 to FY2024 meet water utility capital project objectives.

The revenue budget is proposed to increase by $7,026,186 or 5.72% from the FY2019 budget. The proposed budget for FY2020 by major category is as follows:

Projected Water Revenues for FY 2019-20

Revenue	Adopted Budget 2018-2019	Amended Budget 2018-2019	Proposed Budget 2019-2020	Difference	Percent Change
Operating Sales	73,289,346	73,289,346	75,731,453	2,442,107	3.33%
Interest	375,000	375,000	229,000	(146,000)	-38.93%
Interfund Charges	2,449,985	2,449,985	2,475,157	25,172	1.03%
Other Revenues	638,000	638,000	638,000	-	0.00%
Impact Fees	500,000	500,000	1,000,000	500,000	100.00%
Contributions	1,205,000	1,205,000	1,205,000	-	0.00%
Bond Proceeds	-	-	35,196,000	35,196,000	
From (To) Reserves	25,735,446	44,337,800	13,346,707	(30,991,093)	-69.90%
Total	**$ 104,192,777**	**$ 122,795,131**	**$ 129,821,317**	**$ 7,026,186**	**5.72%**

Operating Sales: The implementation of the new rate structure combined with the 5% proposed rate increase is estimated to generate $2,442,107 or 3.33% more than the FY2019 budgeted amount. The implementation of both has no impact on the monthly billing for residential usage of 21 CCF

Interest Income: Interest earnings are expected to decrease as reserve funds are invested in capital improvements.

Interfund Charges: The Water Utility is reimbursed by Sewer, Stormwater, Street Lighting, Refuse, and the Hive program for services related to billing. Related revenue is not expected to change significantly.

Impact Fees: Impact fees are budgeted to increase $500,000 for new development. The FY2020 budget is a conservative estimate based on the historical average.

Bond Proceeds: A bond issue of $35,196,000 million is anticipated.

Reserve Funds: The Department plans to use $13,346,707 of reserve funds to balance the capital and operational needs. Budgeted use of reserve funds is <$30,991,093> less than the FY2019 amended budget or a decrease of <69.90%>.

Proposed Expenditures

The Water Utility's FY2020 budget includes a decrease of <$1,182,293> in other professional and technical services which is off-set by a $1,317,556 increase in personal services. The increase in personal services is attributed to the addition of 7.80 FTEs, a 3% COLA for employees, and a 7% increase in health insurance costs. The new FTEs requested will support the Department's water quality, engineering, water operations, and administration service offerings to benefit residents of the Water Utility's water service area.

The Department expects a $479,845 or 3% increase in the price of water from Metropolitan District of Salt Lake and Sandy for FY2020.

The Department plans to invest $59,255,100 in capital improvements for Water Utility infrastructure in FY2020. The capital improvement program includes a prioritized balance of needed improvements to treatment plants, water lines, meter replacements, pump stations, wells, and other infrastructure.

The schedule for some water main replacements has been accelerated to perform work in conjunction with the General Fund bonded street repair projects. The FY 2020 capital improvements budget includes $9,650,000 for these replacements. Future years anticipate an additional $17,890,000 in projects related to the proposed street related projects that are part of the 2018 general obligation bond for streets. The water main budget also includes the $10,000,000 for the East West Conveyance Line.

The expenditure budget for the Water Utility is proposed to increase $7,026,186 or 5.72% from the FY2019 budget. The proposed budget for FY2020 by major category is as follows:

Proposed Water Expenditures for FY 2019-20

Major Expenditure Categories	Adopted Budget 2018-2019	Amended Budget 2018-2019	Proposed Budget 2019-2020	Difference	Percent Change
Personal Services	22,069,746	22,069,746	23,387,302	1,317,556	5.97%
Materials and Supplies	4,218,280	4,233,777	4,415,380	181,603	4.29%
Charges for Services	36,600,851	39,051,011	38,473,088	(577,923)	-1.48%
Debt Service	1,117,000	1,117,000	1,781,000	664,000	59.44%
Capital Outlay	4,614,400	4,682,304	2,509,447	(2,172,857)	-46.41%
Capital Improvements	35,572,500	51,641,293	59,255,100	7,613,807	14.74%
Total	**$ 104,192,777**	**$ 122,795,131**	**$ 129,821,317**	**$ 7,026,186**	**5.72%**

Personal Services: Employee related costs are estimated to increase $1,317,556 or 5.97%. The water utility budget anticipates an increase of 7.80 FTEs. The FY2020 budget includes a 3% COLA and a 7% increase in costs of health insurance.

Materials & Supplies: The increase of $181,603 is driven by a $110,000 increase in sand and gravel as well as increases in grounds and building supplies and computer supplies. Small tools and equipment decreased from last year.

Charges for Services: The proposed budget for charges and services will decrease <$577,923> or <1.63%>. The decrease can be attributed to a <$1,182,293>decrease in outsourced technical services and a <$111,000> decrease in payment in lieu of taxes that are offset by the price increase for water purchases from Metropolitan Water District.

Debt Service: - In compliance with the Series 2017 Refunding Bond, and in anticipation of a Series 2020—3.9%, 30 Year—Bond, the budget for debt service increased by $664,000.

Capital Outlay: The proposed budget for capital outlay for FY2020 includes $1,500,000 for watershed purchases, $30,000 for water rights, $494,265 for 14 vehicles, $175,182 for field equipment, $50,000 for pumping equipment, $60,000 for treatment plant equipment, $50,000 for telemetry, $30,000 for office furniture & equipment, and $120,000 for other non-motive equipment.

Capital Improvements: The Water proposed CIP budget for FY2020 is $59,255,100. A detailed list of CIP projects is included in the cash flow summaries for the Water Utility. A capital project summary by facility type is as follows:

Proposed Water Capital Improvement Program for FY 2019-20

Type of Project	Proposed Budget 2019-2020
Treatment Plants	7,850,000
Water Service Connections	5,900,000
Pumping Plant Upgrades	1,565,000
Reservoirs	3,435,000
Water Mains and Hydrants	35,530,100
Wells	3,400,000
Culverts, Flumes, and Bridges	1,455,000
Watershed	120,000
Total 2019-2020 CIP	**$ 59,255,100**

Sewer Utility Enterprise Fund

Sewer Infrastructure Background

The City's Water Reclamation Facility (WRF) was constructed in 1965 and has undergone numerous upgrades since. Nutrient removal regulations adopted by the Utah Department of Environmental Quality (UDEQ) in 2015 require a new sewage treatment process. After much study, the Department determined that the WRF has reached the end of its useful life and adapting the 54 year old facility to meet the new nutrient removal requirements is not feasible. A new WRF is currently under design, to be completed by 2024 in order to meet UDEQ's nutrient compliance date of January 1, 2025. The Department has been implementing gradual rate increases and revenue bonding for the replacement of the WRF.

The sewer collection system (654 miles of pipeline, and several pump stations in 2018) is a very challenging environment; hydrogen sulfide gases, sediment, roots and other factors affect the competency of the collection lines. The Department's asset management program includes personnel and systems to assess the condition of the large water transmission mains, treatment and pumping plants, and other infrastructure to assure repair and replacement is completed with minimal impact to the public. More than 50% of the sewer collection system is greater than 85 years old.

The Department is expanding portions of the sewer collection system, in large part to meet growth requirements related to the new State Correctional Facility, the Airport expansion, and new development anticipated in the Northwest Quadrant of Salt Lake City.

Sewer Utility Budget Highlights for FY2020

Total project costs for the WRF reconstruction are anticipated to be $528,130,000 when the project is completed. Construction will begin in FY2020. Public Utilities has expended approximately $6 million over the last several years in preparation for this project.

Current financing for the new WRF is anticipated to be accomplished using a combination of revenue bonds and user rates. The Department plans to submit a letter of interest in spring 2019 for consideration to apply for federal loans pursuant to the Water Infrastructure Finance and Innovation Act (WIFIA). If invited to apply, the program loan would provide up to 49% of the cost of the new WRF. The interest rate is locked in at loan closing and repayment schedules can be structured to complement revenue bond debt payments. If a loan is not approved, the project costs will be funded through revenue bonds. The two scenarios are as follows:

Scenario 1: Sewer Planned Debt

FY	WIFIA	Bonds	Total
2019-2020	-	55,000,000	55,000,000
2020-2021	67,429,000	51,450,000	118,879,000
2021-2022	85,926,000	59,180,000	145,106,000
2022-2023	65,057,000	62,230,000	127,287,000
2023-2024	31,865,000	27,440,000	59,305,000
Total	**$ 250,277,000**	**$ 255,300,000**	**$ 505,577,000**

Scenario 2: Sewer Planned Debt

FY	Bonds
2019-2020	55,000,000
2020-2021	107,000,000
2021-2022	187,000,000
2022-2023	138,000,000
2023-2024	69,000,000
Total	**$ 556,000,000**

Anticipated Revenues

A proposed 18% rate increase is anticipated to generate an additional $6,782,334 in sewer fees. Proposed rates for FY2020 are impacted by two elements: 1) implementation of a rate and cost of service study that was finalized in October 2018; and 2) the proposed rate increase. The additional revenue is required for the Sewer Utility to meet its capital and operations objectives. Rate increases in future years are also anticipated at this time. The rate increases are anticipated to vary based on the source of debt.

Forecast Rate Increases

FY	WIFIA/Bonds	Bonds	Difference
2019-2020	18%	18%	0%
2020-2021	18%	20%	-2%
2021-2022	18%	25%	-7%
2022-2023	15%	25%	-10%
2023-2024	10%	10%	0%
Average	**16%**	**20%**	**-4%**

The Department plans to issue bonds during FY2020 with $55,307,000 designated for the Sewer Utility. Additional debt of $471,287,000 is anticipated from FY2021 to FY2024 to meet Sewer Utility capital objectives, primarily the reconstruction of the WRF. Debt will be used in conjunction with rate increases to blend pay as you go and borrowing strategies. The proposed debt is for a 30 year term creating intergenerational equity payback on the new WRF facility. The process will engage the City's professional advisors to measure debt service and ratios to comply with external rating agency standards. The Department intends to maintain its AAA rating to limit costs of borrowing.

The total revenue budget is expected to decrease by <$6,540,494> or <4.42%> to $141,544,664 from the FY2019 amended budget. A reduction in the budgeted use of reserve funds is driving the decrease. The proposed budget for FY2020 by major category is as follows:

Projected Sewer Revenues for FY 2019-20

Revenue	Adopted Budget 2018-2019	Amended Budget 2018-2019	Proposed Budget 2019-2020	Difference	Percent Change
Operating Sales	37,677,666	37,677,666	44,460,000	6,782,334	18.00%
Interest	1,052,000	1,052,000	604,000	(448,000)	-42.59%
Permits	70,000	70,000	70,000	-	
Other Revenues	185,000	185,000	185,000	-	0.00%
Bond/ Note Proceeds	4,000,000	4,000,000	55,307,000	51,307,000	1282.68%
Impact Fees	700,000	700,000	700,000	-	0.00%
Contribution	2,020,000	2,020,000	2,020,000	-	
From (To) Reserves	65,246,893	102,380,492	38,198,664	(64,181,828)	-62.69%
Total	**$ 110,951,559**	**$ 148,085,158**	**$ 141,544,664**	**$ (6,540,494)**	**-4.42%**

<u>Sewer service fees</u>: Sewer service fees are expected to increase $6,782,334 or 18%. The proposed rate increase is approximately $5.04 per month for the representative resident (assuming winter water use of eight CCF). The increase reflects the implementation of the new rate structure and the 18% rate increase. The additional revenue is required for the sewer utility to meet its capital and operations objectives

<u>Interest Income</u>: Interest earnings are expected to decrease as reserve funds and remaining bond proceeds are invested in capital improvements.

<u>Bond / Note Proceeds:</u> A bond issue of $55,307,000 is anticipated.

<u>Reserve Funds</u>: Reserve funds of $38,198,664, including funds from the 2017 Bond issue, will balance the Sewer Utility's capital and operational needs with FY2020 revenue. Budgeted use of reserve funds decreases <$64,181,828> from the FY2019 budget.

Proposed Expenditures

The proposed sewer budget for FY2020 includes $98,370,500 in planned projects. Of this amount $54,700,000 is planned for the new WRF facility, $6,380,000 for the existing plant, and $36,630,500 for improvements to the sewer collections system. The schedule for some sewer collection line replacements has been accelerated to perform work in conjunction

with the City's general obligation bonded street repair projects. The FY2020 capital improvements budget includes $4,850,000 for these replacements. Future years anticipate an additional $21,200,000 to support the general obligation of the bonded street related projects.

The Sewer Utility's FY 2020 budget proposes a decrease of <$6,540,494> or <4.42%> from the FY2019 amended budget. The proposed budget for FY2020 by major category is as follows:

Proposed Sewer Expenditures for FY 2019-20

Major Expenditure Categories	Adopted Budget 2018-2019	Amended Budget 2018-2019	Proposed Budget 2019-2020	Difference	Percent Change
Personal Services	10,375,345	10,375,345	11,164,232	788,887	7.60%
Materials and Supplies	1,934,720	1,934,720	2,109,430	174,710	9.03%
Charges for Services	6,211,994	7,115,552	7,750,502	634,950	8.92%
Debt Service	6,073,000	6,073,000	13,456,000	7,383,000	121.57%
Capital Outlay	5,946,500	5,946,500	8,694,000	2,747,500	46.20%
Capital Improvements	80,410,000	116,640,041	98,370,500	(18,269,541)	-15.66%
Total	**$ 110,951,559**	**$ 148,085,158**	**$ 141,544,664**	**$ (6,540,494)**	**-4.42%**

Personal Services: Employee related costs are estimated to increase $788,887 or 7.60%. The sewer utility budget anticipates an increase of 6.30 FTEs. The FY2020 budget includes a 3% COLA and a 7% increase in costs of health insurance.

Materials & Supplies: The Sewer Utility's budget for this category increased by $174,710. This increase is attributed to laboratory supplies, chemicals, and small tools and equipment:

Charges for Services: The budget for charges and services increased by $634,950. The most significant items in this category are an increase in data processing services of $113,000 and a $293,013 increase in payment in lieu of taxes.

Debt Service: - The annual debt service budget is expected to increase by $7,383,000 in FY2020. A payment of $6,375,000 on a note payable is required during the year. The remaining increase is in accordance with existing debt service schedules and planned bond issues.

Capital Outlay: - The proposed capital outlay budget for FY2020 includes $5,600,000 for land, $1,717,500 for a vehicles and trucks, $408,000 for field maintenance equipment, $778,500 treatment plant equipment, $10,000 for telemetry, $20,000 for office furniture and equipment, and $160,000 for other non-motive equipment.

Capital Improvements: The Sewer proposed CIP budget for FY2020 is $98,370,500, a decrease of <$18,269,541> from the current year amended budget. A detailed list of capital improvement projects is included in the cash flow summary for the Sewer Utility. A capital project summary by facility type is as follows:

Proposed Sewer Capital Improvement Program for FY 2019-20

Type of Project	Proposed Budget 2019-2020
WRF	61,080,000
Collection System	36,630,500
Lift Stations	510,000
Northwest Oil Drain	150,000
Total 2019-2020 CIP	**$ 98,370,500**

Stormwater Utility Enterprise Fund

Stormwater Infrastructure Background

The Drainage Master Plan was completed in 1993. The FY2020 budget includes an update of the Drainage Master Plan to address water quality and climate change issues, such as storm intensification. The projects identified in the Master Plan provide direction and areas that may or have already been completed. In the last ten years 34.4 miles of storm drain pipe has been installed.

Stormwater Utility Budget Highlights for FY2020

Anticipated Revenues

A proposed 10% rate increase or approximately $0.49 per equivalent residential unit (ERU) per month is included in the budget. Dwindling cash reserves, stronger regulatory requirements and infrastructure needs are drivers for the proposed rate increase. Additional rate increases between 10% and 6% are projected through FY2023.

The Department plans to issue bonds during FY2020 with $14,581,000 designated for stormwater utility needs. Additional bonding is planned in FY 2022.

The revenue budget is proposed to increase by $6,228,860 or 39.62% from the FY2019 budget. The proposed revenue budget for FY2020 by major category is as follows:

Projected Storm Revenues for FY 2019-20

Revenue	Adopted Budget 2018-2019	Amended Budget 2018-2019	Proposed Budget 2019-2020	Difference	Percent Change
Operating Sales	8,855,000	8,855,000	9,740,500	885,500	10.00%
Interest	33,000	33,000	20,820	(12,180)	-36.91%
Other Revenues	200,000	200,000	200,000	-	0.00%
Impact Fees	650,000	650,000	516,000	(134,000)	-20.62%
Contributions	1,000	1,000	1,000	-	0.00%
Bond Proceeds	1,355,000	1,355,000	14,581,000	13,226,000	
From (To) Reserves	2,492,300	4,627,657	(3,108,803)	(7,736,460)	-167.18%
Total	**$ 13,586,300**	**$ 15,721,657**	**$ 21,950,517**	**$ 6,228,860**	39.62%

Operating Sales: A rate increase of 10% or about $0.49 per ERU per month is estimated to generate $885,500 more than the current budget.

Interest Income: Interest earnings are expected to decrease as reserve funds are invested in capital improvements.

Contributions by Developers: Decrease of <$134,000> related to reimbursed cost sharing from oil companies related to Northwest Oil Drain remediation.

Bond / Note Proceeds: A bond issue of $14,581,000 is anticipated.

Reserve Funds: Unspent bond proceeds of $3,108,803 will be added to reserves for use on stormwater system improvements

Proposed Expenditures

The Stormwater Utility's FY2020 budget proposes capitalizing $12,744,000 to renovate portions of the stormwater collection system. The schedule for stormwater system improvements has been accelerated to perform work in conjunction with the general obligation bonded street repair projects. The FY2020 capital improvements budget includes $3,550,000 for these. Future years anticipate an additional $14,725,000 in the bonded street related projects. These capital items will be funded through rate increases and revenue bonds.

The expenditure budget for the Stormwater Utility is proposed to increase $6,228,860 or 39.62% from the current year FY2019 budget. The proposed budget for fiscal year FY2020 by major category is as follows:

Proposed Storm Expenditures for FY 2019-20

Major Expenditure Categories	Adopted Budget 2018-2019	Amended Budget 2018-2019	Proposed Budget 2019-2020	Difference	Percent Change
Personal Services	2,872,608	2,872,608	3,187,954	315,346	10.98%
Materials and Supplies	186,450	186,450	200,950	14,500	7.78%
Charges for Services	3,854,174	4,600,262	3,783,464	(816,798)	-17.76%
Debt Service	1,024,000	1,024,000	1,306,000	282,000	27.54%
Capital Outlay	515,568	515,568	728,149	212,581	41.23%
Capital Improvements	5,133,500	6,522,769	12,744,000	6,221,231	95.38%
Total	**$ 13,586,300**	**$ 15,721,657**	**$ 21,950,517**	**$ 6,228,860**	**39.62%**

Personal Services: Employee related costs are estimated to increase $315,346 or 10.98%. The stormwater utility budget anticipates an increase of 1.90 FTEs. The FY2020 budget includes a 3% COLA and a 7% increase in costs of health insurance.

Charges for Services: The decrease in this category is driven by planned reductions of <$836,222> in professional and consulting services. This decrease is partially offset by an increase in planned data processing costs.

Debt Service: The budget increases by $282,000 or 27.54% in anticipation of a Series 2020—3.9%, 30 Year—Bond.

Capital Outlay: The proposed capital outlay budget for FY2020 includes $672,649 for vehicles and $56,000 for various categories of equipment.

Capital Improvements: The Stormwater proposed capital improvement budget for FY2020 is $12,744,000, an increase of $6,221,231 over the FY2019 budget. A detailed list of

capital improvement projects is provided in the cash flow summary for the Stormwater Utility. The capital project summary by facility types are as follows:

Proposed Storm Capital Improvement Program for FY 2019-20

Type of Project	Proposed Budget 2019-2020
Lines and Riparian Corridor Projects	12,530,000
Lift Stations	64,000
Northwest Oil Drain	150,000
Total 2019-2020 CIP	**$ 12,744,000**

Street Lighting Utility Enterprise Fund

Street Lighting Infrastructure Background

The responsibility for provision of street lighting throughout the city was transferred to the Department from the General Fund in 2013. The Department is currently updating the City's 2006 Street Lighting Master Plan in order to focus on community safety and aesthetic needs, particularly since updating lights and conversion of street lights to energy efficiency bulbs has changed the character of lighting in some neighborhoods.

Of the 15,662 lights that the City maintains, 8,398 lights or 54% are now considered to be energy efficient. We are in the seventh year of a ten-year plan to convert all the lights to high energy efficiency lamps. The FY2020 budget funds continuing conversion to high efficiency lights. Ongoing conversions are anticipated in some neighborhoods once the Street Lighting Master Plan is completed to provide better guidelines related to lighting color and intensity. The Street Lighting Utility is saving energy that has approximately $300,000 favorable effect on the FY2020 budget and a similar effect in future years. There have been and may still be energy saving rebates available as the conversion continues.

Street Lighting Utility Budget Highlights for FY2020

Anticipated Revenues

No rate changes are proposed in the FY2020 budget or forecast in the immediate future. The base lighting rates were established in 2013 at $3.73 per month for an average residential customer, or Equivalent Residential Unit (ERU), and are expected to remain unchanged for this fiscal year. Rates for enhanced tiers are Tier 1 $5.67, Tier 2 $15.94, and Tier 3 $43.82.

Continuation of the private lights program is proposed in the FY2020 budget. The program includes a $20,000 transfer from the General Fund and indicates the on-going desire of the City to provide a matching support to reduce the capital costs to neighborhoods installing private street lighting. Public Utilities administers this program.

The revenue budget is proposed to decrease by <$875,078> from the FY2019 budget. The proposed budget for FY2020 by major category is as follows:

Projected Street Revenues for FY 2019-20

Revenue	Adopted Budget 2018-2019	Amended Budget 2018-2019	Proposed Budget 2019-2020	Difference	Percent Change
Operating Sales	4,170,000	4,170,000	4,198,227	28,227	0.68%
Interest	52,000	52,000	30,000	(22,000)	-42.31%
Other Revenues	9,000	9,000	9,000	-	0.00%
General Fund Contributions	20,000	20,000	20,000	-	0.00%
From (To) Reserves	1,317,117	1,415,355	534,050	(881,305)	-62.27%
Total	**$ 5,568,117**	**$ 5,666,355**	**$ 4,791,277**	**$ (875,078)**	**-15.44%**

Operating Sales: Rate changes are not proposed thus this category is not expected to change significantly. The FY2020 budget is based on actual revenue sales from FY2018

Interest Income: Interest earnings are expected to decrease as reserve funds are utilized.

General Fund Contributions: No change. Public Utilities anticipates the general fund to continue contributing $20,000 for private light options in FY2020.

Reserve Funds: The FY2020 budget anticipates using $534,050 from the utility's reserve funds—mostly unspent bond proceeds from the 2017 bond issue.

Proposed Expenditures

Street Lighting capital improvements totaling $1,725,000 are planned in the FY2020 budget. The Street Lighting Capital Program focuses on high efficiency and system

upgrades in neighborhood, arterial and collector streets and includes $200,000 for lighting controls

The expenditure budget for the Street Lighting Utility is proposed to decrease <$875,078> or <15.44%> from the FY2019 amended budget. The proposed budget for FY2020 by major category is as follows:

Proposed Street Expenditures for FY 2019-20

Major Expenditure Categories	Adopted Budget 2018-2019	Amended Budget 2018-2019	Proposed Budget 2019-2020	Difference	Percent Change
Personal Services	198,307	198,307	281,575	83,268	41.99%
Materials and Supplies	7,300	7,300	7,300	-	0.00%
Charges for Services	2,654,510	2,736,334	2,674,402	(61,932)	-2.26%
Debt Service	103,000	103,000	103,000	-	0.00%
Capital Improvements	2,605,000	2,621,414	1,725,000	(896,414)	-34.20%
Total	**$ 5,568,117**	**$ 5,666,355**	**$ 4,791,277**	**$ (875,078)**	**-15.44%**

Personal Services: Employee related costs are estimated to increase $83,268 of 41.99%. The Street Lighting Utility budget anticipates an increase of 1 FTE. The FY2020 budget includes a 3% COLA and a 7% increase in costs of employee insurance premiums.

Charges for Services: The proposed budget for charges and services decreases <$61,932> or <2.26%> in FY2020 with a <$81,824> budgeted decrease in professional services off-set by an increase in budgeted power costs.

Debt Service: In compliance with the outstanding bond, Series 2017 Bond, budgeted debt service payments remain unchanged in FY2020.

Capital Equipment: No expenditures for capital equipment are planned.

<u>Capital Improvements</u>: The proposed Street Lighting CIP budget for FY2020 is $1,725,0000, a decrease of <$896,414> from the FY2019 amended budget. A capital projects summary by facility type is as follows for base lighting and all enhanced tiers:

Proposed Street Capital Improvement Program for FY 2019-20

Type of Project	Proposed Budget 2019-2020
System upgrade for high efficiency and uniformity	1,525,000
Lighting controls	200,000
Total 2019-2020 CIP	**$ 1,725,000.00**

Combined Utilities- Budget Summary and Cash Flow

PUBLIC UTILITIES
WATER, SEWER, STORMWATER, AND STREET LIGHTING ENTERPRISE FUNDS
COMBINED BUDGET SUMMARY
2020-2022 BUDGET

Combined Annual Rate Increase				8.2%	10.0%	10.1%
SOURCES	ACTUAL 2017-2018	AMENDED BUDGET 2018-2019	PROJECTED ACTUAL 2018-2019	PROPOSED BUDGET 2019-2020	FORECAST BUDGET 2020-2021	FORECAST BUDGET 2021-2022
REVENUES						
METERED SALES	$111,480,405	$119,822,012	$118,657,859	**$129,931,953**	$143,336,576	158,243,087
INTEREST INCOME	2,630,722	1,512,000	1,512,000	**883,820**	$318,816	185,338
OTHER REVENUES	5,931,175	3,282,985	3,284,985	**3,308,157**	$3,308,157	3,308,157
STREET LIGHTING FEES	4,198,227	4,170,000	4,198,227	**4,198,227**	$4,198,227	4,198,227
TOTAL REVENUES	$124,240,529	$128,786,997	$127,653,071	**$138,322,157**	$151,161,776	165,934,809
OTHER SOURCES						
GRANTS & OTHER RELATED REVENUES	$3,333,556	$3,875,000	$3,875,000	**$3,741,000**	$3,741,000	2,441,000
IMPACT FEES	2,858,059	1,400,000	1,400,000	**1,900,000**	1,924,500	1,949,858
TRANSFERS FROM GENERAL FUND	20,000	20,000	20,000	**20,000**	20,000	20,000
BOND PROCEEDS	0	0	0	**105,084,000**	81,453,000	129,847,200
NON BOND FINANCING	8,500,000	4,000,000	0	**0**	67,429,000	85,926,000
SHORT-TERM FINANCING	0	1,355,000	0	**0**	0	0
COUNTY FLOOD CONTROL	0	0	0	**0**	0	0
OTHER SOURCES	118,152	70,000	70,000	**70,000**	70,000	70,000
T O T A L OTHER SOURCES	$14,829,767	$10,720,000	$5,365,000	**$110,815,000**	$154,637,500	220,254,058
T O T A L SOURCES	$139,070,296	$139,506,997	$133,018,071	**$249,137,157**	$305,799,276	386,188,867
EXPENSES & OTHER USES						
EXPENDITURES						
PERSONNEL SERVICES	$30,935,175	$35,516,006	$35,516,006	**$38,021,063**	$39,541,905	41,123,577
OPERATING & MAINTENANCE	$4,951,624	6,362,247	$6,362,247	**$6,733,060**	6,856,022	6,993,143
TRAVEL & TRAINING	$101,729	249,058	$249,058	**304,773**	310,870	317,086
UTILITIES	$4,289,708	5,069,662	$5,069,662	**5,034,877**	5,074,877	5,123,765
TECHNICAL SERVICES	$7,156,710	15,878,757	$15,878,757	**13,638,603**	12,572,550	12,529,406
DATA PROCESSING	$1,765,209	1,487,047	$1,487,047	**1,876,347**	1,913,875	1,952,151
PUBLIC SERVICES / STREET SWEEPING	$819,605	819,605	$819,605	**819,605**	835,997	852,717
FLEET MAINTENANCE	1,821,898	2,007,000	$2,007,000	**2,007,000**	2,047,140	2,088,082
ADMINISTRATIVE SERVICE FEE	1,089,863	1,225,000	$1,225,000	**1,251,000**	1,276,020	1,301,540
PAYMENT IN LIEU OF TAXES	814,795	970,192	$970,192	**1,126,697**	1,149,231	1,172,216
RISK MANAGEMENT	1,313,881	1,484,033	$1,484,033	**1,468,353**	1,497,720	1,527,673
TRANSFERS TO GENERAL FUND	0	109,000	$109,000	**89,000**	90,780	92,596
BILLING COST	1,237,745	1,368,013	$1,368,013	**1,373,051**	1,400,512	1,428,523
BONDING NOTE EXPENSE	0	0	$0	**-**	-	-
METRO. WATER PURCH & TREAT	15,528,950	15,994,818	$15,994,818	**16,474,663**	16,968,903	17,477,971
METRO ASSESSMENT (CAPITAL)	7,021,892	7,021,892	$7,021,892	**7,021,892**	7,021,892	7,021,892
OTHER CHARGES AND SERVICES	(869,406)	(180,918)	($180,918)	**195,595**	198,370	202,338
TOTAL EXPENDITURES	$77,979,378	$95,381,412	$95,381,412	**$97,435,579**	$98,756,664	101,204,676
OTHER USES						
CAPITAL OUTLAY	$6,193,492	$11,144,372	$6,716,975	**$11,931,596**	$4,373,000	4,373,000
CAPITAL IMPROVEMENT BUDGET	55,576,281	177,425,517	91,909,315	**172,094,600**	189,219,500	255,098,400
COST OF DEBT ISSUANCE	9,100	25,000	0	**584,000**	453,000	722,200
DEBT SERVICES	7,645,659	8,292,000	8,284,603	**16,062,000**	18,282,000	20,218,000
T O T A L OTHER USES	$69,424,532	$196,886,889	$106,910,893	**$200,672,196**	$212,327,500	280,411,600
T O T A L USES	$147,403,910	$292,268,301	$202,292,305	**$298,107,775**	$311,084,164	381,616,276
EXCESS REVENUE AND OTHER SOURCES OVER (UNDER) USES	($8,333,614)	($152,761,304)	($69,274,234)	**($48,970,618)**	($5,284,888)	4,572,591
OPERATING CASH BALANCES						
BEGINNING JULY 1	$152,753,095	$144,419,481	$144,419,481	**$75,145,247**	$26,174,629	20,889,741
ENDING JUNE 30	$144,419,481	($8,341,823)	$75,145,247	**$26,174,629**	$20,889,741	25,462,332
Cash Reserve Ratio	185%	-9%	79%	**27%**	21%	25%

Cash reserve goal above 10%

PUBLIC UTILITIES

Water, Sewer, Stormwater and Street Lighting Enterprise Funds

Combined Cash Flow

FY 2020 Budget and FY 2021-2024 Forecast Budget

	ACTUAL YEAR 2017-2018	PROJECTED YEAR 2018-2019	BUDGET YEAR 2019-2020	BUDGET YEAR 2020-2021	BUDGET YEAR 2021-2022	BUDGET YEAR 2022-2023	BUDGET YEAR 2023-2024
WATER SALES	69,351,147	72,125,193	75,731,453	79,784,026	83,773,227	87,961,888	93,239,601
SEWER CHARGES	33,620,751	37,677,666	44,460,000	52,838,000	62,791,000	72,718,000	80,548,000
STORMWATER FEES	8,508,507	8,855,000	9,740,500	10,714,550	11,678,860	12,379,591	12,998,571
STREET LIGHTING FEES	4,198,227	4,198,227	4,198,227	4,198,227	4,198,227	4,198,227	4,198,227
TOTAL SERVICES FEES AND CHARGES	115,678,632	122,856,086	134,130,180	147,534,803	162,441,314	177,257,706	190,984,399
OTHER INCOME	5,934,020	3,304,985	3,328,157	3,328,157	3,328,157	3,328,157	3,328,157
INTEREST INCOME	2,630,722	1,512,000	883,820	318,816	185,338	256,254	203,104
OPERATING INCOME	124,243,374	127,673,071	138,342,157	151,181,776	165,954,809	180,842,117	194,515,660
OPERATING EXPENDITURES	(77,986,578)	(95,381,412)	(97,435,579)	(98,756,664)	(101,204,676)	(103,806,581)	(106,203,662)
NET INCOME EXCLUDING DEP.	46,256,796	32,291,659	40,906,578	52,425,112	64,750,133	77,035,536	88,311,998
WIFIA LOAN			0	67429000	85926000	65057000	31865000
NET BOND PROCEEDS	0	0	104,500,000	81,000,000	129,125,000	94,000,000	42,000,000
SHORT TERM FINANCING	0	0	0	0	0	0	0
STATE LOAN	8,500,000	0	0	0	0	0	0
IMPACT FEES	2,858,059	1,400,000	1,900,000	1,924,500	1,949,858	1,976,103	2,003,267
OTHER CONTRIBUTIONS	3,468,863	3,945,000	3,811,000	3,811,000	2,511,000	2,311,000	2,311,000
CAPITAL OUTLAY	(6,193,492)	(6,126,238)	(10,431,596)	(2,873,000)	(2,873,000)	(2,873,000)	(2,873,000)
WATERSHED PURCHASES	0	(590,737)	(1,500,000)	(1,500,000)	(1,500,000)	(1,500,000)	(1,500,000)
STATE LOAND DEBT SERVICE	0	0	(6,375,000)	(2,125,000)	0	0	0
SHORT TERM FINANCING DEBT SERVICE	0	0	0	0	0	0	0
DEBT SERVICE	(7,647,559)	(8,284,603)	(8,297,000)	(10,861,000)	(10,854,000)	(10,851,000)	(11,183,850)
NEW DEBT SERVICE	0	0	(1,390,000)	(5,296,000)	(9,364,000)	(14,459,000)	(20,281,000)
OTHER INCOME & EXPENSE	985,871	(9,656,578)	82,217,404	131,509,500	194,920,858	133,661,103	42,341,417
AVAILABLE FOR CAPITAL	47,242,667	22,635,081	123,123,982	183,934,612	259,670,991	210,696,639	130,653,415
CAPITAL IMPROVEMENTS	(55,576,281)	(91,909,315)	(172,094,600)	(189,219,500)	(255,098,400)	(214,028,000)	(130,399,000)
BEGINING CASH BALANCE	152,753,095	144,419,481	75,145,247	26,174,629	20,889,741	25,462,332	21,880,971
CASH INCREASE/(DECREASE)	(8,333,614)	(69,274,234)	(48,970,618)	(5,284,888)	4,572,591	(3,331,361)	254,415
ENDING BALANCES	144,419,481	75,145,247	26,174,629	20,889,741	25,462,332	22,130,971	22,135,386
DEBT SERVICE COVERAGE	6.05	3.90	4.22	3.24	3.20	3.04	2.81
CASH RESERVE RATIO	185.2%	78.8%	26.9%	21.2%	25.2%	21.3%	20.8%
DEBT SERVICE % OF GROSS OPERATING REVENUE	6.3%	6.5%	6.9%	10.5%	12.1%	13.9%	16.1%
RESIDENTIAL UTILITY BILL	63.65	67.46	70.25	75.76	81.86	87.88	93.81
% CHANGE RESIDENTIAL UTILITY BILL*		6.0%	4.14%	7.8%	8.1%	7.4%	6.7%

*** Residential Utility Bill assumes annual water consumption of 255 ccf/12 months, 4 ccf monthly of sewer, 1 Stormwater ERU (.25 acres) monthly, and 1 Street Lighting ERU (75 feet) monthly.**

PUBLIC UTILITIES
FEES AND CHARGES PAID TO THE GENERAL FUND
FOR SERVICES RENDERED
OR COLLECTED BY CITY ORDINANCE

DESCRIPTION OF SERVICES	June 30, 2018 ACTUALS WATER	June 30, 2018 ACTUALS SEWER	June 30, 2018 ACTUALS STORM	June 30, 2018 ACTUALS STREET LIGHT	ACTUAL Public Utilities June 30, 2018 TOTALS	FY 2018/2019 BUDGET	FY PROPOSED 2019/2020 BUDGET
Administrative Service Fees (General Fund)							
Human Resources	$ 144,501	$ 124,064	$ 33,232	$ 1,954	$ 303,751	$ 358,450	**$ 348,670**
City Attorney	135,198	22,364	10,165	2,033	169,760	167,350	**194,860**
Accounting/Finance	131,822	58,626	12,442	3,569	206,459	272,280	**236,980**
Purchasing & Contracts	66,060	27,842	3,213	2,607	99,722	96,130	**114,470**
City Recorders	45,263	7,259	7,651	867	61,040	86,260	**70,060**
Property Management	-	-	-	-	-	7,770	**-**
Budget and Policy	25,667	10,732	3,041	217	39,657	45,780	**45,520**
Non-discretionary IMS Costs	50,630	27,072	13,881	1,094	92,677	197,480	**106,380**
Treasurer's Office (cash mgt.)	11,272	4,585	3,974	2,952	22,783	13,970	**26,150**
City Council	37,787	22,758	13,311	16,746	90,602	50,960	**104,000**
Mayor	326	326	326	-	978	3,070	**1,120**
Community Affairs	1,012	632	379	411	2,434	1,000	**2,790**
Total Admin Fees	$ 649,538	$ 306,260	$ 101,615	$ 32,450	$ 1,089,863	$ 1,300,500	**$ 1,251,000**
Tax or Fee Authorized							**-**
Payment in Lieu-of-Taxes (General Fund)	$ 398,485	$ 306,525	$ 109,785	$ -	$ 814,795	$ 831,092	**1,126,697**
Franchise Fees (General Fund)	2,810,068	1,374,769	350,175	-	4,535,012	5,622,628	**6,147,049**
Sub Total	$ 3,208,553	$ 1,681,294	$ 459,960	$ -	$ 5,349,807	$ 6,453,720	**$ 7,273,746**
Internal Service Fund Services							
Fleet Mgt. Services	$ 1,029,585	$ 568,448	$ 223,731	$ -	$ 1,821,764	$ 2,042,040	**$ 2,007,000**
City Data Processing (IMS)	912,977	381,234	294,929	1,117	1,590,257	933,300	**1,539,000**
Telephone Charges	-	-	-	-	-	94,248	**8,400**
Risk Mgt. Admininstrative Fees (Gov. Immunity)	111,519	44,317	3,048	-	158,884	246,381	**216,550**
Risk Management Premiums & Charges	632,362	258,886	54,937	-	946,185	1,495,502	**1,251,803**
Sub Total	$ 2,686,442	$ 1,252,885	$ 576,645	$ 1,117	$ 4,517,090	$ 4,811,471	**5,022,753**
Special Associated Charges (indirect benefit)							
OneSolution Maintenance (network financial syste	$ -	$ -	$ -	$ -	$ -	$ 111,180	**89,000**
Street Sweeping	-	-	819,605	-	819,605	835,997	**819,605**
Neighborhood Clean-up	-	-	-	-	-	118,000	**-**
Emergency Management	-	-	-	-	-	30,000	**-**
Tracy Aviary Stormwater Education Cost	-	-	154,350	-	154,350	75,000	**75,000**
Sub Total	$ -	$ -	$ 973,955	$ -	$ 973,955	$ 1,170,177	**$ 983,605**
TOTAL FEES, TAXES AND CHARGES	$ 6,544,533	$ 3,240,440	$ 2,112,175	$ 33,567	$ 11,930,715	$ 13,735,868	**$ 14,531,104**

Public Utilities Proposed Consulting Studies for FY 2019-2020

Division	Cost Center	Study or Project Description	Lighting	Water	Sewer	Storm	Total
Administration	5103000	5-Year Emergency Preparedeness Plan		12,000			12,000
Administration	5100200	Well Study		20,000			20,000
Administration	5103000	Ongoing Environmental Assessments for PU facilities		20,000			20,000
Administration	5103400	Standards development		20,000			20,000
Administration	5103600	Water Conservation		50,000			50,000
Administration	5100200	Central Wasatch Commission		200,000			200,000
Engineering	4848000	Street Light Master Plan	90,000				90,000
Engineering	5210400	Basin Inflow Testing			300,000		300,000
Engineering	5210400	Jacobs Program Support			350,000		350,000
Engineering	5310300	Jacobs Program Support				50,000	50,000
Engineering	5310300	Storm Water Master Plan				700,000	700,000
Engineering	5101300	Water loss study		100,000			100,000
Engineering	5101300	AMP for Storage Reservors		135,000			135,000
Engineering	5101300	Campus study		350,000			350,000
Engineering	5101300	Jacobs Program Support		400,000			400,000
Engineering	5101300	Water Master Plan		500,000			500,000
Finance	5211700	Energy Retro-Commissioning Study			55,000		55,000
Finance	5310500	Energy Retro-Commissioning Study				35,000	35,000
Finance	5103200	Adjudication and other administrative needs.		500,000			500,000
GIS	5101600	Water Data Tracking Software & Consultant		250,000			250,000
Maintenance	5310200	Clean parts of Irrigation system				25,000	25,000
Maintenance	5100100	Geotech consultants		50,000			50,000
Maintenance	5100100	Consulting Project for Canals		60,000			60,000
Maintenance	5100300	Consultants for Well Issues		100,000			100,000
Reclamation	5212400	Study to identify inhibiting-causing pollutants at the WRF			40,000		40,000
Reclamation	5212400	Study to evaluate and determine updated local wastewater discharge limits			60,000		60,000
Reclamation	5212400	Study to evaluate and determine updated sewer rate classifications			250,000		250,000
Water Quality	5310700	Consultant to address MS4 Audit/QAQC				20,000	20,000
Water Quality	5310700	TMDL Load Allocation				50,000	50,000
Water Quality	5100600	Misc Needs		15,000			15,000
Water Quality	5100600	PR Campaign additional Funds		30,000			30,000
Water Quality	5101800	Public Relations		30,000			30,000
Water Quality	5101800	Utah State University Canal Water Quality Analysis		32,000			32,000
Water Quality	5101800	Process Controls		35,000			35,000
Water Quality	5100600	Watershed Plan		120,000			120,000
			$ 90,000	**$ 3,029,000**	**$ 1,055,000**	**$ 880,000**	**$ 5,054,000**

Water Utility- Budget Summary and Cash Flow

WATER UTILITY
ENTERPRISE FUND
BUDGET SUMMARY
Fiscal Years 2020-22

SOURCES	ACTUAL 2017-18	AMENDED BUDGET 2018-19	PROJECTED ACTUAL 2018-19	Rate Increase 5% **PROPOSED BUDGET 2019-20**	Rate Increase 5% **FORECAST BUDGET 2020-21**	Rate Increase 5% **FORECAST BUDGET 2021-22**
REVENUES						
METERED SALES	$69,351,147	$73,289,346	$72,125,193	**$75,731,453**	$79,784,026	$83,773,227
INTEREST INCOME	831,749	375,000	375,000	**229,000**	92,000	89,000
OTHER REVENUES	4,240,466	3,037,985	3,037,985	**3,063,157**	3,063,157	3,063,157
TOTAL REVENUES	$74,423,362	$76,702,331	$75,538,178	**$79,023,610**	$82,939,183	$86,925,384
OTHER SOURCES						
GRANTS & OTHER RELATED REVENUES	$1,804,748	$1,205,000	$1,205,000	**$1,205,000**	$1,205,000	$1,205,000
IMPACT FEES	1,520,259	500,000	500,000	**1,000,000**	1,000,000	1,000,000
OTHER SOURCES	115,307	50,000	50,000	**50,000**	50,000	50,000
BOND PROCEEDS	-	-	-	**35,196,000**	42,235,000	26,146,000
T O T A L OTHER SOURCES	$3,440,314	$1,755,000	$1,755,000	**$37,451,000**	$44,490,000	$28,401,000
T O T A L SOURCES	$77,863,676	$78,457,331	$77,293,178	**$116,474,610**	$127,429,183	$115,326,384
EXPENSES & OTHER USES						
EXPENDITURES						
PERSONNEL SERVICES	$19,852,264	$22,069,746	$22,069,746	**23,387,302**	$24,322,796	$25,295,713
OPERATING & MAINTENANCE	3,392,135	4,233,777	4,233,777	**4,415,380**	4,492,588	4,582,441
TRAVEL & TRAINING	45,173	146,408	146,408	**167,083**	170,426	173,834
UTILITIES	2,397,853	2,854,647	2,854,647	**2,784,962**	2,840,660	2,897,473
TECHNICAL SERVICES	3,657,447	8,726,160	8,726,160	**7,543,867**	6,490,344	6,390,712
DATA PROCESSING	1,065,047	967,347	967,347	**1,177,347**	1,200,895	1,224,911
FLEET MAINTENANCE	1,029,720	1,250,000	1,250,000	**1,250,000**	1,275,000	1,300,500
ADMINISTRATIVE SERVICE FEE	649,538	800,000	800,000	**800,000**	816,000	832,320
PAYMENT IN LIEU OF TAXES	398,485	476,000	476,000	**365,000**	372,300	379,746
METRO. WATER PURCH & TREAT	15,528,950	15,994,818	15,994,818	**16,474,663**	16,968,903	17,477,971
METRO ASSESSMENT (CAPITAL)	7,021,892	7,021,892	7,021,892	**7,021,892**	7,021,892	7,021,892
RISK MANAGEMENT	952,332	1,088,550	1,088,550	**1,123,187**	1,145,651	1,168,563
TRANSFERS TO GENERAL FUND	0	85,000	85,000	**85,000**	86,700	88,434
OTHER CHARGES AND SERVICES	(1,032,212)	(359,811)	(359,811)	**(319,913)**	(328,020)	(334,579)
TOTAL EXPENDITURES	$54,958,624	$65,354,534	$65,354,534	**$66,275,770**	$66,876,135	$68,499,931
OTHER USES						
CAPITAL OUTLAY	$5,148,158	$4,682,304	$4,898,838	**$2,509,447**	$2,930,000	$2,930,000
CAPITAL IMPROVEMENT BUDGET	18,041,425	51,641,293	24,629,211	**59,255,100**	53,501,500	38,542,400
COST OF DEBT ISSUANCE	1,900	0	0	**196,000**	235,000	146,000
DEBT SERVICES	967,961	1,117,000	1,117,000	**1,585,000**	3,043,000	4,600,000
T O T A L OTHER USES	$24,159,444	$57,440,597	$30,645,049	**$63,545,547**	$59,709,500	$46,218,400
T O T A L USES	$79,118,068	$122,795,131	$95,999,583	**$129,821,317**	$126,585,635	$114,718,331
EXCESS REVENUE AND OTHER SOURCES OVER (UNDER) USES	($1,254,392)	($44,337,800)	($18,706,405)	**($13,346,707)**	$843,548	$608,053
OPERATING CASH BALANCES						
BEGINNING JULY 1	$47,048,055	$45,793,663	$45,793,663	**$27,087,258**	$13,740,551	$14,584,099
ENDING JUNE 30	$45,793,663	$1,455,863	$27,087,258	**$13,740,551**	$14,584,099	$15,192,152
Cash Reserve Ratio	83%	2%	41%	**21%**	22%	22%

Cash reserve goal above 10%

WATER UTILITY
Cash Flow
FY 2020 Budget
and FY 2021-2024 Budget Forecast

Rates +5% FY20 - FY23 +6% FY24
Bonds Total $169M, $35M,$42M,$26M,$29M,$15M ...
CIP 100%, New Bond Pmts thru FY 24: $21.3

	ACTUAL YEAR 2017-2018	PROJECTED YEAR 2018-2019	BUDGET YEAR 2019-2020	BUDGET YEAR 2020-2021	BUDGET YEAR 2021-2022	BUDGET YEAR 2022-2023	BUDGET YEAR 2023-2024
WATER SALES	69,351,147	72,125,193	75,731,453	79,784,026	83,773,227	87,961,888	93,239,601
OTHER INCOME	4,240,466	3,037,985	3,063,157	3,063,157	3,063,157	3,063,157	3,063,157
INTEREST INCOME	831,749	375,000	229,000	92,000	89,000	90,000	93,000
OPERATING INCOME	74,423,362	75,538,178	79,023,610	82,939,183	86,925,384	91,115,045	96,395,758
METROPOLITAN WATER ASSESSMENT	(7,021,892)	(7,021,892)	(7,021,892)	(7,021,892)	(7,021,892)	(7,021,892)	(7,021,892)
METROPOLITAN WATER PURCHASES	(15,528,950)	(15,994,819)	(16,474,663)	(16,968,903)	(17,477,971)	(18,002,310)	(18,542,380)
OPERATING EXPENDITURES	(32,407,782)	(42,337,823)	(42,779,215)	(42,885,337)	(44,000,060)	(45,120,974)	(46,539,544)
NET INCOME EXCLUDING DEP.	19,464,738	10,183,644	12,747,840	16,063,051	18,425,461	20,969,869	24,291,942
NET BOND PROCEEDS			35,000,000	42,000,000	26,000,000	29,000,000	15,000,000
BIC Borrowed			196,000	235,000	146,000	162,000	84,000
BIC Paid			(196,000)	(235,000)	(146,000)	(162,000)	(84,000)
SHORT TERM FINANCING							
IMPACT FEES	1,520,259	500,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000
OTHER CONTRIBUTIONS	1,920,055	1,255,000	1,255,000	1,255,000	1,255,000	1,255,000	1,255,000
CAPITAL OUTLAY	(5,148,158)	(4,308,101)	(1,009,447)	(1,430,000)	(1,430,000)	(1,430,000)	(1,430,000)
WATERSHED PURCHASES	0	(590,737)	(1,500,000)	(1,500,000)	(1,500,000)	(1,500,000)	(1,500,000)
DEBT SERVICE	(969,861)	(1,117,000)	(1,127,000)	(1,085,000)	(1,090,000)	(1,091,000)	(1,040,000)
NEW DEBT SERVICE	0	0	(458,000)	(1,958,000)	(3,510,000)	(4,730,000)	(6,625,000)
OTHER INCOME & EXPENSE	(2,677,705)	(4,260,838)	33,160,553	38,282,000	20,725,000	22,504,000	6,660,000
GENERATED FOR CAPITAL	16,787,033	5,922,806	45,908,393	54,345,051	39,150,461	43,473,869	30,951,942
CAPITAL IMPROVEMENTS	**(18,041,425)**	**(24,629,211)**	**(59,255,100)**	**(53,501,500)**	**(38,542,400)**	**(42,350,000)**	**(29,914,000)**
BEGINING CASH BALANCE	47,048,055	45,793,663	27,087,258	13,740,551	14,584,102	15,192,163	16,316,032
CASH INCREASE/(DECREASE)	(1,254,392)	(18,706,405)	(13,346,707)	843,551	608,061	1,123,869	1,037,942
ENDING BALANCES	45,793,663	27,087,258	13,740,551	14,584,102	15,192,163	16,316,032	17,353,974
RESTRICTED / RESERVED CASH	(23,928,611)	(8,952,141)	(8,952,141)	(8,952,141)	(8,952,141)	(8,952,141)	(8,952,141)
AVAILABLE ENDING BALANCE	21,865,052	18,135,117	4,788,410	5,631,961	6,240,022	7,363,891	8,401,833
S&P COVERAGE (INCLUDES MWA AS DEBT SERVICE)		**2.11**	2.30	**2**	**2.19**	**2.18**	**2.13**
DEBT SERVICE COVERAGE	**20.07**	**9.12**	**8.04**	**5**	**4.01**	**3.60**	**3.17**
RATE CHANGE	**4%**	**4%**	**5%**	**5%**	**5%**	**5%**	**6%**
Cash Reserve Ratio (Total Cash)	**83%**	**41%**	**21%**	**22%**	**22%**	**23%**	**24%**
DEBT SERVICE % OF GROSS OPERATING REVENUE	1.30%	1.45%	1.95%	3.57%	5.16%	6.23%	7.77%
MONTHLY RESIDENTIAL BILL (255 ccf annually/12 mos.)	44.83	46.60	46.41	48.74	51.18	53.74	56.97

WATER UTILITY CIP BUDGET
Five Year Projected Budget FY2020-2024

COST CENTER	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	CRITICALITY RATING	CONDITION RATING	PAST YEAR SPENT 2018-19 (Calc'd from P6)	BUDGET YEAR 2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
51-01301-	2720.10		**MAINTENANCE & REPAIR SHOPS**									
01401		2015-0460	DISTRIBUTION AND ELECTRICAL BARN	4	4	0						850,000
			CAMPUS	5	5					15,000,000	10,000,000	
03201	512185		FUEL PUMP AWNINGS	5	0	0				250,000		
						$ -	$ -	$ -	$ -	$ 15,250,000	$ 10,000,000	$ 850,000
51-01301-	2720.30		**TREATMENT PLANTS**									
			CITY CREEK									
00701	5122628	2015-0178	DRYING BED PIPELINES	5	5	723,637						
00701	5122665	2015-0685	CCWTP CONTINGENCY PROJECTS	5	5	0						
00701	512260079	2017-2043	TREATMENT PLANT UPGRADES (PENDING 2019 ASSESSMENT RESULTS; DESIGN AND CONST	5	5	326,088	1,500,000	1,500,000	1,500,000	1,500,000	1,500,000	
00701	5122674		HYPOGENERATOR DESIGN	3	0	0						
00701		2015-0177	CITY CREEK - ACTUATORS/SCADA (MULTIPLE LOCATIONS)	3	3	0						
00701		2015-0182	IMPLEMENTATION OF SCADA MASTER PLAN	3	3	0						
00701		2015-0447	CLARIFIER UPGRADE	3	3	0						
00701		2015-0702	ELECTRICAL SYSTEM ASSESSMENT AND UPGRADE	5	4	0						
00701		2016-0871	SEISMIC UPGRADE FILTER BUILDIING STUDY	5	4	0						
00701		2016-0876	PRESSURE DIFFERENTIAL TRANSMITTERS	3	4	0						
00701		2016-0880	CREEK CHANNEL	3	4	0						
00701		2016-0881	FILTER/FLUORIDE BUILDING GATE	3	4	0						
00701		2017-1297	PUMP BACK SYSTEM	2	0	0						
00701		2018-1098	CITY CREEK FILTER MEDIA REPLACEMENT	4	5	0						
00701		2019-1001	CITY CREEK WTP UPGRADES - PHASE 2	5	3	0						30,000,000
00701	512260078	2016-0879	BACKWASH TANK SEISMIC UPGRADE AND RETAINING WALL	5	4	62,473						
00701	512260077	2017-2042	CITY CREEK CCTV SYSTEM UPGRADE	5	4	18,000						
00701	5122676		COAGULATION BUILDING DEMOLITION			101,669						
						$ 1,231,866	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 30,000,000
			PARLEY'S									
00801	5124561	2015-0686	PWTP CONTINGENCY PROJECTS	5	5	0						
00801	512450070	2015-0688	FILTER ASSESSMENT AND FILTER #5 REPAIR	5	5	75,000						
00801	5124525	2015-0203	REPLACE SLUDGE COLLECTION SYSTEM FLIGHTS, CHAINS, AND DRIVES	5	5	1,898,136						
00801	5124506	2015-0201	LABORATORY UPGRADE (BUILD)	5	4	1,284,460						
00801	512450068	2015-0701	PLANT DESIGN AND UPGRADES	5	4	205,880	1,500,000	10,000,000	2,000,000	2,000,000	2,000,000	
00801	5124532		REPLACEMENT OF CHEMICAL FEED PUMPS PARLEY'S CANYON			0						
00801	512450069	2015-0594	BACK-UP WATER SUPPLY FOR HIGH PRESSURE TANK	5	3	0						
00801		2015-0695	RELOCATE POTASSIUM PERMANGANATE FEED SYSTEM	4	4	0						
00801	5124526	2015-0455	INFLUENT CONTROL BOX	4	3	0						
00801	512450066	2016-0867	ROOF REPLACEMENT	4	5	0						
00801	512450067	2016-0874	REBUILD/REPLACE FLOC-SED BASIN VENTILATION SYSTEM	2	5	0						
00801		2015-0450	PRECURSOR - TASTE AND ODOR CONTROL	3	3	0						
00801	5124504	2015-0449	SLUDGE BEDS - PIPING AND VALVES	2	3	0						
00801		2015-0197	ELECTRICAL CONDUITS/PAVING TO BLOW-OFF BOX/ASPHALT EAST AND SOUTH OF FA(	3	3	0						
00801		2015-0204	REPLACE FLOCCULATORS	4	4	0						
00801		2015-0448	SCADA MASTER PLAN IMPLEMENTATION	4	4	0						
00801		2015-0452	NEW I/O AND PLC	2	1	0						
00801		2017-2005	PROCESS UPGRADES (FROM SED BASIN PREDESIGN)	1	0	0						
00801		2017-2006	VERTICAL FLOCCULATOR INSTALLATION	5	3	0						
00801	512450072	2016-1280	PLANT LIGHTING	5	4	30,000						
00801	512450073		SODIUM HYPOCHLORITE STORAGE TANK FOR PWTP AND BCWTP			40,000	300,000					
00801		2018-1037	PARLEYS DIVERSION SCREEN PROJECT	4	0	0	250,000	1,250,000				1,500,000

WATER UTILITY CIP BUDGET
Five Year Projected Budget FY2020-2024

COST CENTER	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	CRITICALITY RATING	CONDITION RATING	PAST YEAR SPENT 2018-19 (Calc'd from P6)	BUDGET YEAR 2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
00801		2018-1095	PARLEYS FINISHED WATER RESERVOIR	3	0	0						20,000,000
00801		2018-1094	NEW PARLEYS WATER TREATMENT PLANT	5	4	0						136,500,000
						$ 3,533,477	$ 2,050,000	$ 11,250,000	$ 2,000,000	$ 2,000,000	$ 2,000,000	$ 158,000,000
			BIG COTTONWOOD									
00901	51262759	2015-0186	SCADA MASTER PLAN/OPERATOR STATION UPGRADE IMPLEMENTATION			0	300,000					
00901	512627462	2015-0684	BCWTP CONTINGENCY PROJECTS	5	5	0						
00901	512627460	2015-0192	SEDIMENTATION BASIN REBUILD	5	5	829,641						
00901		2019-1002	BIG COTTONWOOD WTP REBUILD - PHASE 1	5	4	0	2,500,000	5,000,000	2,500,000	2,000,000	2,000,000	80,000,000
00901		2015-0191	BIG COTTONWOOD - ASPHALT LOWER-END OF BUILDING TO DRYING BEDS	5	5	0						
00901	512627469	2017-2049	RELOCATION AND HOUSING OF SWITCHGEAR	5	5	0						
00901		2015-0188	FINISHED WATER FLOW METER/FINISHED WATER SAMPLE POINT	5	4	0						
00901		2016-1236	90 FOOT CHANNEL UPGRADES	4	4	0						
00901		2015-0190	REPLACE FLOCCULATION SHAFT DRIVES AND EQUIPMENT	4	4	0						150,000
00901		2015-0698	REROOF COAGULATION BUILDING	4	3	0						100,000
00901		2018-1030	BIG COTTONWOOD SLUDGE SYSTEM UPGRADE	5	4	0						1,500,000
00901		2018-1043	BIG COTTONWOOD WTP REBUILD - PHASE 2	5	4	0						75,000,000
00901		2015-0189	2-10 MILLION GALLON FINISHED WATER STORAGE RESERVOIR	3	3	0						
00901	512627470	2015-0713	HVAC UPGRADES IN FILTER ROOM	5	5	45,044						
00901	512627457	2016-1279	PLANT LIGHTING	5	4	30,000						
00901		2018-1099	FILTER ASSESSMENT AND IMPROVEMENTS	5	4	0	1,500,000					
						$ 904,685	$ 4,300,000	$ 5,000,000	$ 2,500,000	$ 2,000,000	$ 2,000,000	$ 156,750,000
			TOTAL TREATMENT PLANTS			$ 5,670,028	$ 7,850,000	$ 17,750,000	$ 6,000,000	$ 5,500,000	$ 5,500,000	$ 344,750,000
51-01301-	2720.35		**PUMPING PLANTS AND PUMP HOUSES**									
01301	513416331		EAST BENCH PUMP STATION - FULL BACKUP POWER	5	5	623,996						
01301		2016-1174	5TH AVE AND U ST PUMP STATION BACKUP POWER	5	5	0	400,000					
01301	513416364	2016-1282	BONNEVILLE AND EAST BENCH PUMP STATION - PUMP UPGRADES	5	5	24,000						
01301	513416365	2015-0514	NORTH BENCH PUMP STATION ROOF	4	5	27,494						
01301	513505271	2015-0378	UPLAND DR PROJECT	4	5	0	800,000					
01301	513800033	2015-0555	3900 SOUTH BIRCH DRIVE VALVE VAULT	4	4	8,142						
01301	513416359	2016-0888	3900 SOUTH PUMP STATION	4	4	313,408	30,000	3,600,000	7,200,000			
01301	513416366	2015-0531	GOLDEN HILLS PUMP STATION	3	5	90,000	60,000					
01301	513416367	2016-1208	5TH AND U PUMP STATION IMPROVEMENTS	4	4	12,981	275,000					
01301	513416361	2015-0563	OAKHILLS PUMP STATION - MCC - VFD - PUMP UPGRADE	3	3	0		550,000				
01301		2016-0937	ENSIGN DOWNS PS VFD	3	3	0			20,000			
01301	513416336	2015-0428	MP 3.12 B - 7800 SOUTH AUXILIARY POWER	3	3	0			305,000			
01301		2016-1179	300 EAST PUMP STATION BACKUP POWER	3	3	0			400,000			
01301		2016-1180	3300 SOUTH BOOSTER PUMP STATION BACKUP POWER	3	3	0			400,000			
01301		2016-1181	KENTON DRIVE PUMP STATION BACKUP POWER	3	3	0			400,000			
01301		2016-1183	VIRGINIA AND MILLCREEK PUMP STATION BACKUP POWER	3	3	0				400,000		
01301		2016-1184	EASTWOOD PUMP STATION BACKUP POWER	3	3	0				400,000		
01301		2016-1185	MILLCREEK PUMP STATION BACKUP POWER	3	3	0				400,000		
01301		2016-1186	39TH AND BIRCH PUMP STATION BACKUP POWER	3	3	0				400,000		
01301		2016-1187	CANYON COVE PUMP STATION BACKUP POWER	3	3	0					400,000	
01301		2016-1188	7800 SOUTH PUMP STATION BACKUP POWER	3	3	0					400,000	
01301		2016-1189	GOLDEN HILLS PUMP STATION BACKUP POWER	3	3	0					400,000	
01301		2016-1190	CARRIGAN COVE PUMP STATION BACKUP POWER	3	3	0					400,000	
01301		2016-1173	NORTH BENCH PUMP STATION BACKUP POWER	3	3	0						400,000
01301		2016-1175	UNIVERSITY PUMP STATION BACKUP POWER	3	3	0						400,000

WATER UTILITY CIP BUDGET
Five Year Projected Budget FY2020-2024

COST CENTER	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	CRITICALITY RATING	CONDITION RATING	PAST YEAR SPENT 2018-19 (Calc'd from P6)	BUDGET YEAR 2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
01301		2016-1176	RESEARCH PARK PUMP STATION BACKUP POWER	3	3	0						400,000
01301		2016-1177	OAK HILLS PUMP STATION BACKUP POWER	3	3	0						400,000
01301		2016-1178	BONNEVILLE PUMP STATION BACKUP POWER	3	3	0						400,000
01301		2016-1191	3900 SOUTH BOOSTER PUMP STATION BACKUP POWER	3	3	0						400,000
01301		2016-1192	6200 SOUTH IRRIGATION PUMP STATION BACKUP POWER	3	3	0						400,000
01301		2016-1193	EMIGRATION PUMP STATION BACKUP POWER	3	3	0						400,000
01301		2016-1223	5TH AVE AND U ST PUMP STATION VFD'S	3	3	0						200,000
01301		2016-1224	ARLINGTON HILLS PUMP STATION VFD'S	3	3	0						200,000
01301		2016-1225	NORTH BENCH PUMP STATION VFD'S	3	3	0					200,000	
01301		2016-1226	5TH AVE AND U ST PUMP STATION PIPING	3	3	0						200,000
01301		2017-2009	REPAIR AND LINE OF UNIVERSITY DRAIN LINE	2	3	0						10,000
01301		2015-0517	4500 SOUTH PUMP STATION BLACK TOP	1	3	0						25,000
01301		2015-0522	RECURRING PUMP STATION REPAIR FUND	3	0	0						50,000
01301	513416329	2015-0169	UV UPGRADE 6200 SOUTH PUMP STATION	1	2	0						300,000
01301		2016-1194	ENSIGN DOWNS PUMP STATION BACKUP POWER	3	0	0						400,000
01301		2015-0172	MP 3.8C - VICTORY ROAD - ENSIGN DOWNS PHASE II - PROPERTY PURCHASE - IF	4	0	0						500,000
01301		2015-0173	4500 SOUTH PUMP STATION (BACK UP)	5	0	0						1,500,000
						$ 1,100,021	$ 1,565,000	$ 4,150,000	$ 8,725,000	$ 1,600,000	$ 1,800,000	$ 6,585,000
51-01301-	2730.02		**CULVERTS FLUMES & BRIDGES**									
01301	5129264		JSL CANAL CONDUIT REPLACEMENT - SUGARHOUSE	5	5	67,976	1,000,000					
01301	513000045	2016-1166	SUGARHOUSE WELL SPLASH PAD	5	5	59,889	150,000					150,000
01301	512900272	2015-0432	VARIOUS CANAL IMPROVEMENTS	5	5	25,000	25,000	25,000	25,000	25,000	25,000	
01301	512900273	2016-0737	IRRIGATION SCADA IMPROVEMENTS	5	5	20,000	50,000	20,000	20,000	20,000	20,000	
01301		2016-0816	ROCKHOUSE DUMP - INTAKE IMPROVEMENT	5	4	0		78,500				
01301	513000034	2016-0858	FLUME FROM DOUBLE BARRELS TO RAILROAD TRACKS	4	4	21,512			1,250,000	1,250,000		
01301	5129246	2015-0158	REPLACE FLUME/AUTO DUMP AND JSL CANAL ENCLOSURE @ MILLCREEK	4	4	0	100,000	468,000				
01301	512900274	2017-2076	HEADGATE REHABILITATION 18/19	4	4	20,000	20,000	20,000	20,000	20,000	20,000	
01301	513000026	2015-0161	E JORDAN TOWER - IMPROVED ACCESS	3	5	20,000		150,000				
01301		2016-1167	6200 SOUTH LIFT STATION WEIR PROTECTION	3	5	0	60,000					
01301	5129231	2015-0152	JSL CANAL - 1750 S EMIGRATION DIVERSION STRUCTURE REBUILD	4	3	0				50,000	290,000	
01301	5129233	2015-0604	JSL 3800 S REHAB FLOOR AND LEAKAGE	3	4	0			18,000			
01301	5129251	2015-0151	JSL ENCLOSURE FROM 1300 EAST TO MILLCREEK	3	3	0						997,000
01301		2015-0168	IMPROVEMENTS TO JSL DUMP AT I-80	3	3	0						11,000
01301	5129235	2015-0606	JSL 4500 SOUTH TO OSAGE ORANGE DRIVE – CANAL BANK HYDRAULICS	3	3	0				20,000		
01301	5129249	2015-0149	NEW IRRIGATION CONDUIT ON HARVARD AVENUE	4	0	0			50,000		402,000	
01301	513000038	2016-0865	OIL SEPARATORS AND DRAINAGE SYSTEM FOR THE ARTESIAN SHOP	4	0	37,500		600,000				
01301		2016-1165	LOW FLOW CHANNEL AT SPENCER'S POND (BIG COTTONWOOD CREEK)	4	0	0					300,000	
01301		2016-1284	1100 EAST DIVERSION STRUCTURE AT WILLINGTON	4	0	0						50,000
01301	5129232	2015-0602	JSL CANAL – MODIFY BIG SPILL TO HANDLE TEMPORARY PUMP	2	2	0					82,000	
01301		2016-1287	STUDY ON WELLS AT WALKER LANE AND FOUNTAIN BEAU	1	3	0						1,000,000
01301		2016-0749	J&SL DIVERSION STRUCTURE AT 2700 SOUTH	2	0	0						350,000
01301		2016-1286	3000 EAST WELL FOR WATER DELIVERIES	2	0	0						2,000,000
01301	5129242	2015-0153	PIPING DITCH ON JSL, OSAGE ORANGE AVENUE TO LINCOLN LANE	1	0	0						175,000
01301		2015-0160	DESPAIN IRRIGATION SYSTEM IMPROVEMENTS	3	3	0						17,000
01301		2015-0603	JSL CANAL/JORDAN RIVER STABILIZATION AT EAST JORDAN DUMP	4	4	0						406,000
01301		2018-1019	14600 SO. CANAL OVER FLOW STRUTURE	3	3	0						500,000
01301		2018-1080	3900SO STORM DRAIN OVER FLOW	2	4	0				50,000	250,000	
01301		2018-1082	LITTLE TANNER PIPE PROJECT	2	0	0						50,000
			REHABILITATION/REPLACEMENT OF JSL IN CITY LIMITS				50,000	50,000	50,000	50,000	50,000	
						$ 271,878	$ 1,455,000	$ 1,411,500	$ 1,433,000	$ 1,485,000	$ 1,439,000	$ 5,706,000

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51-01301-	2730.04		**DEEP PUMP WELLS**									
01301	5132245	2015-0429	WELL ASSESSMENT AND UPGRADES	5	5	100,000	200,000	200,000	200,000	200,000	200,000	
01301	5132270	2015-0430	WELL BUILDING STRUCTURE UPGRADES	5	5	100,000	100,000	100,000	100,000	100,000	100,000	
01301	5132268	2015-0213	MP3.4 - 4TH AVENUE WELL ELECTRICAL IMPROVEMENTS	5	5	393,481	3,000,000					
01301	5132269	2015-0212	MP3.4 - 4TH AVENUE WELL/BRICK TANK IMPROVEMENTS	5	5	71,155						
01301	51322336	2015-0171	WELL TREATMENT PROJECT - 1500 EAST WELL	4	4	100,000	100,000					
01301		2016-0820	DYERS INN	4	4	0			550,000			
01301		2017-2071	DYER'S INN WELL FLUSH LINE	4	4	0			100,000			
01301		2016-0911	1300 E WELL CHLORINATION	3	4	0						400,000
01301		2015-0408	1300 EAST WELL FLUSH LINE	2	2	0			95,000			
01301	5132255	2015-0571	ARTESIAN WELL 2 REHAB	4	0	0						250,000
01301	5132249	2015-0565	19TH AND 27TH SOUTH WELL - VFD	3	0	0						60,000
01301	5132246	2015-0570	TREATMENT OF PCE AT WELLS	3	0	0						12,000,000
01301	5132241	2015-0569	RED BUTTE	2	0	0			2,500,000	60,000		2,500,000
01301	513223419		MT OLIVET IRRIGATION FEASIBLITY STUDY			3,464						
01301		2018-1038	4TH AVENUE WELL INSPECTION	4	2	0						40,000
01301		2018-1091	VAN WINKLE PROPERTY FENCE	1	5	0					20,000	
						$ 768,100	$ 3,400,000	$ 300,000	$ 3,545,000	$ 360,000	$ 320,000	$ 15,250,000
51-01301-	2730.06		**STORAGE RESERVOIRS**									
01301	5134506	2017-1290	MOUNTAIN DELL RESERVOIR SEDIMENT SAMPLING AND BASIN PRE DESIGN	5	4	1,588						
01301	5134510		PARLEY'S DIVERSION STRUCTURE - IMPROVE BOOM DEPLOYMENT LOCATION	5	3	5,000						
01301	5134476		CHEVRON OIL SPILL PROTECTION PROJECT			3,000						
01301	5134458	2015-0155	REHABILITATION OF MOUNTAIN DELL DAM	5	4	853,333	2,165,000					
01301	5134455	2015-0167	RED PINE DAM REHABILITATION	5	4	30,000						484,000
01301	5134467	2015-0154	MOUNTAIN DELL RESERVOIR - BYPASS PIPE LITTLE DELL TO PARLEY'S	5	0	1,003,384						
01301	512450071	2017-2094	NEW ACTUATORS FOR THE PARLEYS CREEK DIVERSION STRUCTURE	5	0	17,714						
01301	5134468	2015-0607	LITTLE DELL RESTORE PARLEY'S DIVERSION EXTERIOR COATING	4	4	4,725						
01301	5124512	2015-0209	REPLACE VALVES ON MT. DELL DAM	4	4	0						320,000
01301	512700001	2017-2080	REABILITATION OF THE LAKE MARY GAUGE	3	5	1,161						
01301	512700005	2016-1272	CECRET DAM REHABILITATION - DESIGN	4	3	32,525						2,000,000
01301	512700002	2017-2082	REPAIRS TO TWIN LAKES DAM GAUGE	3	4	1,545						
01301	512700003	2017-2079	REPAIRS AND IMPROVEMENTS TO RED BUTTTE DAM ROAD	3	4	30,000						
01301	5134478	2015-0164	LITTLE DELL DAM - INSTALL NEW DRAINS ON THE PORTAL	3	3	0						27,000
01301		2016-1278	SECURITY CAMERAS AT LITTLE DELL	3	3	0						50,000
01301	5134457	2015-0166	NEW STAFF GAGE AT LITTLE DELL DAM	3	3	0						153,000
01301	5124509	2015-0451	STAIRS MT DELL DAM	2	3	0						75,000
01301		2015-0208	CONDUIT FROM DAM TO OLD ICB TO PLANT	2	2	0						20,000
01301	5134466	2015-0156	PARLEY'S CANYON HYDROPOWER PROJECT	1	0	0	100,000	900,000	200,000			
01301	512700006		LITTLE DELL PENSTOCK: PHASE 2			1,000,054						
01301		2018-1034	SPILL PROTECTION PROJECT - I-80 AT LAMB'S CANYON	5	0	0						240,000
01301		2018-1100	LAKE MARY DAM CREST REHABILITATION	5	5	0	20,000					100,000
01301		2018-1101	TWIN LAKES DAM GAUGE RELOCATION	3	4	0						20,000
01301		2018-1102	TWIN LAKE AND LAKE MARY OUTLET CHANNEL IMPROVEMENTS	5	5	0	15,000	50,000	50,000			
01301		2018-1103	PARLEYS CANYON CONDUIT AND FIBER INSTALLATION	4	0	0	100,000					100,000
01301		2018-1104	TWIN LAKES DAM DRAIN CLEANOUT INSTALLATION	4	5	0	40,000					40,000
01301		2018-1105	TWIN LAKES AND LAKE MARY LOG BOOMS	3	5	0						10,000
01301		2018-1106	MOUNTAIN DELL DAM SPILLWAY REHABILITATION	5	4	0	100,000					100,000
01301		2018-1107	LITTLE DELL DAM RODENT ERADICATION	4	4	0	50,000					30,000
01301		2018-1108	LITTLE DELL DAM STAFF GAUGE	3	0	0						175,000
01301		2018-1109	CECRET LAKE FLOW METER AND TELEMETRY	4	0	0						60,000
						$ 2,984,028	$ 2,590,000	$ 950,000	$ 250,000	$ -	$ -	$ 4,004,000

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51-01301-	2730.07		**DISTRIBUTION RESERVOIRS**									
01301	513444163	2017-2060	NEFF'S TANK OVERFLOW DRAIN	5	5	81,064						
01301	513444164	2017-2067	MARCUS RESERVOIR TANK UPGRADES	5	5	7,500						1,000,000
01301	513444161	2017-2074	EASTWOOD NORTH - INTERIOR COATING	5	5	128,632						
01301	513444162	2015-0527	FERGUSON TANK UPGRADE	5	5	14,511	150,000					
01301	513444166	2015-0573	AM - TANK AND RESERVOIR INSPECTIONS AND REPAIRS	5	5	100,000	100,000	100,000	100,000	100,000	100,000	100,000
01301	513444165	2015-0409	MOUNT OLYMPUS TANKS DRAIN/OVERFLOW STRUCTURE	5	4	72,580						
01301	5134507	2016-1171	FORT DOUGLAS IMPROVEMENTS/EXPANSION	5	4	163,424		4,000,000				1,500,000
01301	513444159	2015-0174	MILITARY RESERVOIR REPAIR	5	3	0						11,020,000
01301		2015-0406	EMIGRATION TUNNEL POWER	4	4	0						45,000
01301	513444168	2017-2111	TANNER RESERVOIR ROOF REPLACEMENT/FULL REPLACEMENT	4	4	6,800	100,000	1,000,000				
01301		2015-0719	DISTRIBUTION TANK AND RESERVOIR PAVING	4	4	0	80,000	80,000	80,000	80,000	80,000	
01301		2016-0753	BASKIN OVERFLOW/DRAIN GOOSENECK BOX	4	4	0			100,000			
01301		2017-2061	TETON TANKS SLOPE STABILIZATION	4	3	0		50,000				
01301		2015-0525	PERRY HOLLOW TANK	2	5	0	65,000					
01301	5134471	2015-0459	TANK PAINTING AND CORROSION CONTROL	3	3	100,000	200,000	200,000	200,000	200,000	200,000	
01301		2016-0935	ENSIGN DOWNS OVERFLOW	3	3	0						150,000
01301		2015-0516	MOUNT OLYMPUS TANKS & PUMP STATION BLACKTOP	2	4	0						25,000
01301		2015-0499	RAINER TANK	2	2	0						280,000
01301		2016-0917	ENSIGN DOWNS LOWER RESERVOIR MODIFICATIONS	2	2	0						200,000
01301		2015-0520	NORTH BENCH TANK ROAD	1	3	0						45,000
01301		2015-0526	VICTORY ROAD	1	3	0						22,000
01301		2016-0754	CAPITOL HILLS TANKS - TRUCK ACCESS	3	0	0						200,000
01301	513444167	2017-2121	TELFORD RESERVOIR SAFETY IMPROVEMENTS	1	2	1,234						
01301		2015-0528	NEFFS CANYON TANK	1	3	0						55,000
01301		2015-0529	EMIGRATION TANK UPGRADES	1	2	0						60,000
01301		2015-0530	TETON TANK UPGRADES	1	2	0						35,000
01301		2015-0458	MISCELLANEOUS REPAIRS	3	2	0			50,000			
01301		2017-2010	COVE TANK STABILIZATION PROJECT	2	3	0			200,000			
01301		2017-2012	TELFORD FENCE	3	0	0					30,000	
01301		2017-2013	EAST BENCH TANKS DRAIN LINE GOOSENECK	1	3	0					25,000	
01301		2017-2059	VICTORY ROAD TANK OVERFLOW DRAIN	4	4	0		50,000				
01301		2017-2064	CARRIGAN COVE TANK POWER	2	3	0				50,000		
01301		2017-2112	GRANITE OAKS/TELFORD RESERVOIR REPAIRS	3	3	0			50,000			
01301		2017-2118	GRANITE OAKS ACCESS ROAD	1	4	0			100,000			
01301		2018-1023	BASKIN RESERVOIR EFFLUENT PIPE	4	4	0		500,000				
01301		2018-1024	BASKIN ROOF REPLACEMENT	5	5	0	50,000					
01301		2018-1026	TANK AND RESERVOIR FALL PROTECTION SYSTEMS	5	0	0	100,000					
01301		2018-1031	MILITARY RESERVOIR - JOINT SEALANT REPAIR	5	4	0		20,000				
01301		2018-1032	MILITARY RESERVOIR - REPAIR INLET/OUTLET PIPE	5	4	0		50,000				
01301		2018-1033	MILITARY RESERVOIR CONDITION ASSESSMENT	5	4	0		20,000				
01301		2018-1092	FENCE 300 EAST GORDON LANE	1	4	0				5,000		
						$ 675,745	$ 845,000	$ 6,070,000	$ 880,000	$ 435,000	$ 435,000	$ 14,737,000
51-01301-	2730.08		**DISTRIBUTION MAINS & HYDRANTS**									
			CITY, COUNTY, STATE AND MISC. DRIVEN PROJECTS									
01301	513505272	2016-1233	WATER MAIN REPLACEMENT - 900 SOUTH	5	5	0	800,000					
01301	513505273	2016-0744	1300 EAST - WATER LINE	3	4	2,417,148						
01301	513505312	2015-0431	CITY/COUNTY/STATE DRIVEN PROJECTS	5	5	250,000	350,000	350,000	350,000	350,000	350,000	
01301		2016-1264	NW QUADRANT (DEVELOPMENT) PIPE UPSIZE	5	5	0						1,400,000
01301	513600099	2017-2056	ENERGY EFFICIENCY/RENEWABLE ENERGY CAPITAL IMPROVEMENTS	5	5	200,000	200,000	200,000	200,000	200,000	200,000	

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01301	513505308	2015-0398	UPPER CONDUIT METER REPLACEMENT	4	5	50,000						
01301	513600097	2017-2014	MOTORS AT WORK	4	4	16,000						
01301	513505230	2015-0245	EAST INDIANA AVENUE (850 SOUTH) - REDWOOD RD TO SURPLUS	3	5	149,072	985,000					
01301	513505332		CITY CREEK WATER MAIN VAULT REMOVAL			25,000						
01301		2018-1081	STATE IPS RESOLUTIONS	4	4	0	20,000	20,000	20,000	20,000	20,000	
01301	513505334		STATE "BETTERMENT" PROJECT, WATER LINE CROSSING 5600 WEST AT 1100 SOUTH			0	72,600					
01301			STATE 1100 SOUTH, 5600 WEST TO LEGACY VIEW (ABOUT 5700 W)			0	25,000					
			700 WEST - 1600 SOUTH TO 2100 SOUTH				100,000					
			LOCAL STREET DISTRICT 1 & 7				200,000					
			800 WEST - 600 SOUTH TO 800 SOUTH				350,000					
			500 EAST - 1700 SOUTH TO 2100 SOUTH				950,000					
			2000 EAST - PARLEY'S TO CITY LIMIT				300,000					
			1900 EAST - WILMINGTON TO PARLEYS CANYON				250,000					
			900 SOUTH - 900 WEST TO 900 EAST				5,000,000					
			300 WEST - 600 SOUTH TO 2100 SOUTH				2,500,000					
			LOCAL STREETS DISTRICT 3 & 6					200,000				
			900 EAST - HOLLYWOOD TO 2700 SOUTH					340,000				
			100 SOUTH - NORTH CAMPUS DRIVE TO 900 EAST					390,000				
			1700 EAST - 1700 SOUTH TO 2700 SOUTH					60,000				
			LOCAL STREETS DISTRICTS 2 & 5						200,000			
			200 SOUTH - 400 WEST TO 900 EAST						4,000,000			
			1100 EAST HIGHLAND , RAMONA TO WARNOCK							1,000,000		
			LOCAL STREETS DISTRICT 4 & 7							200,000		
			1100 EAST - 900 SOUTH TO RAMONA							4,000,000		
			300 NORTH - 300 WEST TO 1000 WEST							1,500,000		
			W TEMPLE - NORTH TEMPLE TO 400 SOUTH								800,000	
			LOCAL STREETS 3 & 6								200,000	
			VIRGINIA STREET - SOUTH TEMPLE TO 11TH AVE								100,000	
			1300 EAST - 2100 SOUTH TO 3000 SOUTH									
			2100 SOUTH - 700 EAST TO 1700 EAST									2,500,000
			LOCAL STREETS DISTRICT 1, 4 & 5									200,000
			GLADIOLA STREET - 900 SOUTH TO CALIFORNIA									50,000
			300 WEST - 400 SOUTH TO 900 SOUTH									2,000,000
			WAKARA WAY - FOOTHILL DRIVE TO CHIPETA WAY									150,000
						$ 3,107,220	$ 12,102,600	$ 1,560,000	$ 4,770,000	$ 7,270,000	$ 1,670,000	$ 6,300,000
			WATER MAIN MISCELLANEOUS PROJECTS									
01301	514500020	2015-0491	REGULATOR REPLACEMENT	5	5	20,000	300,000	300,000	300,000	300,000	300,000	
01301	513302118	2015-0493	NEW MAINLINE VALVES - COUNTY	5	5	138,000	138,000	138,000	138,000	138,000	138,000	
01301	513505311	2015-0489	NEW WATER LINES - CONTRIBUTIONS BY DEVELOPERS	5	5	500,000	500,000	500,000	500,000	500,000	500,000	
01301	513505310	2015-0490	FIRE HYDRANT REPLACEMENTS	5	5	400,000	400,000	400,000	400,000	400,000	400,000	
01301	513505309	2015-0492	NEW MAINLINE VALVES - CITY	5	5	262,000	262,000	262,000	262,000	262,000	262,000	
01301	513505304	2018-1002	UPPER CONUIT - LINE SYPHON	5	4	329,549	3,000,000					
01301	514500019	2016-0961	4TH AND A PRV	4	5	178,665						
01301		2016-0958	10TH AND B PRV	3	4	0		210,000				
01301		2016-0751	RECONNECTION OF 1700 SOUTH AND FOOTHILL UTILITIES	2	4	0			20,000			
01301	513600098	2017-2072	SAMPLING TAPS	3	3	50,000	10,000	10,000	10,000			
01301		2016-0923	SAM PARK INLET VAULT	3	3	0			35,000			
01301		2016-0959	10TH AND E PRV	3	3	0			210,000			
01301		2016-0960	8TH AND L PRV	3	3	0						210,000
01301		2016-0914	CONNECTIONS AT RR	4	0	0						440,000
01301	513600103		CORROSION CONTROL PROGRAM			47,653						
01301	514506		1000 EAST 500 SOUTH PRV			0	1,500,000					

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						$ 1,925,867	$ 6,110,000	$ 1,820,000	$ 1,875,000	$ 1,600,000	$ 1,600,000	$ 650,000
			WATER MAIN REPLACEMENTS									
01301	513505314		SMALL DIAMETER PIPE REPLACEMENT PROGRAM	5	5	250,000	250,000	250,000	250,000	250,000	250,000	
01301	513505203	2015-0247	600 WEST - 600 NORTH TO RAILROAD CROSSING	5	4	187,620						
01301	513505216		1000 NORTH - 1500 WEST TO REDWOOD ROAD	4	5	0	300,000					
01301	513302017	2015-0618	900 EAST AND 5600 SOUTH WATER MAIN REPLACEMENT	5	5	1,249				1,500,000		
01301	513302116	2016-0739	MILLCREEK WAY WATER MAIN REPLACEMENT	5	5	28,500	190,000					
01301	513505306	2017-2063	SCENIC DRIVE UPPER CONDUIT SLIPLINE PROJECT	5	5	0	300,000					3,000,000
01301	513505208	2015-0240	J STREET - SUNRISE AVENUE TO NORTHCREST DRIVE	5	4	492,260						
01301		2016-0921	BACKFEED FOR UTAH STATE CAPITOL	5	4	0		60,000				
01301		2016-1234	SHED AT EMIGRATION WELL	5	4	0			50,000			
01301	513505151	2015-0543	700 SOUTH - 300 WEST TO 700 WEST	5	4	0	630,000					
01301	513505156	2015-0233	200 SOUTH - 600 WEST TO JEREMY STREET	4	5	0	413,500					
01301	513505193	2015-0235	BECK STREET - 1805 NORTH TO 1180 NORTH	4	5	0						1,247,000
01301	513505207	2015-0252	3390 SOUTH - 700 EAST TO RIVIERA DRIVE	4	5	80,000	175,000					
01301	513504858	2015-0547	DULUTH AVE (1550 N) - 900 W TO DEXTER, 900 W - 1500 N TO DULUTH	4	5	1,688	175,000					
01301	513505130	2015-0549	FOOTHILL DRIVE - EMERSON AVE TO KENSINGTON AVE	4	5	0	105,000					
01301	513302047	2015-0617	MILLSTREAM DRIVE (3580 S) - MARDONNA WAY TO EASTWOOD DRIVE	4	5	0	274,000					
01301	513505133	2015-0624	1700 SOUTH - 1000 EAST TO 1100 EAST	4	5	0		160,000				
01301		2016-1230	17TH AND FOOTHILL TELEMETRY AND POWER	4	5	0			200,000			
01301		2015-0255	REDWOOD ROAD - 500 SOUTH TO 1050 SOUTH	4	5	0			918,000			
01301	513505212	2015-0253	PLEASANT VALLEY LINE	4	5	0						653,000
01301		2015-0254	CITY CREEK HIGHLINE	4	5	0						460,000
01301		2015-0554	SOUTH TEMPLE 1000 W.(GATSPY LINE)	5	3	0						415,000
01301	513505198	2015-0237	GREGSON AVENUE - 2465 EAST TO 2700 EAST	4	4	0						80,000
01301	513302089	2015-0238	2300 EAST - 6200 SOUTH TO 6400 SOUTH	4	4	0						268,000
01301	513505202	2015-0246	420 N MAIN STREET - 1" SERVICE REPLACEMENT - MAIN ST TO WALL ST	4	4	0						64,000
01301	513505125	2015-0260	WEST TEMPLE - 500 SOUTH TO 800 SOUTH (EAST SIDE)	4	4	0						469,000
01301	513505127	2015-0262	1000 WEST/1400 SOUTH WATER MAIN REPLACEMENT	4	4	0						560,000
01301		2017-2022	2880 SOUTH WATER MAIN REPLACEMENT	4	4	0						260,000
01301	513505197	2015-0236	800 SOUTH - 1200 EAST TO 1220 EAST	3	5	0						134,000
01301	513302039	2015-0613	OAK CREEK DRIVE - 8200 SOUTH TO END OF LINE	3	5	0						300,000
01301	513302045	2015-0616	MARDONNA WAY (3545 S) - SUNILAND DRIVE TO MILLSTREAM DRIVE	3	5	0						153,000
01301	513505128	2015-0620	WILTON WAY WATER MAIN REPLACEMENT	3	5	0						374,000
01301	513505129	2015-0621	1700 SOUTH - FOOTHILL TO WASATCH WATER MAIN REPLACEMENTS	3	5	0						257,000
01301	513505132	2015-0622	MILTON AVENUE (1595 SOUTH) - 1100 EAST TO 1200 EAST	3	5	0						179,000
01301		2017-2066	2700 E DEAD-END CONNECTION	3	5	0						20,000
01301		2016-0738	RELOCATE 12" CIP MAIN FROM UNDER HOUSE (EAST BENCH SUCTION LINE)	5	2	0						255,000
01301	513302090	2015-0239	COBBLECREST RD - 6380 S TO 2300 E; HAUN AVE - 2300 E TO COBBLECREST	4	3	0						411,000
01301		2015-0232	NORTH TEMPLE - 1800 WEST TO REDWOOD ROAD	4	3	0						156,200
01301	513505155	2015-0241	WESTMINSTER AVENUE - LAURELHURST (2550 EAST) TO FOOTHILL BOULEVARD (2600 EAST)	4	3	0						90,000
01301	513302038	2015-0258	BISCAYNE DR (2975 E) - BENGAL BLVD TO OAKVIEW CIR	4	3	0						158,000
01301	513505122	2015-0550	DUPONT AVE (1335 N) - AMERICAN BEAUTY DR TO 990 W	4	3	0						115,000
01301		2016-1228	REPLACE PRV'S - R11 AND R12	4	3	0						400,000
01301	513505205	2015-0249	SCOTT AVENUE - 700 EAST TO SCOTT PARK LANE	3	4	0						105,000
01301		2015-0400	R37. MAYWOOD REGULATOR	3	4	0						150,000
01301	513505134	2015-0625	BRYAN AVENUE (1565 SOUTH) - 900 EAST TO 1000 EAST	3	4	0						172,000
01301		2016-0889	CR1 PRV	3	4	0						225,000
01301		2016-0890	CR2 PRV	3	4	0						225,000
01301		2016-0891	HYDRANT 3300 SOUTH	3	4	0						40,000
01301		2016-0901	PRV E3-R49 REPLACEMENT	3	4	0						220,000
01301		2016-0910	HIGHLAND DRIVE REGULATORS	3	4	0						1,300,000

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01301		2016-0912	R73 REPLACEMENT	3	4	0						200,000
01301		2016-0913	CUP REGULATORS	3	4	0						300,000
01301		2016-0918	2300 EAST - CLAYBOURNE TO 3300 SOUTH	3	4	0						200,000
01301		2016-0934	PRV AT 17TH	3	4	0						210,000
01301		2016-1169	J STREET PIPELINE AND PRV REPLACEMENT	3	4	0						300,000
01301		2016-1273	NEW WATER MAIN - 1000 EAST	3	4	0						300,000
01301		2017-2062	ROXBURY PRV C46-R66	3	4	0						150,000
01301		2017-2065	CAMILLE ST. DEAD-END CONNECTION	3	4	0						20,000
01301		2016-1283	SUICIDE ROCK RUNAROUND	2	5	0						25,000
01301	513302117	2017-2069	CAP STUB AT 6200 SOUTH HOLLADAY BOULEVARD	3	3	2,250						
01301	513505124	2015-0619	BUCCANEER DRIVE WATER MAIN REPLACEMENT	3	3	0						151,000
01301		2016-0748	WATER VALVE REPLACEMENT PROJECT #3	2	4	0						100,000
01301	513505199	2015-0242	700 EAST - DRIGGS AVE (2370 S) TO WARNOCK AVE (2470 S)	1	5	0						257,000
01301		2015-0256	900 EAST HILLVIEW (4060 SOUTH) - REPLACE DIP MAIN UNDER SEWER	1	5	0						36,000
01301		2016-0756	300 WEST - 700 S TO 800 S	1	5	0						175,000
01301		2016-0892	KEARNS LINE REPLACEMENT	3	3	0						8,000,000
01301		2016-0900	R48 VALVE	3	3	0						20,000
01301		2016-0906	6-INCH ON 9TH	3	3	0						450,000
01301		2016-0915	SMITHS CONNECTION	3	3	0						70,000
01301		2016-0916	COUNTRY CLUB PRV	3	3	0						250,000
01301		2016-0933	MAYWOOD 6-INCH	3	3	0						220,000
01301		2016-0936	16-INCH VALVE VAULT	3	3	0						65,000
01301		2016-1222	PRV REPLACEMENT - A8-14	3	3	0						200,000
01301		2016-1231	NEW PRV - R73	3	3	0						200,000
01301		2016-1232	NEW PRV - R74	3	3	0						200,000
01301		2016-1235	POWER AT EMIGRATION TUNNEL	3	3	0						100,000
01301		2015-0399	RESEARCH PARK UPGRADE	5	0	0						410,000
01301		2016-0919	INSERTA VALVES	5	0	0						50,000
01301		2017-1299	EDWARD DRIVE REGULATED IMPROVEMENTS	5	0	0						500,000
01301		2017-2068	INDIAN ROCK PRESSURE ZONE REDUNDANT FEED	5	0	0						250,000
01301		2017-2070	HIGHLAND DR WATER MAIN - 6200 S TO DIAMOND HILLS LN	3	2	0						250,000
01301	513302046	2015-0615	SUNILAND DRIVE (3550 E) - MILLSTREAM LANE TO END OF SUNILAND CIRCLE	3	2	0						149,000
01301		2015-0426	FORT UNION AND HIGHLAND AVE INTERSECTION	2	3	0						302,500
01301		2017-2011	900 EAST FROM VAN WINKLE TO 5600 SOUTH	2	3	0						100,000
01301	513505204	2015-0248	500 SOUTH - 2130 WEST TO ORANGE STREET	4	0	0						315,000
01301	513302021	2015-0250	6200 SOUTH - 2900 EAST TO 3000 EAST	4	0	0						350,000
01301	513302058	2015-0544	SHORT HILLS DR (3375 E) - 8220 SOUTH TO 8315 SOUTH	4	0	0						55,000
01301		2015-0397	SUICIDE ROCK VAULT	2	2	0						100,000
01301		2016-0925	2700 E CONNECTION	2	2	0						60,000
01301		2015-0480	1700 EAST FROM FT UNION BLVD (6935 S) TO 7080 SOUTH	1	3	0						360,000
01301	513302059	2015-0548	3900 SOUTH - 900 EAST TO 940 EAST	3	0	0						130,000
01301		2015-0586	PARLEY'S CANYON BLVD 1700 EAST TO 1800 EAST	3	0	0						181,000
01301	513505166	2015-0626	400 EAST - 1497 SOUTH TO 1530 SOUTH	3	0	0						37,000
01301	513505167	2015-0627	1400 EAST - GILMER AVENUE TO YALE AVENUE	3	0	0						32,000
01301		2016-0957	MORRIS PUMP STATION	3	0	0						600,000
01301		2016-1168	KEARNS VALVE	3	0	0						30,000
01301		2015-0413	700 NORTH 8" AC	2	1	0						115,000
01301		2015-0641	LITTLE COTTONWOOD CREEK CEMENT CAP 4"	1	2	0						35,000
01301		2015-0407	2200 WEST WATER MAIN EXTENSION	1	0	0						255,000
01301	514000040		ASPHALT PATCHING 2018			30,000						
01301		2018-1096	CHEYENNE STREET WATER LINE REPLACEMENT	3	4	0			50,000			
01301		2016-0856	7000 SOUTH SAND TRAP AND SCREEN REMOVAL	5	5	0		20,000				
01301		2018-1041	UPPER BOUNDARY SPRINGS EFFLUENT LINE REPLACEMENT FROM SPRING BOX TO TANK	4	5	0		500,000				
01301		2017-2018	DULUTH AVE AND 900 WEST WATER MAIN REPLACEMENT	3	5	0	325,000		400,000			

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01301		2017-2110	DEVELOPER DRIVEN PROJECTS	4	4	0	100,000					
01301		2018-1079	2100 SOUTH, 700 EAST TO 1300 EAST, WATER LINE REPLACEMENT	3	4	0		1,800,000				
01301		2018-1089	EAST BENCH SUCTION LINE RELOCATION	4	2	0			96,400			
						$ 1,073,567	$ 3,237,500	$ 2,790,000	$ 1,964,400	$ 1,750,000	$ 250,000	$ 29,780,700
			MASTER PLAN PROJECTS									
01301	513416337	2015-0629	MP3.16 - NORTH BENCH PUMP STATION	5	5	15,065			1,500,000			
01301	513505088	2015-0217	CITY CREEK TREATMENT LINE TO MORRIS RESERVOIR	5	4	0	80,000		800,000			
01301	513302020	2015-0230	3RD EAST PHASE II - MARCUS TO ARTESIAN BASIN	4	4	266,503	4,000,000					
01301	51360062	2015-0632	MP2.3 - WASTEWATER REUSE	4	3	0						23,000,000
01301	513505116	2015-0633	MILLCREEK TREATMENT PLANT LINE - TANK TO WASATCH BLVD (24")	4	3	0						750,000
01301	513416327	2015-0218	MP 3.5B - 16" PIPELINE ON NEWPORT WAY/NANTUCKET DRIVE	4	2	0						394,000
01301	513302063	2015-0224	MP 3.5A - 12" PIPELINE ON HIGHLAND DR (6200 S HIGH ZONE)	3	3	0						317,000
01301		2015-0229	MP 3.17 - 8" LOOP AT 2200 WEST/2200 NORTH	5	0	0						948,000
01301	513505159	2015-0222	MP3.14 - AUXILIARY POWER - GOLDEN HILLS	5	0	0						45,000
01301	513505168		CAPITOL HILL TO ENSIGN DOWNS PIPELINE	4	0	0						5,000,000
01301	513302062	2015-0219	MP3.9 - NEW PUMP STATION - TETON TO MT. OLYMPUS/4500 SOUTH HIGH - IF	4	0	0						695,000
01301	513302061	2015-0220	MP3.6B - 12" PIPELINE ON BRIGHTON WAY	4	0	0						200,000
01301	513505117	2015-0221	MP3.5C - 16" PIPELINE ON BENGAL BOULEVARD	4	0	0						1,134,000
01301	513505098	2015-0225	MP3.1A - EAST-WEST CONVEYANCE LINE - PARK RESERVOIR TO SUGARHOUSE PARK	4	0	299,181	10,000,000	10,000,000				
01301		2015-0231	MP 3.8C - VICTORY ROAD - ENSIGN DOWNS PHASE II - IF	4	0	0						2,250,000
01301	5134493	2015-0634	MP3.1B - EAST WEST CONVEYANCE LINE - SUGARHOUSE PARK TO 900 WEST	4	0	0						7,000,000
01301	5134464	2015-0227	MP3.7 - ADD THROTTLING CONTROL VALVE INTO WILSON RESERVOIR	3	0	0						150,000
01301		2015-0538	MP 3.12A - 7800 SOUTH PRESSURE ZONE - 4.3 MG RESERVOIR	2	0	0						3,000,000
01301	51360060	2015-0636	MP2.1 - DEVELOP ADDITIONAL GROUND WATER SOURCES	2	0	0						18,000,000
01301	513505169	2015-0630	MP2.2 - ADDITIONAL SURFACE WATER DEVELOPMENT	2	0	0						12,000,000
01301	51360061	2015-0635	MP3.1C - EAST WEST CONVEYANCE LINE - 900 WEST TO 3400 WEST (PHASE 3)	1	0	0						12,000,000
01301		2015-0631	MILLCREEK WATER TREATMENT FACILITY	1	0	0						80,000,000
01301			UPDATE WATER MASTER PLAN			0			400,000			
						$ 580,749	$ 14,080,000	$ 10,000,000	$ 2,700,000	$ -	$ -	$ 166,883,000
			TOTAL DISTRIBUTION MAINS & HYDRANTS			$ 6,687,404	$ 35,530,100	$ 16,170,000	$ 11,309,400	$ 10,620,000	$ 3,520,000	$ 203,613,700
	2730.09		**WATER SERVICE CONNECTIONS**									
03301	513900116	2015-0534	2700 EAST - RELOCATE SERVICE CONNECTIONS	3	3	7,227						
01701	513900126	2015-0494	SERVICE LINE REPAIR/REPLACEMENTS	5	5	1,800,000	1,800,000	1,800,000	1,800,000	1,800,000	1,800,000	
03301	513900125	2015-0495	NEW SERVICE CONNECTIONS	5	5	400,000	400,000	400,000	400,000	400,000	400,000	
02201	513900124	2015-0496	LARGE METER REPLACEMENTS	5	5	400,000	400,000	400,000	400,000	400,000	400,000	
02601	513900123	2015-0498	METER REPLACEMENT PROGRAM	5	5	200,000	200,000	200,000	200,000	200,000	200,000	
	513900120		AMI TOWERS - CITY	4	0	97,219						
	513900121	2017-2122	AMI TOWERS - COUNTY	4	0	123,711						
	513900122	2017-2126	AMI METER REPLACEMENT PROGRAM	1	0	3,100,000	3,100,000	3,100,000	3,100,000	3,100,000	3,100,000	
						$ 6,128,156	$ 5,900,000	$ 5,900,000	$ 5,900,000	$ 5,900,000	$ 5,900,000	$ -
	2730.20		**LANDSCAPING**									
			WATERSHED									
00601	5122672	2017-1295	RECREATION AREA PICNIC TABLE REPLACEMENT	5	5	3,750						
00601	5122673	2015-0670	ACCESSIBILITY UPGRADES TO WATERSHED RECREATION FACILITIES	5	0	38,069		200,000		200,000		
	512627466	2017-2032	SILVER LAKE RESTROOM DEMOLISH AND REPLACE	5	5	290,784						

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00601	512627463	2017-1296	BIG COTTONWOOD CANYON PARK & RIDE RESTROOM REBUILD	5	5	0		500,000				
	514700004	2017-2117	CITY CREEK ROADWAY ASPHALT	5	5	0	100,000	100,000				
03201	51360014	2015-0519	WEST TEMPLE CAMPUS - CONSERVATION IMPROVEMENTS	2	4	11,250						
		2018-1028	CITY CREEK CANYON ROAD RECONSTRUCTION	5	5	0			500,000	1,000,000	1,000,000	1,000,000
		2018-1110	SITE 30 PAVILION STRUCTURAL REVIEW	2	4	0	20,000					
			CITY CREEK WATER SYSTEM TO SITES 23 THROUGH 30									500,000
						$ 343,852	$ 120,000	$ 800,000	$ 500,000	$ 1,200,000	$ 1,000,000	$ 1,500,000
			TOTAL CAPITAL IMPROVEMENTS			$ 24,629,211	$ 59,255,100	$ 53,501,500	$ 38,542,400	$ 42,350,000	$ 29,914,000	$ 596,995,700

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	2710.10			**LAND**										
5103301	2710.10		2015-0427	WATERSHED PROPERTY		5	0		1,500,000	1,500,000	1,500,000	1,500,000	1,500,000	1,500,000
5103301	2710.10		2015-0481	1811 WEST 500 SOUTH		5	5							
5103301	2710.10			2668 EAST COMANCHE DRIVE										
5103301	2710.10			983 N PINECREST CANYON ROAD EMIGRATION CANYON										
5103301	2710.10		2015-0172	MP 3.8C - VICTORY ROAD - ENSIGN DOWNS PHASE II - PF		4	0	590,737						
								$ 590,737	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000
	2710.30			**WATER RIGHTS & SUPPLY**										
5103301	2710.30			2,552 SHARES HILL DITCH @ $475				1,212,200						
5103301	2710.30			Various					30,000	30,000	30,000	30,000	30,000	
5103301	2710.30		2015-0488	56 SHARES UPPER CANAL IRRIIGATION @ $400		2	2	22,400						
								$ 1,234,600	$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ -
	2750.10		Replace No.	**AUTOMOBILES & TRUCKS**										
5100101	2750.10		New	Ford F550 1 Ton C&C w/Bed Cost Center				49,000						
5100601	2750.10		31136	CHEVROLET 3/4 TON PICK-UP TRUCK				28,961						
5100601	2750.10			2019 F350 CHASSIS XL 4X4 SD				31,640						
5100601	2750.10			SNOW PLOW				4,908						
5100601	2750.10			RUGBY DUMP BODY				7,858						
5100701	2750.10			UTV - Brutis				29,007						
5100701	2750.10			FORD F-350 CREW CAB 4X4 SHORT BED				31,299						
5100701	2750.10			SNOW PLOW				4,520						
5100701	2750.10			SALT SPREADER				4,804						
5100801	2750.10		31117	GMC 3/4 Ton Cab-n-Chassis Flat Bed to Plow				44,195						
5101301	2750.10		31068	ESCAPE SUV 4X4				22,507						
5101301	2750.10			INSPECTION VEHICLES (2)				60,575						
5101301	2750.10			2018 FORD FOCUS ELECTRIC 4DR				28,287						
5101401	2750.10		31016	Chevrolet 3/4 Ton Pick-up Truck w/ Lift Gate				37,831						
5101401	2750.10		31005/31006/31009	3/4 P U/ replace w/1/4 Ton Pick-up 2wd (3)				66,483						
5101401	2750.10		31095/31096	3/4 Ton Cab-n-Chassis w/Util. Bed 4wd ext Cab (2)				68,780						
5101601	2750.10		31112	REPLACEMENT FOR SURVEY VEHICLE 31112 Sell				57,922						
5101601	2750.10		31130	GMC 1/4 TON PICK-UP TRUCK				24,230						
5101701	2750.10		31115/31116/NEW	INTERNATIONAL V&H TRUCKS 7400 4X2 (3)				439,158						
5101701	2750.10		New	Freightliner Dump Truck				138,378						
5101701	2750.10		New	Escape SUV				22,507						
5101801	2750.10		31134	GMC Canyon				28,961						
5102101	2750.10		31082	CHEVROLET 1/4 TON PICK-UP TRUCK				22,161						
5102601	2750.10		31128	GMC 3/4 Ton Pick-up Truck				29,637						
5102601	2750.10		New	GMC 1 Ton Pick-up Truck				36,515						
5102801	2750.10		36960	GMC 1/4 TON PICK-UP TRUCK				28,961						

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5101301	2750.10			CHEV OR SIMILAR MID-SIZED 4X4 PICK UP W/	Jason				30,000					
5101301	2750.10			CHEV OR SIMILAR MID-SIZED 4X4 PICK UP W/	Jason				30,000					
5102601	2750.10		31128	4X4 1/2 TON VXU W/CAMPER SHELL					27,000					
5102601	2750.10		31146	1/4 TON					25,000					
5102601	2750.10		36950	1 TON NON-DUMPING FLAT BED					37,000					
5102601	2750.10		31204	CHEVY COLORADO 4WD					29,500					
5100901	2750.10		31281	FORD F-150 4WD	Marian				35,000					
5101801	2750.10		31134	COLORADO 4WD	Marian				30,000					
5101801	2750.10		31177	CHEVY COLORADO 4WD	Marian				30,000					
5100701	2750.10		NEW	1/4 TON 4WD, EXTENDED CAB, POWER WIND	Marian				30,000					
5100601	2750.10		NEW	1/4 TON 4WD, EXTENDED CAB, POWER WIND	Marian				30,000					
5100601	2750.10		NEW	1/4 ton, 4-wheel Drive, extended cab, power wind	Marian				40,000					
5100101	2750.10		31087	Replace Ford F250, State contract	Randy				41,500					
5100101	2750.10		3703	John Deere 5100M W/Mower	Randy				79,265					
5102301	2750.10			VARIOUS						1,000,000	1,000,000	1,000,000	1,000,000	
								1,349,084	494,265	1,000,000	1,000,000	1,000,000	1,000,000	-
	2750.30			**FIELD MAINT EQUIPMENT - MOTIVE**										
5100101	2750.30			Link Belt 160 x 4 Excavator				180,000						
5100101	2750.30			S550 Slide in Ass'y (Masport H XL3 Direct Drive) Alum				11,161						
5101701	2750.30			Case Backhoe				92,616						
5101701	2750.30			BACKHOE EXCHANGE PROGRAM				81,000						
5101701	2750.30			Backhoe Trailer				28,375						
5102101	2750.30			Hyster Fork Lift				43,981						
5102201	2750.30			Interstate 50tdc Trailer				28,375						
5102301	2750.30			VARIOUS				95,500		50,000	50,000	50000	50000	
5102601	2750.30			HANDHELD READING UNITS (2)	Audree				17,232					
5101601	2750.30		31148	CHEVY/GMC 4X4 EXT CAP	Nick				30,000					
5101601	2750.30		31149	CHEVY/GMC 4X4 EXT CAP	Nick				30,000					
5101601	2750.30		31150	CHEVY/GMC 4X4 EXT CAP	Nick				30,000					
5101401	2750.30		80564	SKAGG SVRII-36A-19FX	Jason/Randy				9,550					
5100101	2750.30		NEW	CAT/WHEELER BUCKET - DC 60" DITCH	Jason/Randy				5,400					
5101601	2750.30			KUBOTA BX235 Mini-Tractor	Marian				25,000					
5101601	2750.30			Winter Tractor	Marian				28,000					
								561,008	175,182	50,000	50,000	50,000	50,000	-
	2760.10			**PUMP PLANT EQUIPMENT**										
5100801	2760.10			CLEAR WATER AND AREA DRAIN PUMPS				40,000						
5100801	2760.10			REPLACE EXISTING LMI CHEMICAL FEED PUMPS				9,537						

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5100801	2760.10			REPLACE VALVING MAINFOLD IN PUMP HOUSE				100,000						
5100901	2760.10			EQUALIZATION PUMP				19,455						
5100901	2760.10			WASTEWATER RETURN PUMP				13,492						
5101301	2760.10			VARIOUS				50,000	50,000	50,000	50,000	50,000	50,000	
								232,484	50,000	50,000	50,000	50,000	50,000	-
	2760.20			**TREATMENT PLANT EQUIPMENT**										
5100701	2760.20			FLOC BUSHING		4	4	30,000						
5100701	2760.20	5122631		SECURITY FENCE FOR SLUDGE BEDS/BACKWASH TANK		3	3	75,000						
5100701	2760.20	5122632		SECURITY FENCING FOR BACK OF PLANT		3	3	40,000						
5100701	2760.20			REPLACEMENT PARTICLE COUNTERS				24,000						
5100701	2760.20			TURBIDITY METERS				35,000						
5100701	2760.20			ON-DEMAND HOT WATER HEATERS										
5100801	2760.20			DR 6000-PHOTANALYZER (UV BULB)				8,000						
5100801	2760.20			CHLORINE ANALYZER				8,000						
5100801	2760.20			HEADLOSS METER				13,300						
5100801	2760.20	18		BACK-UP WATER SUPPLY FROM CLEARWELL TO HIGH PRESSURE TANK										
5100801	2760.20	5124508		PARLEY'S TP - REPLACE ALL POST STORAGE TANK HYP(		1	1							
5100801	2760.20			DR 6000-PHOTOANALYZER (UV BULB)				8,000						
5100801	2760.20			CHLORINE ANALYZER				8,000						
5100801	2760.20			HEADLOSS METER				13,300						
5100801	2760.20			FLYGT 4" SUBMERSIBLE PUMP MODEL CP3102.090				13,910						
5100901	2760.20			HYDROMATIC SUBMERSIBLE SOLIDS HANDLING PUMP				13,910						
5100901	2760.20			FLOC BUSHING		4	4	30,000						
5100901	2760.20			CAMERA UPGRADE BIG COTTONWOOD										
5100901	2760.20			ONLINE TURBIDITY METER				70,000						
5101301	2760.20			VARIOUS				100,000		100,000	100,000	100000	100000	
5100801	2760.20			SURFACE WASH PUMP	Marian				60,000					
								490,420	60,000	100,000	100,000	100,000	100,000	-
	2760.30			**TELEMETRY EQUIPMENT**										
5101501	2760.30			MISCELLANEOUS WATER TELEMETRY 2018/2019				50,000	50,000	50,000	50,000	50,000	50,000	
5101501	2760.30			Telemetry Equipment - Water Ongoing				50,000						
5101501	2760.30			CCTV Recorder - Dispatch				10,000						
5101501	2760.30		2017-1308	INSTALLATION OF NEW SNOW GAUGING STATIONS		4	0	60,000						
5100201	2760.30			TELEMETRY FOR TWIN LAKES										
								170,000	50,000	50,000	50,000	50,000	50,000	-
	2760.50			**OFFICE FURNITURE & EQUIPMENT**										
5103201	2760.50			SOFTWARE UPGRADE BILLING SYSTEM				30,000	30,000	30,000	30,000	30000	30000	
5101301	2760.50			Full Function Printer replacement "Engineering"				5,765						
5103301	2760.50			Full Function Printer replacement "Contracts"				5,765						
	2760.90			**OTHER NON-MOTIVE EQUIPMENT**				41,530	30,000	30,000	30,000	30,000	30,000	-

WATER UTILITY CAPITAL PURCHASES BUDGET
Five Year Projected Budget FY2020-2024

COST CENTER	OBJECT CODE	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	Comments	CRITICALITY RATING	CONDITION RATING	PAST YEAR BUDGET 2018-19	BUDGET YEAR 2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
5103201	2760.90			VARIOUS				50,000	50,000	50,000	50,000	50,000	50,000	
5101701	2760.90			EMERGENCY PIPING				50,000	50,000	50,000	50,000	50,000	50,000	
5102601	2760.90			HANDHELD METER READING DEVICES				20,000	20,000	20,000	20,000	20,000	20,000	
5100601	2760.90			WOOD CHIPPER				79,010						
5100601	2760.90			NEW 2018 MCLAUGHLIN VSK 25-100G VACUUM				18,965						
5101201	2760.90			TRAILER FOR SPILL RESPONSE AT DIVERSION				6,000						
5101201	2760.90			BOAT				5,000						
								228,975	120,000	120,000	120,000	120,000	120,000	-
				TOTAL CAPITAL OUTLAY				$ 4,898,838	$ 2,509,447	$2,930,000	$2,930,000	$2,930,000	$2,930,000	$1,500,000

Sewer Utility- Budget Summary and Cash Flow

SEWER UTILITY
ENTERPRISE FUND
BUDGET SUMMARY
FY 2020-22

SOURCES	ACTUAL 2017-18	AMENDED BUDGET 2018-19	PROJECTED ACTUAL 2018-19	Rate Increase 18% PROPOSED BUDGET 2019-20	Rate Increase 18% FORECAST BUDGET 2020-21	Rate Increase 18% FORECAST BUDGET 2021-22
REVENUES						
METERED SALES	$ 33,620,751	$ 37,677,666	$ 37,677,666	**$ 44,460,000**	$ 52,838,000	$ 62,791,000
INTEREST INCOME	1,579,221	1,052,000	$ 1,052,000	**604,000**	23,000	29,000
OTHER REVENUES	659,888	235,000	$ 235,000	**235,000**	235,000	235,000
TOTAL REVENUES	$ 35,859,860	$ 38,964,666	$ 38,964,666	**$ 45,299,000**	$ 53,096,000	$ 63,055,000
OTHER SOURCES						
IMPACT FEES	971,344	700,000	$ 700,000	**700,000**	724,500	749,858
GRANTS & OTHER RELATED REVENUES	978,525	2,020,000	$ 2,020,000	**2,020,000**	2,020,000	720,000
OTHER SOURCES	2,845	20,000	$ 20,000	**20,000**	20,000	20,000
STATE LOAN (NWQ)	-	-	$ -	**-**	-	-
NON BOND FINANCING	8,500,000	4,000,000	$ -	**-**	67,429,000	85,926,000
BOND PROCEEDS	-	-	$ -	**55,307,000**	39,218,000	97,542,000
T O T A L OTHER SOURCES	$ 10,452,714	$ 6,740,000	$ 2,740,000	**$ 58,047,000**	$ 109,411,500	$ 184,957,858
T O T A L SOURCES	$ 46,312,574	$ 45,704,666	$ 41,704,666	**$ 103,346,000**	$ 162,507,500	$ 248,012,858
EXPENSES & OTHER USES						
EXPENDITURES						
PERSONNEL SERVICES	$ 8,486,161	$ 10,375,345	$ 10,375,345	**$ 11,164,232**	$ 11,610,802	$ 12,075,232
OPERATING & MAINTENANCE	1,406,164	1,934,720	1,934,720	**2,109,430**	2,151,219	2,194,242
TRAVEL & TRAINING	48,179	86,900	86,900	**118,425**	120,794	123,209
UTILITIES	852,935	980,070	980,070	**994,970**	1,014,869	1,035,166
TECHNICAL SERVICES	1,831,306	3,291,348	3,291,348	**3,151,533**	3,327,843	3,394,400
DATA PROCESSING	381,234	280,000	280,000	**395,000**	402,900	410,958
FLEET MAINTENANCE	568,447	543,000	543,000	**543,000**	553,860	564,937
ADMINISTRATIVE SERVICE FEE	306,260	275,000	275,000	**311,000**	317,220	323,564
PAYMENT IN LIEU OF TAXES	306,525	368,250	368,250	**661,263**	674,488	687,978
BILLING COST	813,896	813,896	813,896	**827,634**	844,187	861,071
RISK MANAGEMENT	303,564	308,500	308,500	**260,324**	265,530	270,841
TRANSFERS TO GENERAL FUND	-	20,000	20,000	**-**	-	-
OTHER CHARGES AND SERVICES	50,100	148,588	148,588	**487,353**	496,676	506,611
TOTAL EXPENDITURES	$ 15,354,771	$ 19,425,617	$ 19,425,617	**$ 21,024,164**	$ 21,780,388	$ 22,448,209
OTHER USES						
CAPITAL OUTLAY	847,714	5,946,500	1,302,569	**8,694,000**	823,000	823,000
CAPITAL IMPROVEMENT BUDGET	33,243,806	116,640,041	60,892,051	**98,370,500**	125,728,000	210,160,000
COST OF DEBT ISSUANCE	7,200	15,000	-	**307,000**	218,000	542,000
DEBT SERVICES	5,554,277	6,058,000	6,050,603	**13,149,000**	13,399,000	13,776,000
T O T A L OTHER USES	$ 39,652,997	$ 128,659,541	$ 68,245,223	**$ 120,520,500**	$ 140,168,000	$ 225,301,000
T O T A L USES	$ 55,007,768	$ 148,085,158	$ 87,670,840	**$ 141,544,664**	$ 161,948,388	$ 247,749,209
EXCESS REVENUE AND OTHER SOURCES OVER (UNDER) USES	$ (8,695,194)	$ (102,380,492)	$ (45,966,174)	**$ (38,198,664)**	$ 559,112	$ 263,649
OPERATING CASH BALANCES						
BEGINNING JULY 1	$ 94,916,245	$ 86,221,051	$ 86,221,051	**$ 40,254,877**	$ 2,056,213	$ 2,615,325
ENDING JUNE 30	$ 86,221,051	$ (16,159,441)	$ 40,254,877	**$ 2,056,213**	$ 2,615,325	$ 2,878,974
Cash Reserve Ratio	562%	-83%	207%	**10%**	12%	13%

Cash reserve goal above 10%

SEWER UTILITY
Cash Flow
FY20 Budget
and FY2020-2024 Forecast

+18%,18%,18%,15%,10% rates
$259M in WIFIA Funds
$283M in Bonds,$55M,$39M,$97M,$65M $27M
100% CIP FY 20-24
New Debt Pmts $44.9M FY 20-24

	ACTUAL YEAR 2017-2018	PROJECTED YEAR 2018-2019	BUDGET YEAR 2019-2020	BUDGET YEAR 2020-2021	BUDGET YEAR 2021-2022	BUDGET YEAR 2022-2023	BUDGET YEAR 2023-24
SEWER SALES	$33,620,751	$37,677,666	$44,460,000	$52,838,000	$62,791,000	$72,718,000	$80,548,000
OTHER INCOME	662,733	255,000	255,000	255,000	255,000	255,000	255,000
INTEREST INCOME	1,579,221	1,052,000	604,000	23,000	29,000	31,000	30,000
OPERATING INCOME	35,862,705	38,984,666	45,319,000	53,116,000	63,075,000	73,004,000	80,833,000
NEW PLANT O&M COSTS			0	0		*(250,000)*	*(252,500)*
OPERATING EXPENSES	(15,354,771)	(19,425,617)	(21,024,164)	(21,780,388)	(22,448,209)	(23,138,679)	(23,852,612)
NET INCOME EXCLUDING DEP.	20,507,934	19,559,049	24,294,836	31,335,612	40,626,791	49,615,321	56,727,888
IMPACT FEES	971,344	700,000	700,000	724,500	749,858	776,103	803,267
STATE LOAN (NWQ)	8,500,000						
SHORT TERM FINANCING PROCEEDS							
WIFIA LOAN				67,429,000	85,926,000	65,057,000	31,865,000
NET BOND PROCEEDS	-		55,000,000	39,000,000	97,000,000	65,000,000	27,000,000
ISSUE COSTS (PROCEEDS)			307,000	218,000	542,000	363,000	151,000
ISSUE COSTS (EXP)	(7,200)		(307,000)	(218,000)	(542,000)	(363,000)	(151,000)
OTHER CONTRIBUTIONS	978,525	2,020,000	2,020,000	2,020,000	720,000	520,000	520,000
CAPITAL OUTLAY	(847,714)	(1,302,569)	(8,694,000)	(823,000)	(823,000)	(823,000)	(823,000)
STATE LOAN DEBT REPAYMENT			(6,375,000)	(2,125,000)			
NEW DEBT SERVICE			(719,000)	(2,700,000)	(5,216,000)	(9,091,000)	(12,731,000)
DEBT SERVICE	(5,554,277)	(6,050,603)	(6,055,000)	(8,574,000)	(8,560,000)	(8,561,000)	(8,935,850)
OTHER INCOME & EXPENSE	4,040,678	(4,633,172)	35,877,000	94,951,500	169,796,858	112,878,103	37,698,417
GENERATED FOR CAPITAL	24,548,612	14,925,877	60,171,836	126,287,112	210,423,649	162,493,424	94,426,305
CAPITAL IMPROVEMENTS	(33,243,806)	(60,892,051)	(98,370,500)	(125,728,000)	(210,160,000)	(162,630,000)	(94,660,000)
CASH INCREASE/(DECREASE)	(8,695,194)	(45,966,174)	(38,198,664)	559,112	263,649	(136,576)	(233,695)
		0					
BEGINING CASH BALANCE	94,916,245	86,221,051	40,254,877	2,056,213	2,615,325	2,878,974	2,742,398
CASH INCREASE/(DECREASE)	(8,695,194)	(45,966,174)	(38,198,664)	559,112	263,649	(136,576)	(233,695)
ENDING BALANCES	86,221,051.00	40,254,877.00	2,056,213	$2,615,325	$2,878,974	$2,742,398	$2,508,703
RESTRICTED/RESERVED	(10,789,378)						
AVAILABLE ENDING BALANCE	$75,431,673	$40,254,877	2,056,213	$2,615,325	$2,878,974	$2,742,398	$2,508,703
RATE CHANGE	30%	15%	18%	18%	18%	15%	10%
Cash Reserve Ratio	**562%**	**207%**	**10%**	**12%**	**13%**	**12%**	**10%**
Debt Service Coverage	**3.69**	**3.23**	**3.59**	**2.78**	**2.95**	**2.81**	**2.62**
DEBT SERVICE % OF GROSS OPERATING REV	**15%**	**16%**	**15%**	**21%**	**22%**	**24%**	**27%**
MONTHLY RESIDENTIAL UTILITY BILL AT 4 CC	**10.60**	**12.16**	**14.68**	**17.32**	**20.44**	**23.51**	**25.86**
MONTHLY RESIDENTIAL UTILITY BILL AT 8 CC	**21.20**	**24.32**	**29.36**	**34.64**	**40.88**	**47.01**	**51.71**

SEWER UTILITY CIP BUDGET
Five Year Projected Budget FY2020-2024

COST CENTER	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	CRITICALITY RATING	CONDITION RATING	PAST YEAR SPENT 2018-19 (Calc'd from P6)	BUDGET YEAR 2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
	2720.10		**MAINTENANCE & REPAIR SHOPS - 2720.10**									
		2016-0956	LIFT STATION STORAGE FACILITY	4	0	0			350,000			
						0	0	0	350,000	0	0	0
	2720.05		**LIFT STATIONS - 2720.05**									
			LIFT STATION ASSET MANAGEMENT PROGRAM									
10101	524907096		ANNUAL SYSTEM WIDE LIFT STATION SCOPING & ASSET MANAGEMENT PRIORITIZATION	5	5	200,000	200,000	200,000	80,000	80,000	80,000	320,000
			LIFT STATION RENEWAL/REPLACEMENT PROGRAM									
	52490788		LIFT STATION CONDITION ASSESSMENT (TASK ORDER 2.18)			10,938						
10101	524907095	2015-0414	ANNUAL PUMP REPLACEMENT (VARIOUS)	5	5	25,000	25,000	25,000	50,000	50,000	50,000	200,000
	52490758	2015-0266	4000 WEST LIFT STATION UPGRADE/REPLACEMENT (SS12)	5	5	911,983						
10101	52490780	2015-0263	1700 NORTH LIFT STATION REHABILITATION (SS03)	4	5	299,998						
10101		2017-1301	5300 WEST LIFT STATION (SS17) CAPACITY IMPROVEMENTS	4	5	0	75,000	430,000				
10101	52490778	2015-0264	SOUTH LIFT STATION (SS05)	3	4	0			65,000	365,000		
10101		2015-0417	INDUSTRIAL LIFT STATION REHAB & PIPING UPGRADES (SS21)	4	5	0	70,000	710,000				
10101		2015-0267	NEW ROSE PARK LIFT STATION REPLACEMENT (SS02)	4	5	0	40,000	320,000				
10101	2015-0268	2015-0268	500 W LIFT STATION WET WELL IMPROVEMENTS (SS28)	4	5	0	50,000	425,000				
10101		2015-0274	PIONEER LIFT STATION WET WELL IMPROVEMENTS (SS20)	4	4	0			60,000	570,000		
10101		2015-0418	CENTENNIAL LIFT STATION WET WELL REHABILITATION (SS 19)	4	4	0			70,000	650,000		
10101		2015-0271	CANNON LIFT STATION WET WELL IMPROVEMENTS	4	4	0			40,000	375,000		
10101		2015-0270	WESTPOINTE LIFT STATION WET WELL IMPROVEMENTS (SS 33)	3	3	0						550,000
10101		2015-0272	900 NORTH LIFT STATION WET WELL IMPROVEMENTS	4	5	0	50,000	450,000				
		2017-2008	BILLY MITCHELL (SS16) CAPACITY IMPROVEMENTS	3	4	0			60,000	750,000		
	524907093	2017-2075	HUSKY LIFT STATION		4	2,600,000						
						4,047,918	510,000	2,560,000	425,000	2,840,000	130,000	1,070,000
	2720.30		**TREATMENT PLANTS**									
11201	524905347	2015-0640	FACILITY BUILDING PAINTING (CORROSION PROTECTION PROGRAM)	5	5	100,000	100,000	100,000	100,000	100,000	100,000	400,000
	524905338	2017-2093	INFLUENT SCREEN (S) REPLACE/RETROFIT	5	5	712,728	3,200,000					
	524905336		EXISTING FACILITES CONDITION ASSESSMENT/PRE-DESIGN		5	75,000						
	525400075		SOUTH RAS SKIMMER RELOCATION		4	14,615						
	52540066		WETLANDS RESTORATION PROJECT		4	0						
	524905342		PROCESS CONTROL LAB ROOM		4	19,221						
		2016-1275	WASHER COMPACTOR FOR PRIMARY SLUDGE	4	0	0		250,000				
	525400074	2017-2088	SCADA INSTRUMENTATION CONTROL IMPROVEMENTS	5	5	0						
~~11201~~	524905330	2015-0707	CHLORINE BUILDING ALARM SYSTEM		5	210,000						
		2018-1074	SCADA PHASE III FOLLOW-UP SERVICES	5	5	0	400,000					
~~11201~~	524905280	2015-0710	REPLACEMENT OF MCC2A AT THE PRE-SEDIMENTATION BUILDING - CONSTRUCTION		5	575,531						
11201	52540053	2015-0708	ATMOSPHERIC MONITORING REPLACEMENT PROGRAM	5	5	19,537		25,000	25,000	25,000	25,000	100,000
	52540064		VFD REPLACEMENT		5	227,208						
11201	52540052	2015-0500	TRICKLING FILTER REHABILITATION	5	5	0	650,000					2,000,000

SEWER UTILITY CIP BUDGET
Five Year Projected Budget FY2020-2024

COST CENTER	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	CRITICALITY RATING	CONDITION RATING	PAST YEAR SPENT 2018-19 (Calc'd from P6)	BUDGET YEAR 2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
	52540067		TRICKLIKNG FILTER PUMPS INSPECTION & RECONDITIONING			117,229						
11201	524905345	2015-0502	CAPITAL ASSET REHABILITATION AND UPGRADES	5	5	1,300,000	1,300,000	1,300,000	1,300,000	1,300,000	1,300,000	5,200,000
11201	2016-1133	2016-1133	REHAB OF VERTICAL TURBINE PUMPS	4	4	0				200,000		400,000
11201	524905344	2017-2089	HVAC REPLACEMENTS	3	3	25,000		25,000	25,000	25,000	25,000	100,000
	524905341		HVAC IMPROVEMENTS AT PRE-SEDIMENTATION			6,938						
		2016-1281	COGEN ENGINE OVERHAUL									700,000
		2018-1052	SLC WRF HEADWORKS GATE REPLACEMENT	5	5	0	250,000					
	524905334	2016-1160	UPGRADE EMERGENCY GENERATORS AT PUMP STATION	4	5	0	50,000					
		2018-1072	SLC WRF INFLUENT PUMP MOTOR REBUILD	5	4	0	120,000					
		2018-1071	SLC WRF INFLUENT PUMP REBUILD	5	4	0	200,000					
		2018-1068	SLC WRF BIO GAS HEAT EXCHANGER	4	4	0	75,000					
		2018-1066	SLC WRF PUMP PLANT EXTERIOR LIGHTING	4	5	0	35,000					
			NEW WATER RECLAMATION FACILITY									
	524905271		NEW PLANT - CORE DESIGN/BUILD RECLAMATION FACILITY	5	0	0	1,750,000	10,250,000	5,000,000	3,500,000	2,000,000	400,000
	524905335		WRF MASTER PLAN IMPLEMENTATION - CAPITAL PROJECT SUPPORT	5	0	1,500,000	4,500,000	4,500,000	4,500,000	3,500,000	3,500,000	4,000,000
11201	524905271		NEW PLANT - MECHANICAL DEWATERING (CONSTRUCTION)	5	0	0	33,500,000	440,000				
			NEW PLANT - BNR LIQUID STREAM (CONSTRUCTION)	5	0	0		41,020,000	#########	120,360,000	15,960,000	
			NEW PLANT - SOLIDS HANDLING (CONSTRUCTION)	5	0	0					41,160,000	2,840,000
			NEW PLANT - ADMIN OPS (CONSTRUCTION)	5	0	0		14,090,000	1,620,000			
			NEW PLANT - DEMOLITION (CONSTRUCTION)	5	0	0						6,500,000
	525400068	2017-2050	NEW PLANT - PROFESSIONAL DESIGN SERVICES	5	0	12,459,510	9,500,000	7,800,000	7,500,000	5,100,000	2,100,000	3,000,000
	524905339	2017-2051	NEW PLANT - CM/GC DESIGN SERVICES	5	0	488	3,000,000	2,500,000	1,000,000			
	524905337	2017-2052	NEW PLANT - WATER RENEW PUBLIC OUTREACH	5	0	250,000	300,000	250,000	250,000	250,000	250,000	500,000
	524905340	2017-2054	NEW PLANT - PILOTING AND DEMONSTRATION TESTING	5	0	98,947	2,000,000	2,000,000				
			NEW PLANT - PROJECT DOCUMENTATION	4	0	0	150,000	60,000	60,000	60,000	60,000	120,000
11201	524905272	2015-0404	NEW WATER RECLAMATION FACILITY - INFLUENT SCREENINGS (CONSTRUCTION)		5	0						
			TOTAL NEW WATER RECLAMATION FACILITY				54,700,000	82,910,000	#########	132,770,000	65,030,000	17,360,000
			TOTAL WATER RECLAMATION FACILITY			17,711,954	61,080,000	84,610,000	176,810,000	134,420,000	66,480,000	26,260,000
	2730.14		**COLLECTION LINES**									
			COLLECTION SYSTEM ASSET MANAGEMENT PROGRAM									
10401	52510020	2015-0704	1200 WEST TRUNK LINE CONDITION ASSESSMENT/ PROJECT PRE-DESIGN	5	2	0						600,000
10401	525002742	2015-0664	SIPHON INSPECTION PROJECT	4	2	0					100,000	
10401	525002834	2015-0647	COLLECTION SYSTEM PROJECT DEVELOPMENT CAP SCOPING	5	5	100,000	150,000	150,000	100,000	100,000	100,000	400,000
10401	525002770	2015-0703	BECK STREET TRUNK LINE CONDITION ASSESSMENT/PRE-DESIGN	5	2	232,403						600,000
10401	525002771	2015-0705	ORANGE STREET TRUNK LINE CONDITION ASSESSMENT/PROJECT PRE-DESIGN	5	2	0						500,000
						332,403	150,000	150,000	100,000	100,000	200,000	2,100,000
			FLOW MONITORING/I&I PROGRAM									
10401	525002756	2015-0648	WEST SIDE INFLOW & INFILTRATION STUDY		5	151,004						
10401	525002741	2015-0651	ANNUAL HYDRAULIC MODEL CALIBRATION	4	2	0				100,000		300,000

SEWER UTILITY CIP BUDGET
Five Year Projected Budget FY2020-2024

COST CENTER	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	CRITICALITY RATING	CONDITION RATING	PAST YEAR SPENT 2018-19 (Calc'd from P6)	BUDGET YEAR 2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
10401	525002740	2015-0649	PERMANENT FLOW METERS	5	0	350,000		250,000	250,000	250,000		
			VARIOUS BASIN INFLOW TESTING		4	0						
						501,004	0	250,000	250,000	350,000	0	300,000
			CITY, COUNTY, STATE AND MISC. DRIVEN PROJECTS									
10401	525002738	2015-0654	PRISON RELOCATION UTILITIES AND DEVELOPMENT SUPPORT		5	330,263						
	525002674		TERMINAL REDEVELOPMENT PROJECT	5	0		5,000	5,000				
10401	525002560	2015-0484	ANNUAL MISC. PUBLIC SERVICES PROJECTS	5	5	200,000	200,000	200,000	200,000	200,000	200,000	1,000,000
10401	525002738	2016-1262	NW QUADRANT CF INFRASTRUCTURE SUPPORT SERVICES	5	5	330,263	400,000	350,000				
	525002760		WEST TEMPLE - NORTH TEMPLE TO 400 SOUTH	4	5	673,778						
10401	525002764	2016-0743	1300 EAST - SEWER		5	285,900						
10401	2016-1265	2016-1265	NW QUADRANT (DEVELOPMENT) PIPE UPSIZE SEWER	5	0	0	350,000					
10401	525002681		WILMINGTON AVENUE SANITARY SEWER			15,082						
10401			MOUNTAIN VIEW CORRIDOR UDOT BETTERMENT			0	250,000					
			ODOR & CORROSION PRELIMINARY DESIGN AND SITING ANALYSIS	5	5	0	350,000					
			ODOR & CORROSION IMPLEMENTATION PROGRAM	5	0	0	50,000	1,500,000	1,500,000	1,500,000	1,500,000	4,500,000
			900 S (950 E TO 1300 E) ROADWAY	5	5	0	600,000					
			1900 EAST - WILMINGTON TO PARLEYS CANYON	5	5	0	450,000					
			700 W (1600 S TO 2100 S) ROADWAY	5	5	0	400,000					
			800 WEST 600 S to 800 S	5	5	0	250,000					
			500 EAST - 1700 SOUTH TO 2100 SOUTH	5	5	0	300,000					
			CITY WIDE STREET IMPROVEMENTS AND PRESERVATION 2019/2020	5	5	0	2,500,000					
			2000 E (PARLEYS CANYON BLVD TO CITY LIMIT) ROADWAY	5	5	0	200,000					
			300 W (900 S TO 2100 S) ROADWAY	5	5	0	150,000	2,000,000				
			900 EAST (HOLLYWOOD AVE TO 2700 S) ROADWAY	5	5	0		350,000				
			100 S (NORTH CAMPUS DRIVE TO 900 E) ROADWAY	5	5	0		500,000				
			1700 EAST (1700 S TO 2700 S) ROADWAY	5	5	0		550,000				
			CITY WIDE STREET IMPROVEMENTS AND PRESERVATION 2020/2021	5	5	0		2,500,000				
			300 WEST - 600 SOUTH to 2100 SOUTH	5	5	0			500,000			
			200 SOUTH - 400 WEST TO 900 EAST, PHASE 1	5	5	0			500,000			
			CITY WIDE STREET IMPROVEMENTS AND PRESERVATION 2021/2022	5	5	0			2,500,000			
			1100 EAST TO HIGHLAND - ROMONA AVE TO WARNOCK AVENUE	5	5	0				500,000		
			1100 EAST - 900 SOUTH TO RAMONA AVE	5	5	0				500,000		
			200 SOUTH - 400 WEST TO 900 EAST, PHASE 2	5	5	0				300,000		
			1300 EAST - 2100 SOUTH TO CITY BOUNDARY	5	5	0				500,000		
			CITY WIDE STREET IMPROVEMENTS AND PRESERVATION 2022/2023	5	5	0				2,500,000		
			VIRGINA STREET - SOUTH TEMPLE TO 11TH AVE	5	5	0					500,000	
			300 NORTH - 300 WEST TO 1000 WEST	5	5	0					500,000	
			CITY WIDE STREET IMPROVEMENTS AND PRESERVATION 2023/2024	5	5	0					2,500,000	
			900 SOUTH - 900 WEST TO 300 WEST AND WEST TEMPLE TO 900 EAST	5	5	0						1,000,000
			2100 SOUTH - 700 EAST TO 1700 EAST	5	5	0						500,000
			CITY WIDE STREET IMPROVEMENTS AND PRESERVATION 2023/2024	5	5	0						2,500,000
						1,835,286	6,455,000	7,955,000	5,200,000	6,000,000	5,200,000	9,500,000
			PIPE RENEWAL & REPLACEMENT PROGRAM									
10401	525002705	2015-0332	300 WEST - 500 NORTH TO 600 NORTH (WEST SIDE)		3	1,663						

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10401	525002708	2015-0333	WEST CAPITOL STREET - COLUMBUS STREET TO ZANE AVENUE TO WALL STREET		3	0						
10401	525002629	2015-0344	REDWOOD ROAD - PAXTON AVENUE TO CALIFORNIA AVENUE		3	96,755						
10401	525002780	2016-0840	4600 WEST DIVERSION I&I MITIGATION PROJECT		4	296,732						
	525002838		GLENDALE GOLF COURSE LATERAL			90,953						
10401		2015-0486	1% PER YEAR SEWER REHABILITATION/SYSTEM RENEWAL	5	5	0			2,650,000	3,000,000	3,000,000	20,000,000
	525002761	2015-0283	700 N I-15 BYPASS FOR INSPECTION OF EXISTING LINE	5	0	94,140	1,100,000					
10401	525002719	2015-0303	NORTH TEMPLE (100 N) - APPROX. 2050 WEST TO GLADIOLA STREET	5	5	150,000	2,100,000	200,000				
10401	2015-0722	2015-0722	TESORO SEWER TRUNK LINE REHABILITATION	5	4	0			250,000	6,000,000		
10401		2016-0897	WEST TEMPLE FROM TRUMAN AVE TO 1300 S CIPP	5	4	0				350,000	2,000,000	2,000,000
10401	2016-0902	2016-0902	800 S AND 1100 E LATERAL CONNECTIONS AND UPSTREAM INFILTRATION	3	4	0				20,000	150,000	
10401		2015-0727	300 W - 550 S TO 600 S	5	4	0					150,000	
10401	525002443	2016-0895	ELGIN AVE SEWER REPLACEMENT	3	3	0					400,000	
10401	2015-0318	2015-0318	700 SOUTH - 3750 WEST TO IRON ROSE PLACE (3830 W)	4	4	0					200,000	
	525002744	2016-0833	2300 EAST SEWER REHAB FROM EAST TO WEST SIDE OF FOOTHILL BLVD	5	5		60,000					
	525002774	2015-0728	ALLY BETWEEN LAKE ST AND 800 E	5	5		30,000					
	525002776	2015-0730	THIRD AVE FROM E ST TO F ST	5	5		30,000					
	525002836		OMNI AND STARCREST SEWER REHAB	5	5		50,000					
	525002858	2016-1050	CIPP SEWER ON 1675 E TOMAHAWK DR	5	5		100,000					
	525002772		WEST CAPITOL ST SANITARY SEWER MAIN FROM 490 N TO 520 N.	5	5		30,000					
10401	2016-0873	2016-0873	DOOLEY COURT	3	5	0	60,000					
	525002851	2017-2130	1200 WEST TRUNK LINE REHABILITATION PROJECT	5	5	400,106	1,000,000	4,000,000	4,000,000	4,000,000		
			BECK STREET TRUNK LINE REHABILITATION PROJECT	5	3	0					800,000	10,000,000
10401		2016-0908	3RD AVE D TO E STREET	3	5	0	140,000					
10401		2015-0731	MAIN ST - 320 N TO 340 N	4	5	0	110,000					
10401	525002355	2016-0861	6TH AVE FROM 588 E TO H ST	4	5	330,708	180,000					
10401	525002390	2016-0866	400 WEST FROM 100 NORTH TO 140 NORTH (WEST SIDE) CIPP INSTALLATION	3	4	0	40,000					
10401		2016-0989	2600 EAST AND BLAINE AVE REHABILITATION	3	5	0	150,000					
10401		2016-0991	CIPP SEWER ON FOOTHILL DR	3	5	0	110,000					
10401		2016-0992	WASATCH DR FROM 1300 SOUTH TO VILLAGE CIRCLE SEWER REHAB	3	5	0	260,000					
10401		2016-0993	FOOTHILL DR AND 1300 SOUTH SEWER REHAB	3	5	0	70,000					
10401		2016-0995	LOGAN WAY AND 1700 SOUTH SEWER REHAB	3	5	0	75,000					
10401		2016-0997	700 EAST FROM 2700 SOUTH TO CRYSTAL AVE SEWER REHAB	3	5	0	105,000					
10401		2016-0998	600 WEST 100 SOUTH SEWER REHAB	3	5	0	150,000					
10401		2016-1001	BROADMOOR ST FROM ELM AVE TO 2100 SOUTH SEWER REHAB	3	5	0	55,000					
10401		2016-1002	2300 EAST FROM STRINGHAM AVE TO BERNADINE DR SEWER REHAB	3	5	0	30,000					
10401		2016-1003	LYNWOOD DR SEWER REHAB	3	5	0	75,000					
10401		2016-1004	2300 EAST AND COUNTRY CLUB DRIVE SEWER REHAB	3	5	0	40,000					
10401		2016-1005	WILSHIRE CIRCLE SEWER REHAB	3	5	0	155,000					
10401		2016-1008	P STREET FROM 4TH AVE TO 3RD AVE SEWER REHAB	3	5	0	40,000					
10401		2016-1009	1ST AVE FROM T STREET TO U STREET SEWER REHAB	3	5	0	140,000					
10401		2016-1011	1200 EAST FROM FENWAY AVE TO 700 SOUTH SEWER REHAB	3	5	0	35,000					
10401		2016-1012	FULLER AVE FROM 1000 EAST TO 1100 EAST SEWER REHAB	3	5	0	35,000					
10401		2016-1013	500 SOUTH AND 1300 EAST SEWER REHAB	3	5	0	35,000					
10401		2016-1014	600 SOUTH 1300 EAST SEWER REHAB	3	5	0	45,000					
10401		2016-1016	1200 EAST AND 700 SOUTH SEWER REHAB	3	5	0	50,000					
10401		2016-1017	SUNNYSIDE AVE FROM CONNOR ST TO 2200 EAST SEWER REHAB	3	5	0	40,000					
10401		2016-1018	MICHIGAN AVE AND FOOTHILL BLVD SEWER REHAB	3	5	0	40,000					

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10401	525002829	2016-1019	FOOTHILL DRIVE AND 2100 EAST SEWER REHAB	3	5	0	90,000					
10401		2016-1020	LAIRD AVE SEWER REHAB	3	5	0	240,000					
10401	525002828	2016-1021	BROWNING AVE AND 1700 EAST	3	5	0	15,000					
10401	525002820	2016-1024	LOGAN AVE SEWER REHAB	3	5	0	100,000					
10401	525002800	2016-1026	1600 EAST FROM LOGAN AVE TO 1700 SOUTH SEWER REHAB	3	5	0	45,000					
10401		2016-1028	1900 EAST FROM 800 SOUTH AND 900 SOUTH SEWER REHAB	3	5	0	30,000					
10401		2016-1030	HARVARD AVE AND MCCLELLAND SEWER REHAB	3	5	0	90,000					
10401		2016-1031	BACKLOT BETWEEN PAXTON AVE AND FREMONT AVE SEWER REHAB	3	5	0	40,000					
10401		2016-1032	800 SOUTH FROM 700 EAST TO LAKE ST SEWER REHAB	3	5	0	85,000					
10401	525002804	2016-1035	2700 SOUTH AND IMPERIAL ST SEWER REHAB	3	5	0	100,000					
10401	525002809	2016-1036	JUDITH ST BETWEEN ZENNITH AVE AND HUDSON AVE SEWER REHAB	3	5	0	50,000					
10401	525002826	2016-1038	HOLLYWOOD AVE FROM 900 EAST TO LINCOLN ST SEWER REHAB	3	5	0	50,000					
10401	525002797	2016-1039	2100 SOUTH FROM 1900 EAST TO PRESTON ST SEWER REHAB	3	5	0	20,000					
10401		2016-1040	CIPP SEWER ON 800 EAST FROM SOUTH TEMPLE TO 100 SOUTH	3	5	0	10,000	100,000				
10401		2016-1041	CIPP SEWER ON 600 SOUTH FROM 500 EAST TO 600 EAST	3	5	0	5,000	50,000				
10401		2016-1042	CIPP SEWER ON 600 SOUTH 600 EAST	3	5	0	5,000	50,000				
10401		2016-1044	CIPP SEWER ON 300 WEST FROM ORCHARD PL TO 600 SOUTH	3	5	0	5,000	50,000				
10401		2016-1047	CIPP SEWER ON EMERSON AVE BETWEEN 2200 EAST AND 2300 EAST	3	5	0	6,500	65,000				
10401		2016-1048	CIPP SEWER ON ROOSEVELT AVE AND 2200 EAST	3	5	0	3,000	30,000				
10401		2016-1058	CIPP SEWER ON DARWIN ST FROM GIRARD AVE TO ZANE AVE	3	5	0	5,000	50,000				
10401		2016-1059	CIPP SEWER ON 1040 SOUTH BONNEVILLE DR	3	5	0	5,000	50,000				
10401		2016-1077	CIPP SEWER ON 1100 EAST BETWEEN 100 SOUTH AND 200 SOUTH	3	5	0	6,000	60,000				
10401		2016-1078	CIPP SEWER ON 200 SOUTH BETWEEN 900 EAST AND 1000 EAST	3	5	0	6,000	60,000				
10401		2016-1081	CIPP SEWER ON 1000 EAST BETWEEN 200 SOUTH AND 300 SOUTH	3	5	0	4,000	40,000				
10401		2016-1089	CIPP SEWER ALLEY WEST OF 600 E BETWEEN 800 SOUTH AND 900 SOUTH	3	5	0	20,000	200,000				
10401		2016-1090	CIPP SEWER ON GRACE CT AND WILLIAMS AVE	3	5	0	3,000	36,000				
10401		2016-1091	CIPP SEWER ON ALLEY EAST OF 300 EAST BETWEEN 800 SOUTH AND 900 SOUTH	3	5	0	3,000	36,000				
10401		2016-1093	CIPP SEWER ON 1700 EAST AND PARLEYS CANYON BLVD	3	5	0	3,000	36,000				
10401		2016-1094	CIPP SEWER ON FOURTH AVE FROM A STREET TO B STREET	3	5	0	3,000	36,000				
10401		2016-1096	CIPP SEWER ON THIRD AVE FROM E STREET TO F STREET	3	5	0	8,000	85,000				
10401		2016-1097	CIPP SEWER ON J STREET BETWEEN THIRD AVE AND FOURTH AVE	3	5	0	17,000	170,000				
10401		2016-1098	CIPP SEWER ON SECOND AVE BETWEEN F STREET AND G STREET	3	5	0	15,000	150,000				
10401		2016-1099	D STREET FROM FIRST AVE TO SECOND AVE SEWER REHAB	3	5	0	60,000					
10401		2016-1102	CIPP SEWER ON K STREET FROM SOUTH TEMPLE TO FIRST AVE	3	5	0	7,000	70,000				
10401		2016-1100	CIPP SEWER ON E STREET BETWEEN FIRST AVE AND SECOND AVE	3	5	0	4,000	40,000				
10401		2016-1103	CIPP SEWER ON 500 EAST BETWEEN SOUTH TEMPLE AND 100 SOUTH	3	5	0	10,000	105,000				
10401		2016-1104	CIPP SEWER ON SLADE PL AND 500 EAST	3	5	0	3,000	32,000				
10401		2016-1105	CIPP SEWER ON 300 SOUTH AND 300 EAST	3	5	0	65,000	642,000				
10401		2016-1110	CIPP ON A STREET BETWEEN SOUTH TEMPLE AND FIRST AVE	3	5	0	6,000	65,000				
10401		2016-1112	CIPP SEWER ON 200 EAST BETWEEN 200 SOUTH AND 300 SOUTH	3	5	0	6,000	60,000				
10401		2016-1113	CIPP SEWER ON 200 EAST BETWEEN 300 SOUTH AND 400 SOUTH	3	5	0	20,000	200,000				
10401		2016-1114	CIPP SEWER ON 200 WEST FROM 200 NORTH TO 300 NORTH	3	5	0	5,000	15,000				
10401		2016-1116	CIPP SEWER ON WEST TEMPLE BETWEEN 200 SOUTH AND 300 SOUTH	3	5	0	6,000	60,000				
10401		2016-1117	CIPP SEWER ON 200 SOUTH BETWEEN REGENT ST AND STATE ST	3	5	0	9,000	90,000				
10401		2016-1118	CIPP SEWER ON 200 SOUTH BETWEEN WEST TEMPLE AND MAIN ST	3	5	0	4,000	40,000				
10401		2016-1119	CIPP SEWER ON 400 SOUTH BETWEEN WEST TEMPLE AND MAIN ST	3	5	0	7,000	70,000				
10401		2016-1120	CIPP SEWER ON 400 SOUTH BETWEEN MAIN ST AND CACTUS ST	3	5	0	5,000	50,000				

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10401		2016-1121	CIPP SEWER ON MENLO AVE AND 800 EAST	3	5	0	6,000	60,000				17,000
10401		2016-1087	1700 SOUTH AND 1700 EAST SEWER REHAB	3	4	0			75,000			
10401		2016-1088	CIPP SEWER ON FAYETTE AVE AND WEST TEMPLE	3	4	0						17,000
10401		2016-1010	CIPP SEWER ON 1000 EAST FROM SOUTH TEMPLE TO 100 SOUTH	3	4	0						19,000
10401		2016-1101	CIPP SEWER ON B STREET BETWEEN SOUTH TEMPLE AND FIRST AVE	3	4	0						12,000
10401		2016-1109	CIPP SEWER ON ELY PL AND 700 EAST	3	4	0						20,000
10401		2016-1111	CIPP SEWER ON 200 EAST FROM 250 SOUTH TO 300 SOUTH	3	4	0						16,000
10401		2016-1115	CIPP SEWER ON 200 NORTH BETWEEN WEST TEMPLE AND ALMOND ST	3	4	0						11,000
10401		2016-1122	CIPP SEWER ON EDGEHILL ROAD AND LITTLE VALLEY ROAD	3	4	0						16,000
10401		2016-1123	CIPP SEWER ON 700 EAST EIGHTEENTH AVE	3	4	0						17,000
10401		2016-1124	CIPP SEWER ON NORTHMONT WAY AND EIGHTEENTH AVE	3	4	0						23,000
10401		2016-1126	CIPP SEWER ON TERRACE HILLS DR BETWEEN NORTHCREST DR AND NORTH BONNEVILLE	3	4	0						18,000
10401		2016-1129	CIPP SEWER ON H STREET BETWEEN ELEVENTH AVE AND TWELFTH AVE	3	4	0						13,000
10401		2016-1131	CIPP SEWER ON H STREET BETWEEN TENTH AVE AND ELEVENTH AVE	3	4	0						25,000
10401		2016-1132	CIPP SEWER ON NINTH AVE BETWEEN K STREET AND L STREET	3	4	0						21,000
10401		2016-1140	CIPP SEWER ON DORCHESTER DR FROM BRAEWICK RD TO SANDRUN RD	3	4	0						13,000
10401		2016-1142	CIPP SEWER ON B STREET FROM SIXTH AVE TO SEVENTH AVE	3	4	0						26,000
10401		2016-1144	CIPP SEWER ON 600 WEST FROM 400 NORTH TO 350 NORTH	3	4	0						21,000
10401		2016-1145	CIPP SEWER ON DONNER WAY FROM THACKERAY PL TO SHAKESPEARE PL	3	4	0						20,000
10401		2016-1152	CIPP SEWER ON KENSINGTON AVE AND BEACON DR	3	4	0						12,000
10401		2016-1153	CIPP SEWER ON CANTERBURY DR FROM LANCASTER DR TO WILTON WAY	3	4	0						25,000
10401		2016-1154	CIPP SEWER CANTERBURY DR AND LANCASTER DR	3	4	0						19,000
10401		2016-1155	CIPP SEWER 1515 SOUTH DEVONSHIRE DR TO LANCASTER DR	3	4	0						14,000
10401		2016-1156	CIPP SEWER ON UTE DR FROM INDIAN HILL CIRCLE TO EAGLE WAY	3	4	0						18,000
10401		2016-1157	CIPP SEWER ON COMANCHE DR AND EAGLE WAY	3	4	0						5,000
10401		2016-1158	CIPP SEWER ON WASATCH DR BETWEEN 1700 SOUTH AND SKYLINE DR	3	4	0						20,000
10401		2016-1172	CIPP SEWER FROM 1911 SOUTH FOOTHILL TO 1975 SOUTH FOOTHILL	3	4	0						19,000
10401		2016-1197	CIPP SEWER ON LOGAN WAY AT 1700 SOUTH	3	4	0						10,000
10401		2016-1198	CIPP SEWER ON BLAINE AVE AND TEXAS ST	3	4	0						15,000
10401		2016-1207	CIPP SEWER ON INDUSTRIAL AVE AND 1700 SOUTH	3	4	0						7,000
10401		2016-1209	CIPP SEWER ON 2300 EAST BETWEEN CLUBHOUSE DR AND MAYWOOD DR	3	4	0						18,000
10401		2016-1212	CIPP SEWER FROM 2526 EAST COMMONWEALTH TO WYOMING ST	3	4	0						20,000
10401		2016-1213	CIPP SEWER ON 2000 EAST BETWEEN WILSON AVE AND DOWNINGTOWN AVE	3	4	0						18,000
10401		2016-1214	CIPP SEWER FROM 1838 EAST DOWNINGTOWN AVE TO 1800 EAST	3	4	0						23,000
10401		2016-1215	CIPP SEWER ON 2100 EAST FROM WILSON AVE TO DOWNINGTOWN AVE	3	4	0						14,000
10401		2016-1216	CIPP SEWER ON 2000 EAST FROM DOWNINGTOWN AVE TO GARFIELD AVE	3	4	0						18,000
10401		2016-1218	CIPP SEWER ON 1700 SOUTH FROM 1860 EAST TO 1800 EAST	3	4	0						19,000
10401		2016-1219	CIPP SEWER ON 1700 EAST AND PARLEYS CANYON BL	3	4	0						4,000
10401		2016-1229	CIPP SEWER ON GLENMARE ST BETWEEN STRATFORD AVE AND 2700 SOUTH	3	4	0						19,000
10401		2016-1239	CIPP SEWER ON BEVERLY ST BETWEEN ATKIN AVE AND CLAYBOURNE AVE	3	4	0						17,000
10401		2016-1241	CIPP SEWER ON HUDSON AVE BETWEEN HIGHLAND DRIVE AND 1400 EAST	3	4	0						23,000
10401		2016-1242	CIPP SEWER ON SYLVAN AVE BETWEEN 1900 EAST AND 2000 EAST	3	4	0						22,000
10401		2016-1245	CIPP SEWER ON THIRD AVE AT CANYON ROAD	3	4	0						13,000
10401		2016-1246	CIPP SEWER ON STATE STREET BETWEEN 126 N AND 200 NORTH	3	4	0						19,000
10401		2016-1248	CIPP SEWER ON C STREET BETWEEN FIFTH AVE AND SIXTH AVE	3	4	0						24,000
10401		2016-1253	CIPP SEWER ON 300 NORTH BETWEEN 550 WEST AND 600 WEST	3	4	0						20,000
10401		2016-1256	CIPP SEWER ON UNIVERSITY BLVD (500 S) FROM 1500 EAST TO GUARDSMAN WAY	3	4	0						17,000

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10401		2015-0309	500 SOUTH - 3415 WEST TO 3600 WEST	3	3	0						224,000
10401		2016-0964	CIPP SEWER PIPE 1480 EAST TOMAHAWK DRIVE	3	3	0						12,000
10401		2016-0965	CIPP SEWER PIPE FROM 1536 E TOMAHAWK DR TO CHANDLER DR	3	3	0						20,000
10401		2016-0821	ELGIN AVE 1000 E - 950 E	2	4	0						200,000
10401		2017-1302	LEARNED AVE 1034 TO 1000 WEST	2	4	0						10,000
10401		2017-1307	2600 EAST 1750 TO 1889 SOUTH	2	4	0						50,000
10401		2016-0967	8-IN CIPP SEWER LINE FROM CAMBRIDGE WAY TO 1330 EAST PERRYS HOLLOW	3	3	0						9,000
10401		2016-0974	CIPP SEWER ON 1500 WEST FROM TALISMAN DR TO 895 NORTH	3	3	0						14,000
10401		2016-0977	CIPP SEWER BONNEVILLE DR	3	3	0						19,000
10401		2016-0980	CIPP SEWER ON OQUIRRH DRIVE	3	3	0						21,000
10401		2016-0982	CIPP SEWER AT ST MARY'S WAY AND OQUIRRH DRIVE	3	3	0						24,000
10401		2016-1006	CIPP SEWER ON 4TH AVE FROM VIRGINIA ST TO U ST	3	3	0						22,000
10401		2016-1007	CIPP SEWER ON FORT DOUGLAS CIRCLE	3	3	0						15,000
10401		2016-1015	CIPP SEWER ON BERKELEY ST AND WILMINGTON AVE	3	3	0						19,000
10401		2016-1049	CIPP SEWER ON TOMAHAWK DR	3	3	0						10,000
10401		2016-1051	CIPP SEWER ON 1675 EAST TOMAHAWK DR	3	3	0						13,000
10401		2016-1052	CIPP SEWER ON VIRGINIA ST FROM CHANDLER DR TO KRISTIANNA CIR	3	3	0						12,000
10401		2016-1053	CIPP SEWER ON KRISTIANNA CIR AND VIRGINIA ST	3	3	0						18,000
10401		2016-1054	CIPP SEWER ON ROUNDTOFT DR TO EAST CAPITOL BLVD	3	3	0						10,000
10401		2016-1062	CIPP SEWER ON SECOND AVE FROM L STREET TO M STREET	3	3	0						21,000
10401		2016-1092	CIPP SEWER ON 2100 SOUTH 1410 EAST	3	3	0						29,000
10401		2016-1127	CIPP SEWER ON 550 EAST NORTHHILLS DR	3	3	0						15,000
10401		2017-1305	1600 SOUTH INDUSTRIAL ROAD	1	5	0						25,000
10401		2016-0969	CIPP SEWER LINE ON 300 WEST FROM 400 NORTH TO BISHOP PL	3	2	0						1,000
10401		2016-1066	CIPP SEWER ON M STREET BETWEEN FIRST AND SECOND AVE	3	2	0						15,000
10401	525002849		1700 NORTH UNDER CITY DRAIN - BYPASS AND REHABILIATION	5	5	40,000	400,000					
			POINT REPAIR PROGRAM (VARIOUS LOCATIONS)									
10401	525002690	2015-0477	POINT REPAIRS IN SUPPORT OF CIPP PROGRAM (VARIOUS LOCATIONS)	3	5	0		350,000	350,000	350,000	350,000	1,400,000
			TOTAL COLLECTION LINES			1,501,058	8,475,500	7,503,000	7,325,000	13,720,000	7,050,000	37,188,000
			MANHOLE REHAB PROGRAM (VARIOUS LOCATIONS)									
10401		2015-0478	MANHOLE REHAB PROGRAM (VARIOUS LOCATIONS)	5	5	0	450,000	350,000	350,000	350,000	350,000	2,100,000
	525002832		500 SOUTH SURPLUS SIPHON VAULT REPLACEMENT (MH 05225)		5	90,779	400,000					
						90,779	850,000	350,000	350,000	350,000	350,000	2,100,000
			OTHER PROJECTS									
10401	525002839	2015-0376	ON-CALL TASK ORDER GENERAL CONSTRUCTION SERVICES (VARIOUS LOCATIONS)		5	300,000						
10401	52520035	2015-0485	CONTRIBUTIONS BY DEVELOPERS	5	5	0	500,000	500,000	500,000	500,000	500,000	2,000,000
	52510023	2016-1267	COLLECTION SYSTEM PROJECTS GENERAL SUPPORT - TASK 2	5	0	1,500,000	2,000,000	2,000,000	1,500,000	1,500,000	750,000	750,000
	525002786		PROGRAM MANAGEMENT SERVICES - TASK 1			0	350,000	350,000	350,000	350,000	350,000	350,000
		2016-0839	TDS REDUCTION PROGRAM	1	0	0						500,000
						1,800,000	2,850,000	2,850,000	2,350,000	2,350,000	1,600,000	3,600,000
			MASTER PLAN IMPLEMENTATION PROGRAM									

SEWER UTILITY CIP BUDGET
Five Year Projected Budget FY2020-2024

COST CENTER	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	CRITICALITY RATING	CONDITION RATING	PAST YEAR SPENT 2018-19 (Calc'd from P6)	BUDGET YEAR 2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
10401	525002524	2015-0279	500 SOUTH INTERCEPTOR - ORANGE TO 1000 WEST		5	1,720,290						
10401	525002698	2015-0286	MP12A - 700 SOUTH CAPACITY UPGRADES – 4650 WEST TO 3400 WEST	5	5	14,004,129	250,000					
10401	52490785	2016-1260	500 SOUTH DIVERSION, PHASE II (PUMP STATION)	5	5	11,976,147	2,000,000					
10401	525002850	2016-0950	MP13 - BECK STREET TRUNK REPLACEMENT FROM 500 SOUTH AND STATE STREET TO 700 S(	5	5	522,328	1,000,000	6,000,000	11,000,000			
10401	525002376		1800 NORTH BECK STREET TO THE PRETREATMENT PLANT	5	5	2,608,982	3,000,000	12,000,000	6,000,000			
10401	525002423	2015-0320	MP8A - 1500 SOUTH - 2700 WEST TO REDWOOD ROAD	4	5	840,877	500,000					
10401	525002631	2015-0280	ORANGE STREET - PHASE IV - INDIANA TO 1500 SOUTH	5	4	0						6,131,000
10401	52490787	2015-0269	MP12D - 700 SOUTH LIFT STATION (SS 10)	5	4	493,341	7,000,000					
10401	2016-0929	2016-0929	MP16 - 600 WEST AND 700 SOUTH TO 500 WEST AND 800 SOUTH	5	4	0					1,400,000	
10401	2016-0930	2016-0930	MP17A - 900 SOUTH FROM RICHARD STREET TO MAIN STREET	5	4	0	250,000	1,000,000				
10401	2016-0931	2016-0931	MP17B - MAIN STREET FROM 800 SOUTH TO 900 SOUTH	5	4	0						809,100
10401	2016-0932	2016-0932	MP18 - 300 WEST FROM FAYETTE AVE TO 900 SOUTH	5	4	0						800,000
10401	2016-0940	2016-0940	MP19 - FOLSOM AVENUE FROM 500 WEST TO 1000 WEST	5	4	0						13,500,000
10401	2016-0941	2016-0941	MP20 - 700 WEST FROM 900 SOUTH TO 600 SOUTH	5	4	0						5,500,000
10401	2016-0942	2016-0942	MP21 - 100 SOUTH AND 300 WEST DIVERSION	5	4	0						300,000
10401		2015-0284	500 S SEWER REPLACEMENT FROM 3200 W TO ORANGE STREET	4	4	0						17,150,000
10401	2015-0322	2015-0322	MP28 - NORTH TEMPLE - AIRPORT TO ORANGE STREET	4	4	0					750,000	15,500,000
10401	2016-0949	2016-0949	MP26 - SOUTH TEMPLE AND 400 WEST DIVERSION	4	4	0						250,000
10401	525002577	2016-0849	MP15 - 700 SOUTH INTERCEPTOR CAPACITY UPGRADE	4	4	508,500	3,000,000	500,000				
10401	525002584	2016-0905	MP7 - 100 SOUTH 1200 EAST DIVERSION FOR CAPACITY	4	4	0	400,000					300,000
10401	2016-0943	2016-0943	MP22 - PIONEER ROAD FROM CALIFORNIA AVENUE TO 1500 SOUTH	4	4	0				1,500,000	6,500,000	1,000,000
10401	2016-0947	2016-0947	MP24 - 400 SOUTH FROM 300 WEST TO 600 WEST	4	4	0						3,000,000
10401	2016-0953	2016-0953	MP31 - 600 SOUTH FROM 800 WEST TO 900 WEST	4	3	0						2,000,000
10401	525002507	2015-0321	MP8B - 3230 WEST - 1820 SOUTH TO 1670 SOUTH	3	4	397,056				1,000,000	5,000,000	
10401	2016-0952	2016-0952	MP30 - 200 EAST FROM 300 SOUTH TO 500 SOUTH	4	3	0						2,000,000
10401		2016-0946	MP23 - PARALLEL 1000 WEST 48-INCH TRUNK	4	3	0						20,000,000
10401	2016-1195	2016-1195	MP29 - BECK STREET TRUCK REPLACEMENT FROM 200 SOUTH AND 300 WEST TO STATE STR	4	3	0						16,000,000
10401		2016-0841	500 S. PUMP AND THIRD FORCE MAIN INSTALLATION	5	1	0						10,000,000
10401	2016-0954	2016-0954	MP32 - 700 WEST FROM 700 SOUTH TO 500 SOUTH (EAST SIDE OF I-15)	3	3	0						3,000,000
10401	2016-0955	2016-0955	MP33 - 1300 EAST FROM 400 SOUTH TO 500 SOUTH	3	3	0	450,000					
10401		2015-0660	SATELLITE TREATMENT PLANT	5	0	0						405,500,000
10401			700 S. PUMP AND THIRD FORCE MAIN INSTALLATION			0						10,000,000
						33,071,650	17,850,000	19,500,000	17,000,000	2,500,000	13,650,000	532,740,100
			Total Collection System			39,132,179	36,630,500	38,558,000	32,575,000	25,370,000	28,050,000	587,528,100
	2730.20		**LANDSCAPING**									3,372,750
10401	525002689		NORTHWEST OIL DRAIN			0	150,000					
						0	150,000	0	0	0	0	3,372,750
			TOTAL CAPITAL IMPROVEMENTS			60,892,051	98,370,500	125,728,000	210,160,000	162,630,000	94,660,000	618,230,850

SEWER UTILITY CAPITAL PURCHASES BUDGET
Five Year Projected Budget FY2020-2024

COST CENTER	OBJECT CODE	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	Comments	CRITICALITY RATING	CONDITION RATING	PAST YEAR 2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
	2710.10			LAND										
5210401			2015-0481	500 SOUTH LAND PURCHASE		5	5		4,100,000					
5210401				LAND EASEMENT FOR 700 SOUTH SEWER LINE		4	4							
5210401			2016-0887	SHURTLEFF AND ANDREWS SECONDARY ACCESS		4	4		500,000					
5210401				LAND EASEMENT FOR 500 SOUTH MP PROJECT TO ORANGE STREET		4	4		1,000,000					
5210401			2016-0870	EASEMENT NORTH OF OQUIRRH DR		4	4							
								0	5,600,000	0	0	0	0	0
	2750.10			AUTOMOBILES & TRUCKS										
5212201	2750.10			Electric Club Car Qty. 4										
5210801	2750.10			Transit Van w/Upfit										
5210101	2750.10			3/4 Ton Truck w/Service Body 4X4										
5210601	2750.10		3387	Int. 1 ton Cab-n-Chassis w/ Dump Bed				47,157						
5210101	2750.10		36910	GMC 3/4 ton Ext Cab Pick-up Truck				56,165						
5211201	2750.10		3418	Chev 3/4 ton Ext Cab Pick-up Truck				34,390						
5211201	2750.10		3425	Chev 1 ton Cab-n-Chassis Util. Bed & Crane				31,640						
5211201	2750.10		3488	GMC 1/2 ton Cab-n-Chassis w/ Utility Body				30,031						
5212201	2750.10		49/63/58/62	Golf Cart Enclosed Cab Dump Bed Qty 4				56,000						
5210401	2750.10			CHEV OR SIMILAR MID-SIZED 4X4 PICK UP W/BED COVER	Jason				30,000					
5212201	2750.10		3428	Replace Volvo Wg64, Mack Granite 64 br	Jamey				190,000					
5212201	2750.10		34030	Replace Stering LT9500, Mack Granite 64 br	Jamey				190,000					
5212201	2750.10		34310	Replace International 2674 6x4, Mack Granite 64 br	Jamey				190,000					
5212201	2750.10		34020	Replace International 7400 4x2, Vactor	Jamey				500,000					
5212301	2750.10		3485	Replace Ford F-350, Chevrolet Silverado 3500HD 4x4	Jamey				40,000					
5212301	2750.10		3458	GMC Sierra 3500HD Flatbed Dump	Jamey				49,000					
5210601	2750.10		33080	Mack GU713	Randy				460,000					
5210601	2750.10		33880	GMC Sierra 2500	Randy				31,000					
5210101	2750.10		33890	GMC Sierra 2500 W/Service Body	Randy				37,500					
5212301				VARIOUS										
								255,383	1,717,500	0	0	0	0	0
	2750.30			FIELD MAINTENANCE EQUIP.										
5210601				BACKHOE EXCHANGE				8,000	8,000	8,000	8,000	8,000	8,000	
5210801				REHAB OLD CCTV VAN										
5210601				VARIOUS					400,000	400,000	400,000	400,000	400,000	
5210601				PUMP TRUCK - LARGE DIAMETER PIPE CLEANING MACHINE										
5210601				Cat Backhoe Buyback Program				9,000						
5211201				40 Ton Rough Terrain Crane for Water Rec				462,403						
5210601				BOBCAT SKID STEER										
								479,403	408,000	408,000	408,000	408,000	408,000	0
	2760.10			PUMP PLANT EQUIPMENT										

SEWER UTILITY CAPITAL PURCHASES BUDGET
Five Year Projected Budget FY2020-2024

COST CENTER	OBJECT CODE	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	Comments	CRITICALITY RATING	CONDITION RATING	PAST YEAR 2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
5211201	2760.10			SLC WRF Pump Plant Exterior Lighting Upgrades	Michael				35,000					
5211201	2760.10			SLC WRF Influent Pump Discharge Ball Valves	Michael				200,000					
									235,000	0	0	0	0	0
	2760.20			TREATMENT PLANT EQUIPMENT										
5212201	2760.20			COMPRESSORS AND BLOWERS										
5212201	2760.20			PUMPS										
5211201	2760.20			AERATION BASIN DRAINAGE PUMP REPLACEMENTS (10)				100,000						
5211201	2760.20			REPLACEMENT #2 WATER PUMP				100,000						
5211201	2760.20			PUMP PLANT GRIT PUMP REPLACEMENT (2)				6,778						
5211201	2760.20			SUPPLIED AIR SYSTEM REPLACEMENT CL2 BLDG				20,000						
5211201	2760.20			DIGESTER ROOF WALK WAY IMPROVEMENTS				10,000						
5211201	2760.20			HVAC REPLACEMENTS (3)				120,000						
5211101	2760.20			XPE205 METTLER TOLEDO ANALYTICAL BALANCE										
5211101	2760.20			LACHAT/HATCH 2-CHANNEL FIA + IC CONFIGURATION										
5211201	2760.20			Primary Trickling Filter Overflow Gate	Michael				20,000					
5211201	2760.20			SLC WRF HVAC Improvements	Michael									
5211201	2760.20			East Maitenance	Michael				18,000					
5211201	2760.20			Pre Treatment	Michael				5,500					
5211201	2760.20			Switch Gear #3	Michael				5,500					
5211201	2760.20			Chillers (2)	Michael				80,000					
5211201	2760.20			Administration	Michael				40,000					
5211201	2760.20			Digester MCC Room	Michael				5,000					
5211201	2760.20			South Ras	Michael				5,500					
5211201	2760.20			North Ras	Michael				5,500					
5211201	2760.20			TWAS Electrical Room	Michael				5,500					
5211201	2760.20			All Swamp Coolers (6)	Michael				27,000					
5211201	2760.20			SLC WRF Grease Pump	Michael				20,000					
5211201	2760.20			SLC WRF Snail Pump	Michael				15,000					
5211201	2760.20			SLC WRF Trickling Filter Motor VFD Replacement (6)	Michael				6,000					
5211201	2760.20			SLC WRF Bio Gas Heat Exhanger Upgrade	Michael				75,000					
5211201	2760.20			SLCWRF Co-Gen Controls	Michael				50,000					
5211201	2760.20			SLCWRF #2 Water Filters (2)	Michael				90,000					
5211201	2760.20			SLCWRF Co-Gen Oil Filter Replacement (2)	Michael				70,000					
5212201				VARIOUS						225,000	225,000	225,000	225,000	
								356,778	543,500	225,000	225,000	225,000	225,000	450,000
	2760.30			TELEMETERING EQUIPMENT										
5211201	52540048			TELEMETERING UPGRADE - REPLACE										
5210101				SCADA SYSTEM REPLACE				10,000	10,000	10,000	10,000	10,000	10,000	
								10,000	10,000	10,000	10,000	10,000	10,000	20,000
	2760.50			OFFICE FURNITURE & EQUIPMENT										

SEWER UTILITY CAPITAL PURCHASES BUDGET
Five Year Projected Budget FY2020-2024

COST CENTER	OBJECT CODE	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	Comments	CRITICALITY RATING	CONDITION RATING	PAST YEAR 2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
5211301				Server replacement "SLCIWRDB"				9,000						
5211701				Core Switch										
5212401				FULL FUNCTION PRINTER REPLACEMENT PRE-TREATMENT SMALL				5,765						
5212201				VARIOUS				20,000	20,000	20,000	20,000	20,000	20,000	
								34,765	20,000	20,000	20,000	20,000	20,000	20,000
	2760.90			OTHER NON-MOTIVE EQUIPMENT										
5210601				TOW ALONG CEMENT MIXER										
5212201				STATIONARY SAMPLER W/ENCLOSURE										
5212401				VARIOUS NON-MOTIVE EQUIPMENT					160,000	160,000	160,000	160,000	160,000	
5212201				UPGRADE LAB ANALYTICLA EQUIPMENT										
5212201				Washer Compactor for Primary Sludge Screens										
5210601				Vanguard System										
5210601				HANDHELD RADIO REPLACEMENT				57,902						
5210801				REPLACEMENT PUSH CAMERA				11,000						
5210801				NEW LATERAL LAUNCH ADD ON SYSTEM				67,338						
5211101				LABORATORY SPECTROPHOTOMETER REPLACEMENT				5,000						
5211101				LABORATORY DIGITAL BALANCE REPLACEMENT				5,000						
5211401				SURVEY GRADE GPS UNIT				20,000						
								166,240	160,000	160,000	160,000	160,000	160,000	0
				TOTAL CAPITAL OUTLAY				**1,302,569**	**8,694,000**	**823,000**	**823,000**	**823,000**	**823,000**	**490,000**

Stormwater Utility- Budget Summary and Cash Flow

STORMWATER UTILITY
ENTERPRISE FUND
BUDGET SUMMARY
FY 2020-2022

SOURCES	ACTUAL 2017-18	AMENDED BUDGET 2018-19	PROJECTED ACTUAL 2018-19	Rate increase 10% PROPOSED BUDGET 2019-20	Rate increase 10% FORECAST BUDGET 2020-21	Rate increase 10% FORECAST BUDGET 2021-22
REVENUES						
METERED SALES	$ 8,508,507	$ 8,855,000	$ 8,855,000	**$ 9,740,500**	$ 10,714,550	$ 11,678,860
INTEREST INCOME	124,773	33,000	33,000	**20,820**	174,816	38,338
OTHER REVENUES	1,027,830	1,000	1,000	**1,000**	1,000	1,000
TOTAL REVENUES	$ 9,661,110	$ 8,889,000	$ 8,889,000	**$ 9,762,320**	$ 10,890,366	$ 11,718,198
OTHER SOURCES						
GRANTS & OTHER RELATED REVENUES	354,475	650,000	650,000	**516,000**	516,000	516,000
COUNTY FLOOD CONTROL	-	-	-	**-**	-	-
IMPACT FEES	366,456	200,000	200,000	**200,000**	200,000	200,000
SHORT-TERM FINANCING	-	1,355,000	-	**-**	-	-
BOND PROCEEDS	-	-	-	**14,581,000**	-	6,159,200
TOTAL OTHER SOURCES	$ 720,931	$ 2,205,000	$ 850,000	**$ 15,297,000**	$ 716,000	$ 6,875,200
TOTAL SOURCES	$ 10,382,041	$ 11,094,000	$ 9,739,000	**$ 25,059,320**	$ 11,606,366	$ 18,593,398
EXPENSES & OTHER USES						
EXPENDITURES						
PERSONNEL SERVICES	$ 2,390,383	$ 2,872,608	$ 2,872,608	**3,187,954**	$ 3,315,474	$ 3,448,092
OPERATING & MAINTENANCE	152,863	186,450	186,450	**200,950**	204,769	208,864
TRAVEL & TRAINING	7,009	12,750	12,750	**16,265**	16,590	16,922
UTILITIES	188,079	244,045	244,045	**244,045**	248,926	253,903
TECHNICAL SERVICES	632,693	2,141,221	2,141,221	**1,304,999**	1,230,399	1,241,007
PUBLIC SERVICES / STREET SWEEPING	819,605	819,605	819,605	**819,605**	835,997	852,717
DATA PROCESSING	317,811	239,700	239,700	**304,000**	310,080	316,282
FLEET MAINTENANCE	223,731	214,000	214,000	**214,000**	218,280	222,645
ADMINISTRATIVE SERVICE FEE	101,615	130,000	130,000	**120,000**	122,400	124,848
PAYMENT IN LIEU OF TAXES	109,785	125,942	125,942	**100,434**	102,443	104,492
BILLING COST	423,849	554,117	554,117	**545,417**	556,325	567,452
RISK MANAGEMENT	57,985	86,983	86,983	**84,842**	86,539	88,269
TRANSFERS TO GENERAL FUND	-	4,000	4,000	**4,000**	4,080	4,162
OTHER CHARGES AND SERVICES	98,689	27,899	27,899	**25,857**	27,101	27,641
TOTAL EXPENDITURES	$ 5,524,097	$ 7,659,320	$ 7,659,320	**$ 7,172,368**	$ 7,279,403	$ 7,477,296
OTHER USES						
CAPITAL OUTLAY	197,620	515,568	515,568	**728,149**	620,000	620,000
CAPITAL IMPROVEMENT BUDGET	2,392,384	6,522,769	3,783,053	**12,744,000**	7,630,000	4,371,000
COST OF DEBT ISSUANCE	-	10,000	-	**81,000**	-	34,200
DEBT SERVICES	1,017,494	1,014,000	1,014,000	**1,225,000**	1,649,000	1,652,000
TOTAL OTHER USES	$ 3,607,498	$ 8,062,337	$ 5,312,621	**$ 14,778,149**	$ 9,899,000	$ 6,677,200
TOTAL USES	$ 9,131,595	$ 15,721,657	$ 12,971,941	**$ 21,950,517**	$ 17,178,403	$ 14,154,496
EXCESS REVENUE AND OTHER SOURCES OVER (UNDER) USES	$ 1,250,446	$ (4,627,657)	$ (3,232,941)	**$ 3,108,803**	$ (5,572,037)	$ 4,438,902
OPERATING CASH BALANCES						
BEGINNING JULY 1	$ 5,316,077	$ 6,566,523	$ 6,566,523	**$ 3,333,582**	$ 6,442,385	$ 870,348
ENDING JUNE 30	$ 6,566,523	$ 1,938,866	$ 3,333,582	**$ 6,442,385**	$ 870,348	$ 5,309,250
Cash Reserve Ratio	119%	25%	44%	90%	12%	71%

Cash reserve goal above 10%

STORMWATER UTILITY
CASH FLOW
FY 2020 BUDGET
AND FY 2021-2024 FORECAST

10%,10%,9%,6%,5% Rates
$20.6M in Bonds,$14.5M FY20 and $6.2M FY22
New Debt Pmts $3.1M thru FY24
100% Capital Budget FY 20 thru 24

	ACTUAL YEAR 2017-2018	PROJECTED YEAR 2018-2019	BUDGET YEAR 2019-2020	BUDGET YEAR 2020-2021	BUDGET YEAR 2021-2022	BUDGET YEAR 2022-2023	BUDGET YEAR 2023-2024
STORMWATER CHARGES	8,508,507	8,855,000	9,740,500	10,714,550	11,678,860	12,379,591	12,998,571
OTHER INCOME	1,027,830	1,000	1,000	1,000	1,000	1,000	1,000
INTEREST INCOME	124,773	33,000	20,820	174,816	38,338	106,254	51,104
OPERATING INCOME	9,661,110	8,889,000	9,762,320	10,890,366	11,718,198	12,486,845	13,050,675
OPERATING EXPENDITURES	(5,524,097)	(7,659,320)	(7,172,368)	(7,279,403)	(7,477,296)	(7,681,804)	(7,343,160)
NET INCOME EXCLUDING DEP.	4,137,013	1,229,680	2,589,952	3,610,963	4,240,902	4,805,041	5,707,515
IMPACT FEES	366,456	200,000	200,000	200,000	200,000	200,000	200,000
SHORT-TERM FINANCING							
NET BOND PROCEEDS			14,500,000		6,125,000		
COST OF ISSUANCE (PROCEEDS)		0	81,000	0	34,200	0	0
COST OF ISSUANCE (EXP.)		0	(81,000)	0	(34,200)	0	0
OTHER CONTRIBUTIONS	354,475	650,000	516,000	516,000	516,000	516,000	516,000
CAPITAL OUTLAY	(197,620)	(515,568)	(728,149)	(620,000)	(620,000)	(620,000)	(620,000)
SHORT-TERM DEBT							
DEBT SERVICE (NEW)		0	(213,000)	(638,000)	(638,000)	(638,000)	(925,000)
DEBT SERVICE	(1,017,494)	(1,014,000)	(1,012,000)	(1,011,000)	(1,014,000)	(1,009,000)	(1,018,000)
OTHER INCOME & EXPENSE	(494,183)	(679,568)	13,262,851	(1,553,000)	4,569,000	(1,551,000)	(1,847,000)
GENERATED FOR CAPITAL	3,642,830	550,112	15,852,803	2,057,963	8,809,902	3,254,041	3,860,515
CAPITAL IMPROVEMENTS	(2,392,384)	(3,783,053)	(12,744,000)	(7,630,000)	(4,371,000)	(7,023,000)	(4,300,000)
BEGINING CASH BALANCE	5,316,077	6,566,523	3,333,582	6,442,385	870,348	5,309,250	1,540,291
CASH INCREASE/(DECREASE)	1,250,446	(3,232,941)	3,108,803	(5,572,037)	4,438,902	(3,768,959)	(439,485)
ENDING BALANCES	6,566,523	3,333,582	6,442,385	870,348	5,309,250	1,540,291	1,100,806
AMOUNT RESTRICTED							
DEBT SERVICE COVERAGE	**4.07**	**1.21**	**2.11**	**2.19**	**2.57**	**2.92**	**2.94**
RATE CHANGE	0%	10%	10%	10%	9%	6%	5%
Cash Reserve Ratio	**119%**	**44%**	**90%**	**12%**	**71%**	**20%**	**0**
Minimum Reserve	**552,410**	**765,932**	**717,237**	**727,940**	**747,730**	**768,180**	**734,316**
Ending Reserve Available for Capital	**6,014,113**	**2,567,650**	**5,725,148**	**142,408**	**4,561,520**	**772,111**	**366,490**
DEBT SERVICE % OF GROSS OPERATING REVENU	**11%**	**11%**	**13%**	**15%**	**14%**	**13%**	**15%**
RESIDENTIAL BILL FOR 1 ERU (or .25 acre)	**4.49**	**4.94**	**5.43**	**5.97**	**6.51**	**6.90**	**7.25**

STORMWATER CIP BUDGET
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COST CENTER	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	CRITICALITY RATING	CONDITION RATING	PAST YEAR 2018-19 (Calc'd from P6)	BUDGET YEAR 2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
53-10301	2720.05		**LIFT STATIONS**									
10301	53471046	2015-0434	LIFT STATION REHABILITATION AT 400 WEST AND 1300 SOUTH - NORTH SIDE	5	4	171,097						400,000
10301	53470852		LIFT STATION AT SURPLUS CANAL AND INDIANA REPAIRS	4	5	7,501						
10301	53471040		SWEDE TOWN LIFT STATION	3	0	40,514		700,000				
10301	534710104	2015-0435	VARIOUS PUMP STATIONS	5	5	50,000	50,000	50,000	50,000	50,000		
10301	53471038	2015-0140	OIL DRAIN LIFT STATION - GABION BASKETS RECONSTRUCTION	5	4	0						58,000
10301	534710103	2015-0135	SD LIFT STATION AT 650 WEST AND 500 NORTH IMPROVEMENTS	4	4	15,000	14,000					107,500
10301		2015-0144	HARTLAND LIFT STATION ABANDONMENT	1	5	0						50,000
10301		2015-0145	300 WEST 1300 SOUTH LIFT STATION ABANDONMENT	1	2	0						50,000
						$ 284,112	$ 64,000	$ 750,000	$ 50,000	$ 50,000	$ -	$ 665,500
53-10301	2730.20		**DETENTION BASINS**									
53-10301	2730.12		**COLLECTION MAINS**									
	53470882	2017-2101	LEE DRAIN - PIPE OPEN CHANNEL WEST OF PIONEER ROAD	5	4	60,000		700,000				
	53470974		ORANGE STREET STORM DRAIN - NORTH TEMPLE TO I-80	5	0	45,000						500,000
	53470835	2015-0142	MIDDLE BRIGHTON RAILROAD CULVERT REHABILITATION	5	4	0		20,000				260,000
		2017-2034	RED BUTTE CREEK CULVERT AT 900 SOUTH - LINER	5	4	0					300,000	
	534701001	2017-2100	PIPE REPLACEMENT AT 750 S 1100 EAST	4	5	3,000						
	534700998	2016-0746	ABANDONMENT OF STORMWATER DITCH FROM WARM SPRINGS ROAD TO THE NORTHWEST DRAIN	4	4	10,000	60,000	250,000				
	534700997	2017-2098	PIPE REPLACEMENT AT 746 SOUTH ELIZABETH	3	5	5,250						
		2015-0131	REPAIR OUTLETS ON THE LEE DRAIN AT 4800 WEST	3	4	0			21,000	170,000		
	53470970	2016-0853	DITCH BANK EROSION PROTECTION - 600 NORTH 550 WEST	2	3	6,039	10,000	60,000				
	53470937	2015-0130	WQ - MONTAGUE CUTOFF- NEW 18" STORM DRAIN	4	0	0						61,500
		2015-0584	FOOTHILL DRIVE (2800 E) – EMIGRATION CREEK TO 2300 EAST	4	0	0						500,000
	53470881	2015-0143	1500 EAST STORM DRAIN	3	0	0				203,000		
	534701000	2016-0750	1700 SOUTH STORM DRAIN, FROM 2100 EAST TO EMIGRATION CREEK	3	0	211,811	1,100,000	1,100,000				
		2015-0585	600 EAST – 900 SOUTH TO THE AVENUES	2	0	0						4,200,000
	53470995		PARLEY CREEK STORM WATER OUTFALL			11,766						
	53470994		CITY DRAIN CROSSING AT HUNTER STABLES			259,175						
	534701013		1700 S 18" STORM DRAIN FROM 1700 E TO 1900 E			399,000						
	53470988		7200 WEST AND NORTH TEMPLE CULVERT REPLACEMENT AND CANAL REHAB			0	250,000					
		2016-0855	NORTHWEST QUADRANT STORMWATER BETTERMENTS	5	5	0						14,000,000
		2018-1040	PIPING OF GOGGIN DRAIN AT HAROLD GATTY DRIVE	3	4	0						335,300
						$ 1,011,040	$ 1,420,000	$2,130,000	$ 21,000	$ 373,000	$ 300,000	$19,856,800
			CITY, COUNTY, STATE AND MISC. DRIVEN PROJECTS									
	53470979		PROGRAM MANAGEMENT TOOLS	5	5	0	150,000					
10301	53470947	2016-0736	INDIANA AVENUE STORM DRAIN REDWOOD ROAD TO 3400 WEST	4	0	128,175						
10301	53470972		GLADIOLA AVE PHASE 1 - 500 SOUTH TO 900 SOUTH			869,550						
10301	53470946	2015-0436	STORM DRAIN CITY/COUNTY/STATE PROJECTS	5	5	0	150,000	150,000	150,000	150,000	150,000	
10301	534720005	2017-2033	STORMWATER RECIEVING STATION	4	4	9,000	150,000					
10301	53470971	2016-0741	1300 EAST - STORM DRAIN	3	4	377,165	1,200,000					
	53470936	R18-0054	NEW STORM DRAIN ON 5500 WEST FROM 700 SOUTH CUL-DE-SAC TO THE NORTH			111,515	1,500,000					
10301	513000039	2015-0723	SURPLUS CANAL ENCROACHMENT AND PERMITTING	5	5	25,000	50,000	50,000	50,000	50,000	50,000	
			700 SOUTH SD, MIDDLE BRIGHTON TO 5600 WEST			0	800,000	800,000	800,000			
			2700 SOUTH - HIGHLAND TO 20TH EAST			0	250,000					
			1500 SOUTH - REDWOOD TO 2700 WEST			0	800,000					
		s	OVERLAY - VARIOUS			0			750,000	750,000		

STORMWATER CIP BUDGET
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COST CENTER	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	CRITICALITY RATING	CONDITION RATING	PAST YEAR 2018-19 (Calc'd from P6)	BUDGET YEAR 2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
	534700999	2015-0126	700 WEST - 2100 SOUTH TO 1700 SOUTH - PIPING OF OPEN DITCH	4	3	0	1,000,000					
			LOCAL STREET DISTRICT 1 & 7			0	500,000					
			500 EAST - 1700 SOUTH TO 2700 SOUTH			0	800,000					
			2000 EAST - PARLEY'S TO CITY LIMIT			0	250,000					
			900 SOUTH - 900 WEST TO 300 WEST, WEST TEMPLE TO 900 EAST			0	1,000,000					
			300 WEST - 900 SOUTH TO 2100 SOUTH			0		550,000	550,000			
			900 EAST - HOLLYWOOD TO 2700 SOUTH			0		1,300,000				
			100 SOUTH - NORTH CAMPUS DRIVE TO 900 EAST			0		275,000				
			LOCAL STREETS DISTRICT 3 & 6			0		500,000				
			200 SOUTH - 400 WEST TO 900 EAST			0			125,000	125,000		
			LOCAL STREETS DISTRICTS 2 & 5			0			625,000			
			1100 EAST HIGHLAND , RAMONA TO WARNOCK			0				2,200,000		
			1100 EAST - 900 SOUTH TO RAMONA			0				900,000		
			1700 EAST - 1700 SOUTH TO 2700 SOUTH			0				875,000		
			300 NORTH - 300 WEST TO 1000 WEST			0				250,000		
			LOCAL STREETS DISTRICT 4 & 7			0				500,000		
			VIRGINIA STREET - SOUTH TEMPLE TO 11TH AVE			0					1,700,000	
			1300 EAST - 2100 SOUTH TO 3000 SOUTH			0					550,000	
			W TEMPLE - NORTH TEMPLE TO 400 SOUTH			0					250,000	
			LOCAL STREETS 3 & 6			0					500,000	
			2100 SOUTH - 700 EAST TO 1700 EAST			0						2,000,000
			LOCAL STREETS DISTRICT 1, 4 & 5			0						500,000
		Bond Alternativ	GLADIOLA STREET - 900 SOUTH TO CALIFORNIA			0						
		Bond Alternativ	300 WEST - 400 SOUTH TO 900 SOUTH			0						
		Bond Alternativ	WAKARA WAY - FOOTHILL DRIVE TO CHIPETA WAY			0						
						$ 1,520,406	$ 8,600,000	$ 3,625,000	$ 3,050,000	$ 5,800,000	$ 3,200,000	$ 2,500,000
			PUBLIC UTILITY DEFINED PROJECTS									
	534701008	2016-1200	CLEAN OUT REHABILITATION 2018/19	4	5	75,000	100,000	100,000	100,000	100,000	100,000	
10301	53470977		NORTHWEST DRAIN - IMPROVE BOOM DEPLOYMENT LOCATION AT BOY SCOUT DRIVE	5	3	15,000						
10301		2016-1270	URBAN WETLAND TREATMENT FACILITY AT FAIRMONT PARK - PRE-DESIGN	3	0	0		20,000				
10301		2016-0854	GREEN INFRASTRUCTURE AT HOOTEN BUILDING -ROOF DRAIN INFILTRATION	2	0	0	10,000	30,000				
10301	53470973	2016-1086	STORM WATER QUALITY - DESIGN FOR MAJOR OUTFALLS	3	0	100,000	100,000	100,000				
10301		2015-0132	WQ - WETLANDS TREATMENT FACILITY AT BOY SCOUT DRIVE	1	0	0						1,000,000
						$ 190,000	$ 210,000	$ 250,000	$ 100,000	$ 100,000	$ 100,000	$ 1,000,000
			RIPARIAN CORRIDOR PROJECTS									
10301	534926		EMIGRATION IMPROVEMENTS @ BONNEVILLE GOLF COURSE R03A,RO3B,RO4,RO5A,R05B	4	4	9,459						
10301	53473027	2015-0138	WQ - ROTARY PARK RCO IMPROVEMENTS AND WATER QUALITY FEATURE	4	3	0		250,000				
	STW-1		LEM_R02B , LOWER HOGLE ZOO	3	4	0		25,000	300,000			
10301	534922	2015-0581	LRB_L05A: VA MEDICAL CENTER – BELOW FOOTHILL DRIVE	2	4	0						121,000
10301	534912	2015-0560	UCC_R11C: GUARD SHACK GATE AREA	2	4	0						195,000
10301	534920	2015-0556	UCC_R11A: ELBOW TURN	2	4	0						80,000
10301	534910	2015-0559	LCC_R01B: UPPER FREEDOM TRAIL AREA	2	4	0						164,500
10301	534911	2015-0557	LCC_R01C: LOWER FREEDOM TRAIL AREA	2	4	0						150,000
10301	534918	2015-0578	LCC_R01D02A: UPPER MEMORY GROVE PARK	2	4	0						180,000
10301	534919	2015-0579	LRB_R03: UNIVERSITY – ABOVE CHIPETA WAY	2	4	0						85,000
10301	534923	2015-0582	LRB_R02: UNIVERSITY – BELOW RED BUTTE GARDEN	2	4	0						85,000
10301		2015-0580	UEM_R17: ABOVE DEBRIS BASIN (ROTARY PARK)	2	4	0						10,000
10301		2015-0577	LPC_R05C: MIDDLE SUGARHOUSE PARK	2	4	0						250,000

STORMWATER CIP BUDGET
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COST CENTER	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	CRITICALITY RATING	CONDITION RATING	PAST YEAR 2018-19 (Calc'd from P6)	BUDGET YEAR 2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
10301		2015-0576	LPC_R05B: SUGARHOUSE PARK – HEAR HIGHLAND HIGH TRACK	2	4	0						130,000
10301		2015-0575	LPC_R05A: UPPER SUGARHOUSE PARK	2	4	0						160,000
10301		2016-1201	1700 SOUTH STORM WATER TREATMENT FACILITY	3	0	0			250,000			250,000
10301	53471050	2015-0141	WQ - 10TH NORTH LIFT STATION WATER QUALITY IMPROVEMENTS	5	0	88,652	1,700,000					
10301		2015-0136	LRB_R05C; SUNNYSIDE PARK	1	1	0						173,000
10301		2015-0610	RED BUTTE AT 1300 EAST - RIPARIAN ENHANCEMENTS	2	0	0						10,000
10301	534928	2015-0721	RIPARIAN CORRIDOR SIGNS	2	0	0						50,000
10301		2015-0466	LEM_R03A: BONNEVILLE GOLF COURSE - UPPER	3	3	0						127,000
10301		2015-0467	LEM_R04: BONNEVILLE GOLF COURSE - BELOW STORM DRAIN OUTLET GULLY	3	3	0						200,000
10301		2015-0558	LEM_R01: ROTARY GLEN PARK	2	4	0						16,000
10301		2017-2085	CORNELL LIFT STATION WATER QUALITY IMPROVEMENTS - CONSTRUCTION	2	0	0						700,000
						$ 98,111	$ 1,700,000	$ 275,000	$ 550,000	$ -	$ -	$ 3,136,500
			LOCAL AREA PROJECTS (* WORK BY CITY CREWS)									
10301	534701007	2015-0437	VARIOUS PROJECTS	5	5	100,000	100,000	100,000	100,000	200,000	200,000	
10301	534701006	2015-0439	AVENUE CROSSWALKS / SID VARIOUS STREETS -DIP STONE REPLACEMENT	3	4	50,000	50,000	50,000	50,000	50,000	50,000	
10301	534701005	2015-0440	AVENUE CROSSWALKS AND ADA RAMPS	3	0	50,000	50,000	50,000	50,000	50,000	50,000	
10301	534701004	2015-0438	CONTRIBUTIONS BY DEVELOPERS	3	0	400,000	400,000	400,000	400,000	400,000	400,000	
	53475005		STORM DRAIN BOX DECK REPLACEMENT 2017/2018			79,385						
						$ 679,385	$ 600,000	$ 600,000	$ 600,000	$ 700,000	$ 700,000	$ -
			MASTER PLAN PROJECTS									
		2016-0776	MP35 CULVERT UPGRADES	3	5	0						190,400
		2016-0979	NORTH JOHN GLENN NEW 48 " LINE	4	4	0						3,480,000
		2016-1195	BECK STREET TRUCK REPLACEMENT FROM 200 SOUTH AND 300 WEST TO STATE STREET AND 500 SOUTH	4	3	0						5,449,951
		2016-0758	MP2 FOOTHILL CULVERT - EMIGRATION CREEK AT 2100 EAST	3	3	0						3,000
		2016-0800	MP66 PIPE UPSIZE	3	3	0						16,200
		2016-0788	MP51 EMIGRATION CREEK CHANNEL	3	3	0						22,000
		2016-0789	MP52 NEW 1700 EAST STORM DRAIN	3	3	0						31,000
		2016-0796	MP60 NEW PIPE AND OUTFALL	3	3	0						32,300
		2016-0770	MP21 200 GATSBY POWER PLANT	3	3	0						42,000
		2016-0759	MP3 SUGARHOUSE PARK TELEMETRY	3	3	0						50,000
		2016-0760	MP6 1700 S DETENTION BASIN TELEMETRY	3	3	0						50,000
		2016-0797	MP62 WYOMING STORM DRAIN	3	3	0						51,000
		2016-0805	MP75 PIPE UPSIZE	3	3	0						57,900
		2016-0798	MP63 PIPE UPSIZE	3	3	0						63,200
		2016-0809	MP82 400 SOUTH UPSIZE	3	3	0						63,800
		2016-0801	MP67 PIPE CAPACITY UPGRADES	3	3	0						85,800
		2016-0811	MP84 PIPE UPSIZE	3	3	0						94,200
		2016-0795	MP59 I-80/I-215 DETENTION BASIN	3	3	0						95,000
		2016-0814	MP88 NEW STORM DRAIN COLLECTOR	3	3	0						112,488
		2016-0799	MP64 PIPE UPSIZE	3	3	0						131,700
		2016-0807	MP78 PIPE UPSIZE	3	3	0						170,000
		2016-0784	MP46 SOUTH TEMPLE/FOLSOM AVENUE STREET RECONSTRUCTION	3	3	0						178,000
		2016-0802	MP69 PIPE UPSIZE	3	3	0						198,200
		2016-0806	MP76 NEW STORM DRAIN COLLECTOR	3	3	0						219,785
		2016-0787	MP50 9TH AVENUE STORM DRAIN	3	3	0						267,000
		2016-0808	MP79 WASATCH DRIVE IMPROVEMENTS	3	3	0						173,000

STORMWATER CIP BUDGET
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COST CENTER	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	CRITICALITY RATING	CONDITION RATING	PAST YEAR 2018-19 (Calc'd from P6)	BUDGET YEAR 2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
		2016-0780	MP39 NEW DETENTION BASIN	3	3	0						225,100
		2016-0815	MP89 NEW STORM DRAIN COLLECTOR	3	3	0						243,348
		2016-0782	MP42 REDWOOD ROAD AND CWA NO. 4	3	3	0						321,100
		2016-0777	MP36 LEE DRAIN IMPROVEMENTS	3	3	0						333,200
		2016-0771	MP24 200 EAST IMPROVEMENTS	3	3	0						333,548
		2016-0812	MP85 PIPE UPSIZE	3	3	0						360,300
		2016-0761	MP7 400 SOUTH PUMP STATION	3	3	0						378,500
		2016-0804	MP74 PIPE UPSIZE	3	3	0						387,000
		2016-0765	MP15 LIBERTY PARK DETENTION BASIN	3	3	0						391,899
		2016-0793	MP57 BRIGHTON DRAIN CHANNEL IMPROVEMENTS	3	3	0						452,200
		2016-0769	MP20 DETENTION BASIN - 800 SOUTH 4050 WEST	3	3	0						455,000
		2016-0810	MP83 LAURELHURST DRIVE IMPROVEMENTS	3	3	0						501,000
		2016-0773	MP28 I STREET CONDUIT	3	3	0						502,986
		2016-0772	MP27 BRIGHTON DRAIN CHANNEL IMPROVEMENTS	3	3	0						561,400
		2016-0778	MP37 NEW CHANNEL AND DETENTION BASIN	3	3	0						609,000
		2016-0786	MP49 500 SOUTH IMPROVEMENTS	3	3	0						635,592
		2016-0767	MP17 DETENTION BASIN AND CHANNEL	3	3	0						714,000
		2016-0766	MP16 CHANNEL TO I-80 INTERCHANGE	3	3	0						718,200
		2016-0791	MP54 CWA NO. 4 (1400 WEST) AT 200 SOUTH	3	3	0						728,900
		2016-0794	MP58 LEE DRAIN IMPROVEMENTS	3	3	0						729,400
		2016-0790	MP53 FOOTHILL DRIVE STORM DRAIN	3	3	0						774,000
		2016-0779	MP38 LEE DRAIN IMPROVEMENTS	3	3	0						778,600
		2016-0762	MP11 DETENTION BASIN OVERFLOW	3	3	0						807,300
		2016-0803	MP71 INTERSECTION CROSS DRAIN UPGRADES	3	3	0						1,065,000
		2016-0781	MP40 EAST BENCH AND FEDERAL HEIGHTS IMPROVEMENTS	3	3	0						1,152,532
		2016-0813	MP87 CWA NO. 1 IMPROVEMENTS	3	3	0						1,287,200
		2016-0764	MP13 EMIGRATION CONDUIT	3	3	0						1,308,000
		2016-0768	MP18 UNDERSIZED CULVERTS, CHANNEL IMPROVEMENTS, DETENTION BASIN	3	3	0						1,352,600
		2016-0785	MP47 PIPELINE FROM BECK STREET	3	3	0						1,693,643
		2016-0783	MP44 CWA NO. 2 AT I-80 NORTH TEMPLE OFF RAMP/AIRPORT DETENTION BASIN	3	3	0						2,031,000
		2016-0774	MP29 VARIOUS IMPROVEMENTS	3	3	0						2,114,200
		2016-0775	MP32 600 EAST CONDUIT	3	3	0						2,540,522
		2016-0763	MP12 900 SOUTH CONDUIT	3	3	0						12,626,142
		2016-0757	MP1 UPPER DRY CREEK DETENTION BASIN	3	0	0						616,000
						$ -	$ -	$ -	$ -	$ -	$ -	$51,056,336
			TOTAL COLLECTION LINES			$ 3,498,941	$12,530,000	$6,880,000	$4,321,000	$6,973,000	$4,300,000	$77,549,636
	2730.20		**LANDSCAPING**									
10301	53470934		NORTHWEST OIL DRAIN			0	150,000					
						$ -	$ 150,000	$ -	$ -	$ -	$ -	$ -
			TOTAL CAPITAL IMPROVEMENTS			$ 3,783,053	$12,744,000	$7,630,000	$4,371,000	$7,023,000	$4,300,000	$78,215,136

STORMWATER UTILITY CAPITAL PURCHASES BUDGET
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COST CENTER	OBJECT CODE	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	Comments	CRITICALITY RATING	CONDITION RATING	PAST YEAR 2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
53-10201	2710.10			LAND										
								$ -	$ -	$ -	$ -	$ -		$ -
								0	0	0	0			0
	2750.10			MOTIVE REPLACEMENT AUTO & TRUCK										
				VARIOUS						400,000	400,000	400,000	400,000	
5310701	2750.10			3/4 TON TRUCK EXTENDED CAB WITH CABIN CHASSIS 4X4										
5310201	2750.10			3/4 TON TRUCK 4X4										
5310701	2750.10			3/4 TON W/UTILITY BED 4X4										
5310701	2750.10			3/4 TON W/UTILITY BED 4X4`				28,961						
5310201	2750.10		36840	FORD 1 TON CAB-N-CHASSIS WITH DUMP BED				28,961						
5310201	2750.10		36900	GMC 3/4 TON 4WD PICK-UP				34,498						
5310201	2750.10		33520	ESCAPE SUV				23,500						
5310201	2750.10			CLUB CAR CARRY ALL 500 (4)				52,632						
5310201	2750.10			10 WHEEL DUMP TRUCK										
5310301	2750.10			CHEV OR SIMILAR MID-SIZED 4X4 PICK UP W/BED COVER	Jason				30,000					
5310201	2750.10		36010	Replace Mack GU713	Randy				455,149					
5310201	2750.10		36080	Replace Ford F250 W/Dump Bed	Randy				41,500					
5310201	2750.10		36150	Replace Mack Granite	Randy				146,000					
								$ 168,552	$ 672,649	$ 400,000	$ 400,000	$ 400,000	$ 400,000	$ -
	2750.30			FIELD MAINTENANCE EQUIPMENT										
				VARIOUS						180,000	180,000	180,000	180,000	
5310201				VACTOR TRUCK				200,000						
5310201				75618000 6"-18" IPS BUTT FUSION MACHINE GAS HIGH FRC CYL (lincludes insert)				52,068						
5310201				CM-958H SED CEMENT MIXER 9 CF HONDA ENGINE				5,597						
5310201				SAND MASTER (SAND BAGGER)				12,241						
5310201				LOAD KING TRAILER 55 TON				69,260						
				CATERPILLAR 420F2 BACKHOE										
				SELF PROPELLED PIPE FUSION MACHINE										
5310201				BACKHOE BUYBACK PROGRAM				9,000						
5310201				TRACK EXCAVATOR W/DOZER BLADE (REPLACE 36870)										
5310201			NEW	LINKBILT AMI 54" ROOT RAKE	Randy				7,000					
5310201			NEW	HAULING PIPE	Randy				8,500					
								$ 348,166	$ 15,500	$ 180,000	$ 180,000	$ 180,000	$ 180,000	$ -
	2760.30			TELEMETERING										
5310201				RADIO REPLACEMENT				40,086						
5310201				VARIOUS				5,000	40,000	40,000	40,000	40,000	40,000	
								$ 45,086	$ 40,000	$ 40,000	$ 40,000	$ 40,000	$ 40,000	$ -
	2760.50			OFFICE EQUIPMENT										
								$ -	$ -	$ -	$ -	$ -		$ -
	2760.90			OTHER EQUIPMENT										
5310201				ENCLOSED TRAILER										
5310201				DUEL REEL AIR COMPRESSOR										
5310201				2 ECO FRIENDLY PUMPS										
5310201				3 AUTOMATIC COMPOSITE SAMPLERS										
5310201				VARIOUS				5,000						
5310201				CEMENT MIXER										
5310201				JETSCAN VIDEO NOZZLE										
5310201				HERBICIDE SPRAYER PUMP SYSTEM										
5310201				60" ROTARY EXCAVATOR MOWER COMPLETE										
								$ 5,000	$ -	$ -	$ -	$ -	$ -	$ -

STORMWATER UTILITY CAPITAL PURCHASES BUDGET
Five Year Projected Budget FY2020-2024

COST CENTER	OBJECT CODE	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	Comments	CRITICALITY RATING	CONDITION RATING	PAST YEAR 2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
				TOTAL CAPITAL OUTLAY				$ 566,804	$ 728,149	$ 620,000	$ 620,000	$ 620,000	$ 620,000	$ -

Street Lighting Utility- Budget Summary and Cash Flow

STREET LIGHTING UTILITY
ENTERPRISE FUND
BUDGET SUMMARY
FY 2020-2022

SOURCES	ACTUAL 2017-18	AMENDED BUDGET 2018-19	PROJECTED ACTUAL 2018-19	PROPOSED BUDGET 2019-20	FORECAST BUDGET 2020-21	FORECAST BUDGET 2021-22
REVENUES						
STREET LIGHTING FEES	$ 4,198,227	$ 4,170,000	$ 4,198,227	**$ 4,198,227**	$ 4,198,227	$ 4,198,227
INTEREST INCOME	94,979	52,000	52,000	**30,000**	29,000	29,000
OTHER REVENUES	2,991	9,000	11,000	**9,000**	9,000	9,000
TOTAL REVENUES	$ 4,296,197	$ 4,231,000	$ 4,261,227	**$ 4,237,227**	$ 4,236,227	$ 4,236,227
OTHER SOURCES						
GRANTS & OTHER RELATED REVENUES	195,808	-	-	**-**	-	-
TRANSFERS FROM GENERAL FUND	20,000	20,000	20,000	**20,000**	20,000	20,000
IMPACT FEES	-	-	-	**-**	-	-
BOND PROCEEDS	-	-	-	**-**	-	-
T O T A L OTHER SOURCES	215,808	20,000	20,000	**20,000**	20,000	20,000
T O T A L SOURCES	$ 4,512,005	$ 4,251,000	$ 4,281,227	**$ 4,257,227**	$ 4,256,227	$ 4,256,227
EXPENSES & OTHER USES						
EXPENDITURES						
PERSONNEL SERVICES	$ 206,367	$ 198,307	$ 198,307	**$ 281,575**	$ 292,836	$ 304,548
OPERATING & MAINTENANCE	462	7,300	7,300	**7,300**	7,446	7,596
TRAVEL & TRAINING	1,368	3,000	3,000	**3,000**	3,060	3,121
UTILITIES	850,841	990,900	990,900	**1,010,900**	970,422	937,223
TECHNICAL SERVICES	1,035,264	1,720,028	1,720,028	**1,638,204**	1,523,964	1,503,287
DATA PROCESSING	1,117	-	-	**-**	-	-
FLEET MAINTENANCE	-	-	-	**-**	-	-
ADMINISTRATIVE SERVICE FEE	32,450	20,000	20,000	**20,000**	20,400	20,808
PAYMENT IN LIEU OF TAXES	-	-	-	**-**	-	-
RISK MANAGEMENT	-	-	-	**-**	-	-
TRANSFERS TO GENERAL FUND	-	-	-	**-**	-	-
OTHER CHARGES AND SERVICES	14,017	2,406	2,406	**2,298**	2,613	2,665
TOTAL EXPENDITURES	2,141,886	2,941,941	2,941,941	**2,963,277**	2,820,741	2,779,248
OTHER USES						
CAPITAL OUTLAY	-	-	-	**-**	-	-
CAPITAL IMPROVEMENT BUDGET	1,898,666	2,621,414	2,605,000	**1,725,000**	2,360,000	2,025,000
DEBT SERVICES	105,927	103,000	103,000	**103,000**	191,000	190,000
T O T A L OTHER USES	$ 2,004,593	$ 2,724,414	$ 2,708,000	**$ 1,828,000**	$ 2,551,000	$ 2,215,000
T O T A L USES	$ 4,146,479	$ 5,666,355	$ 5,649,941	**$ 4,791,277**	$ 5,371,741	$ 4,994,248
EXCESS REVENUE AND OTHER SOURCES OVER (UNDER) USES	$ 365,526	$ (1,415,355)	$ (1,368,714)	**$ (534,050)**	$ (1,115,514)	$ (738,021)
OPERATING CASH BALANCES						
BEGINNING JULY 1	$ 5,472,718	$ 5,838,244	$ 5,838,244	**$ 4,469,530**	$ 3,935,480	$ 2,819,966
ENDING JUNE 30	$ 5,838,244	$ 4,422,889	$ 4,469,530	**$ 3,935,480**	$ 2,819,966	$ 2,081,945
Cash Reserve Ratio	273%	150%	152%	132.8%	100.0%	74.9%

Cash reserve goal above 10%

STREET LIGHTING UTILITY
CASH FLOW
FY 2020 BUDGET
AND FY 2021-2024 FORECAST

	Actual YEAR 2017-2018	Projected YEAR 2018-2019	BUDGET YEAR 2019-2020	BUDGET YEAR 2020-2021	BUDGET YEAR 2021-2022	BUDGET YEAR 2022-2023	BUDGET YEAR 2023-2024
STREET LIGHTING SALES	4,198,227	4,198,227	4,198,227	4,198,227	4,198,227	4,198,227	4,198,227
OTHER INCOME	2,991	11,000	9,000	9,000	9,000	9,000	9,000
INTEREST INCOME	94,979	52,000	30,000	29,000	29,000	29,000	29,000
OPERATING INCOME	4,296,197	4,261,227	4,237,227	4,236,227	4,236,227	4,236,227	4,236,227
OPERATING EXPENSES	(2,141,886)	(2,941,941)	(2,963,277)	(2,820,741)	(2,779,248)	(2,840,922)	(2,904,074)
NET INCOME EXCLUDING DEP.	2,154,311	1,319,286	1,273,950	1,415,486	1,456,979	1,395,305	1,332,153
BOND PROCEEDS	-	-	-	-	-	-	-
OTHER CONTRIBUTIONS	215,808	20,000	20,000	20,000	20,000	20,000	20,000
CAPITAL OUTLAY	-	-	-	-	-	-	-
DEBT SERVICE	(105,927)	(103,000)	(103,000)	(191,000)	(190,000)	(190,000)	(190,000)
OTHER INCOME & EXPENSE	109,881	(83,000)	(83,000)	(171,000)	(170,000)	(170,000)	(170,000)
GENERATED FOR CAPITAL	2,264,192	1,236,286	1,190,950	1,244,486	1,286,979	1,225,305	1,162,153
CAPITAL IMPROVEMENTS	(1,898,666)	(2,605,000)	(1,725,000)	(2,360,000)	(2,025,000)	(2,025,000)	(1,525,000)
BEGINING CASH BALANCE	5,472,718	5,838,244	4,469,530	3,935,480	2,819,966	2,081,945	1,282,250
CASH INCREASE/(DECREASE)	365,526	(1,368,714)	(534,050)	(1,115,514)	(738,021)	(799,695)	(362,847)
ENDING BALANCE	5,838,244	4,469,530	3,935,480	2,819,966	2,081,945	1,282,250	919,403
RATE CHANGE	0%	0%	0%	0%	0%	0%	0%
Cash Reserve Ratio	272.6%	151.9%	132.8%	100.0%	74.9%	45.1%	31.7%
Debt Service Coverage	20.34	12.81	12.37	7.41	7.67	7.34	7.01
DEBT SERVICE % OF GROSS OP. REV.	2.5%	2.4%	2.4%	4.5%	4.5%	4.5%	4.5%
RESIDENTIAL BILL OF 1 ERU (or 75 ft)	3.73	3.73	3.73	3.73	3.73	3.73	3.73

STREET LIGHTING UTILITY
CIP BUDGET
Five Year Projected Budget 2020-2024

COST CENTER	PROJECT NUMBER	PROJECT DESCRIPTION	CRITICALITY RATING	CONDITION RATING	PAST YEAR SPENT 2018-19	BUDGET YEAR 2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
48-48001	2730.80	**Base Level Projects**									
48001	48135	ARTERIAL & COLLECTOR STREET HE AND SYSTEM UPGRADES	2	4	300,000	300,000	300,000	300,000	300,000		
48001	48126	HIGH WATTAGE REPLACEMENTS				500,000	500,000	500,000	500,000	500,000	2,500,000
48001	48130	NEIGHBORHOOD HE AND SYSTEM UPGRADES	4	4	1,000,000	500,000	500,000	500,000	500,000	500,000	2,500,000
48001	48137	1300 EAST - STREET LIGHTS	3	3							
48001		LOCAL STREET IMPROVEMENT SUPPORT			50,000	200,000	200,000	200,000	200,000	200,000	1,000,000
		LIGHTING CONTROLS				200,000	500,000	500,000	500,000	300,000	
		BASE LEVEL - TOTAL IMPROVEMENTS			$ 1,350,000	$ 1,700,000	$ 2,000,000	$ 2,000,000	$ 2,000,000	$ 1,500,000	$ 6,000,000
48-48101	2730.80	**TIER 1 Projects**									
48101	48131	Tier 1 Capital Replacements			5,000	5,000	5,000	5,000	5,000	5,000	595,000
48101		Tier 1 HE Upgrades					190,000				210,000
		TIER 1 - TOTAL IMPROVEMENTS			$ 5,000	$ 5,000	$ 195,000	$ 5,000	$ 5,000	$ 5,000	$ 805,000
48-48201	2730.80	**TIER 2 Projects**									
48201	48132	Tier 2 Bad Wiring Replacement			365,000						
48201	48139	Tier 2 Capital Replacement			5,000	5,000	5,000	5,000	5,000	5,000	395,000
48201	48133	Tier 2 HE Upgrades			100,000						
		TIER 2 - TOTAL IMPROVEMENTS			$ 470,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 395,000
48-48301	2730.80	**TIER 3 Projects**									
48301	48140	Tier 3 Capital Replacement			15,000	15,000	15,000	15,000	15,000	15,000	2,310,000
48301	48134	Tier 3 HE Upgrades			765,000		145,000				160,000
		TIER 3 - TOTAL IMPROVEMENTS			$ 780,000	$ 15,000	$ 160,000	$ 15,000	$ 15,000	$ 15,000	$ 2,470,000
		TOTAL CAPITAL IMPROVEMENTS			$ 2,605,000	$ 1,725,000	$ 2,360,000	$ 2,025,000	$ 2,025,000	$ 1,525,000	$ 9,670,000

APPENDIX A: Proposed Rate Structure and WRF Resolutions

APPENDIX B: Rationale for New Positions

Proposed New Public Utilities Positions and Organizational Changes for FY 2020 (in alphabetical order)

Community and Engagement (one FTE and Organization Change)

The Department has identified a need for one full time employee to assist with public engagement. This position, Community and Engagement Coordinator, would report to the Community and Engagement Manager, and support all print and television media needs, website, and social media functions. The position would also assist with community feedback and education on the Department's numerous programs, planning efforts, and capital improvement projects. Engagement related to planning and programmatic work includes watershed, water conservation, street lighting, and stormwater master planning. In addition, construction related to large capital projects, such as those related to the new WRF, the East-West Conveyance, and streets bond-related projects will have an impact on the community and require additional engagement.

The Department is proposing to move the Employee Development and Training Coordinator position to report to the Community and Engagement Manager. The Employee Development and Training Coordinator position currently reports to the Department Director.

The Department is proposing to reclassify the Community and Engagement Manager to a slightly higher pay classification to reflect additional management responsibility.

Development Services (one FTE)

The Department has identified the need for a dedicated records technician in the Department's Development Services division. This is due to increased growth throughout the Department's service area, including within Salt Lake City, Cottonwood Heights, Mill Creek, and Holladay. This position will report to the Water Rights, Contracts, and Property Manager, and be responsible for maintaining and updating electronic files, including agreements, plans, general correspondence, and general administration files. This position will also assist with succession planning due to anticipated retirements in this area.

Engineering (five FTEs)

See attached memorandum dated March 20, 2019 from Jason Brown, Chief Engineer to Laura Briefer, Director of Public Utilities.

GIS Leak Detection (one FTE)

The Department has identified a need to add one FTE to support the Department's leak detection program. Currently there is only one position allocated to this task, and therefore no redundancy in this function. The leak detection function allows the Department to identify water loss caused by leaks in the water distribution system. Leaks in the system lead to water waste and lost revenue.

Maintenance and Operations (one FTE)

The Department has identified the need for an additional Senior Water System Maintenance Worker. This position was approved in the Department's FY2019 budget.

However, the Department reclassified this position as a Maintenance Electrician IV in order to address a safety need for our emergency water crews. The Department is in a several year process of converting more than 90,000 water meters in to smart meters across the water service area. The Senior Water System Maintenance Worker is needed specifically to change large meters for industry, business, and institutional properties. This position also supports succession planning in the Maintenance and Operations Division. This employee will report to the Water System Maintenance Supervisors who will report to the Water Distribution System Manager.

Special Projects Manager Reclassification and Water Resources Reorganization

The Department is proposing to reclassify the Special Projects Manager position to a Water Resources Manager position and create a Water Resources Division. The Water Resources Division will be responsible for administering the City's water rights, maintaining water supply and demand data, climate and energy initiatives, and water conservation programs. The Water Resources Manager will report to the Department Director, and oversee the Sustainability, Water Conservation, and Hydrology functions. The purpose of this change is to increase capacity to better address and coordinate recommended actions identified in the Department's updated Water Supply and Demand Plan, Drought Contingency Plan, and Water Conservation Plan. In addition, the state has increased reporting requirements related to water rights, water source sizing, and water loss, which this position and division will manage. Finally, this reorganization facilitates succession planning.

Sustainability (one FTE)

The Department has identified a need for one full time employee to assist with energy management, energy and greenhouse gas reduction, and climate change projects. This position will report to the Water Resources Manager. This Sustainability Manager position is needed to ensure compliance with City energy initiatives and assist the Department with its climate change vulnerability assessments, mitigation, and adaptation planning. This includes the following:

- **The Comprehensive Energy Management Executive Order**: This City Executive Order requires that the Department prepare and implement energy management plans, and places requirements on renovation and new construction of the Department's facilities: http://www.slcinfobase.com/PPAREO/#!WordDocuments/comprehensiveenergymanagementofsaltlakecityfacilities.htm.
- **The Elevate Buildings Commercial Ordinance (Section 18.94.050)**: This City ordinance requires that the Department prepare and submit energy benchmarking information to the Sustainability Department and to the public: http://sterlingcodifiers.com/codebook/index.php?book_id=672&chapter_id=102505
- **Salt Lake City Department of Public Utilities Renewable Energy Plan (2015):** This plan identifies opportunities throughout the Department's infrastructure for the generation of renewable energy.
- **Salt Lake City Department of Public Utilities Wire to Water Efficiency Study (2018)**: This study identifies capital and operational actions that the Department can take to reduce energy use. *The Department has estimated that implementation*

of energy efficiency strategies identified in this study will result in a potential annual cost savings of $200,000, and 4,000,000 kilowatt hours.

- **Salt Lake City Department of Public Utilities Climate Change Vulnerability Assessment and Adaptation Plan (ongoing)**: The Department is in its second year of a five-year scientific study with the University of Utah to identify climate risks related to water supply, water quality, and storm intensification. The study will result in an adaptation plan to mitigate identified climate risks.

Wastewater Pretreatment Program (four FTEs)

The Department's Pretreatment Program is required by Section 403 of the Clean Water Act. The overall mission of the Pretreat Program is to provide protection to the Publicly Owned Treatment Works (POTW), protect the health and safety of collections and treatment staff and the environment from hazardous, toxic, and incompatible pollutant discharge into the sanitary sewer system and also promote the health and safety of the general public by minimizing the potential for sanitary sewer overflow events.

Four additional staff positions are requested for the Pretreatment Program:

- Fats, Oil, and Grease (FOG)/Sewer Rate Program Supervisor
- Pretreatment Inspector/Permit Writer
- Senior Wastewater Sampler/Inspector
- Administrative Assistant (WRF)

These positions are needed for the program to meet the demands of current city growth as well as planned industrial growth in the Northwest Quadrant. New federal wastewater discharge prohibitions have created additional work. Two recent regulatory examples relate to hazardous waste pharmaceuticals and dental amalgam. When compared to programs in cities of similar population and industrial influence, the Department's Pretreatment Program is understaffed. This shortfall was noted by the Utah Division of Water Quality (UDWQ) during their 2018 inspection. The UDWQ inspection findings report stated: "*With the growth of the permitting load and the dental program it is recommended that the city evaluate the need for additional staffing.*"

The FOG/Sewer Rate Program Supervisor will take a proactive role to reduce FOG loading into the collection system. Currently there are areas of the city the Collections team has to clean quarterly due to FOG buildup in the lines. The discharge of FOG material into the collection system can lead to sewer overflow and more rapid degradation of the collection system. The supervisor will also be tasked with ensuring sewer rates are properly assigned to commercial and industrial used based on pollutant loading.

Watershed Program (two Seasonal Positions)

The Department has identified the need for two seasonal watershed worker positions during the summer. Recreation continues to increase in the City's watersheds in City Creek, Parleys, Big Cottonwood, and Little Cottonwood Canyons. This is resulting in potential impacts to water quality. Seasonal watershed workers help with upkeep of restroom

facilities at popular trailheads, stewardship of the Department's preserved lands, and public education under the Keep it Pure program.

TO:	Laura Briefer, Director of Public Utilities
BY:	Jason Brown, P.E., Chief Engineer
DATE:	March 20, 2019
SUBJECT:	Request for five additional Engineering staff FTE's for fiscal year 2020

Background, Purpose and Need

The objective of this memorandum is to provide justification and recommendation for additional staff for the Engineering Division within Public Utilities.

The Engineering Division of the Department of Public Utilities has been going through dramatic changes in terms of updating our practices, organization, project elements, and work responsibilities to enhance our services for better accountability, performance, transparency, and efficiency in the delivery of engineering services to the Utility and the public. These changes coupled with changes in the industry have highlighted resource needs and workload stresses in our work environment that impede our ability and capacity for continued successful project delivery.

Summary

We present the following justifications for increasing the in-house staff FTE's for the Engineering group:

(1) The current and past CIP workload justifies more in-house staff.

In 1994 Hughes, Heiss & Associates conducted an audit of the Engineering group. They recommended increasing the staff based on the CIP program funding at that time and concluded that using Consultants to fill in the production gap was not "cost effective". At the time, a reorganization of Engineering was done but no additional staff was added.

The total CIP program for water/sewer/drainage in 1994 when the audit was conducted was under $10M. Currently it is over $170M and the number of FTE's has remained basically the same (Figure 1 & Figure 2). The demands on the current staff are increasing as public outreach, engagement and education are drawing away time that was typically allocated for design and construction. Many of these critical activities we have been able to temper with advances in efficiencies using technologies but even with advances with technology, the technology requires staff time.

(2) In-house staff is less expensive than using Consultants for the CIP workload.

The average cost of the existing Engineering staff including overhead (7.72%) and labor additive (56.36%) is $51.68 per hour. The average hourly cost which will be charged by Consultants for project engineers based on the most recent General Services SOQ's is approximately $150 per hour. Doing work with City staff is approximately a <u>third</u> of the cost of using a Consultant. With new staff positions being limited, we have utilized outside consultants for much of the additional inspection and design. This method allows staff to manage approximately 2 to 4 times the number of projects depending on complexity. However, the costs to design and inspect the projects are generally 3 times more expensive because of reasons stated above.

(3) Aging infrastructure requires additional staff to maintain cost effectiveness.

The CIP budget levels is projected to increase, particularly with the Water Reclamation Plant where a process upgrade project will be required to meet permit requirements for nutrient removal. The Nutrient project is projected to be $528 million over the next 7 years. The other programs (water/sewer/drainage/lighting) are also showing increased budget funding requirements due to aging infrastructure and regulatory requirements. Assuming 10% design/construction management cost and 30% vacation/sick/holiday discount, this CIP program will require 36 FTE's. The current staff level is 27.72 FTE's. The gap is currently being supplemented through consultant contracts, but as additional condition assessments have been completed, we are finding that the breadth of improvements necessary to maintain a high level of service to the community is expanding.

(4) To reduce inspector overtime.
The overtime cost for inspectors in 2018 was $137k. Converting this cost to full time FTE's equates to 1.5 additional inspector FTE.

<u>RECOMMENDATION</u>

We are requesting the addition 5 of FTE's to the Engineering group based on the analysis discuss above. Specifically, we are recommending the following changes to the staffing document as outlined below.

<u>New Staff Positions</u>

+3 E Tech II	E Tech II to support development in the Department service area, including Salt Lake County and the Northwest Quadrant.
Justification	Based on current workload needs to assist in the inspection and drafting. Roughly 1/3 the cost will be to have in-house inspection rather than consultant contracted inspection. This can become a cost savings for the Department. Having internal staff inspect infrastructure has the added benefit of knowledge retention within the department rather than the external consultant. In addition, many of the existing inspection staff are approaching retirement age and hiring newer staff is in line with succession planning within the department.
+2 Eng II/II	Project Engineer/Development Review Engineer
Justification	As with the inspectors having internal staff design, manage and review the upcoming CIP projects will benefit the department with reducing the costs associated with having external consultants design, manage and review. The additional staff will also tackle the projected workload, aging infrastructure and regulatory requirements.

Below are two figures illustrating the relative need and impact of the City's robust capital improvement program. These are anecdotal but support the business case and workplan justification described above.

NET CHANGE = +6 FTE by 5 new staff positions and reassignment of one staff position

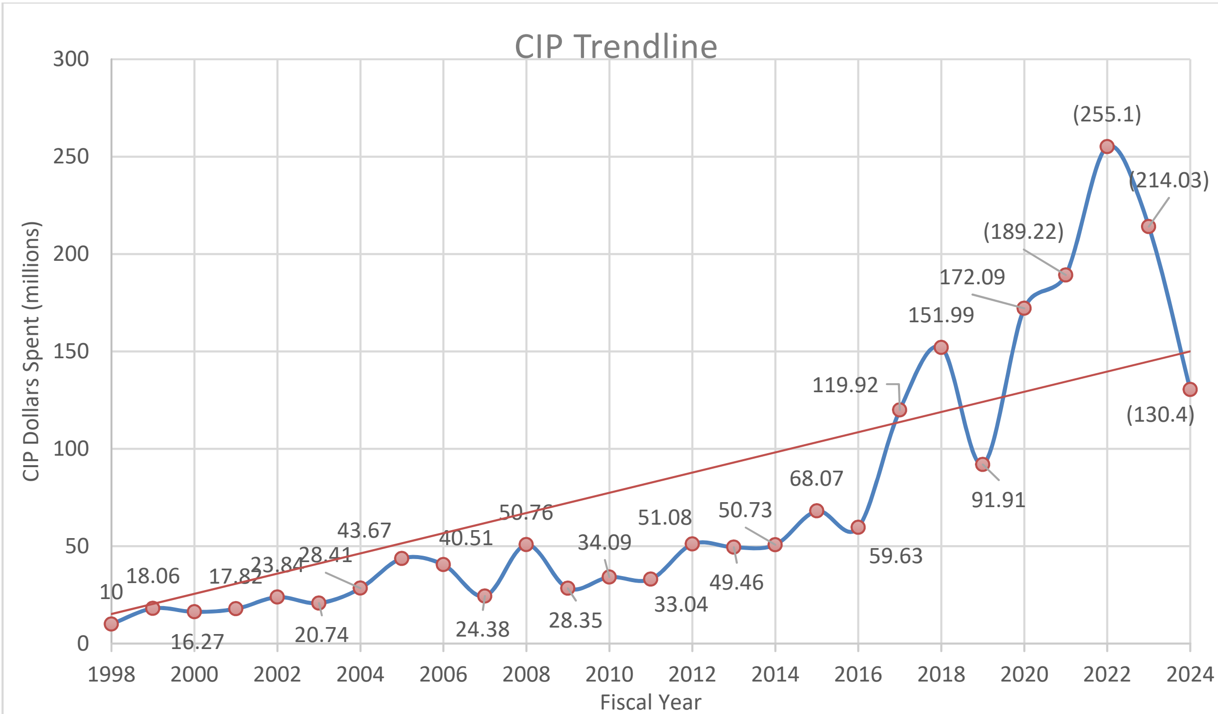


Figure 1 – CIP Trend line

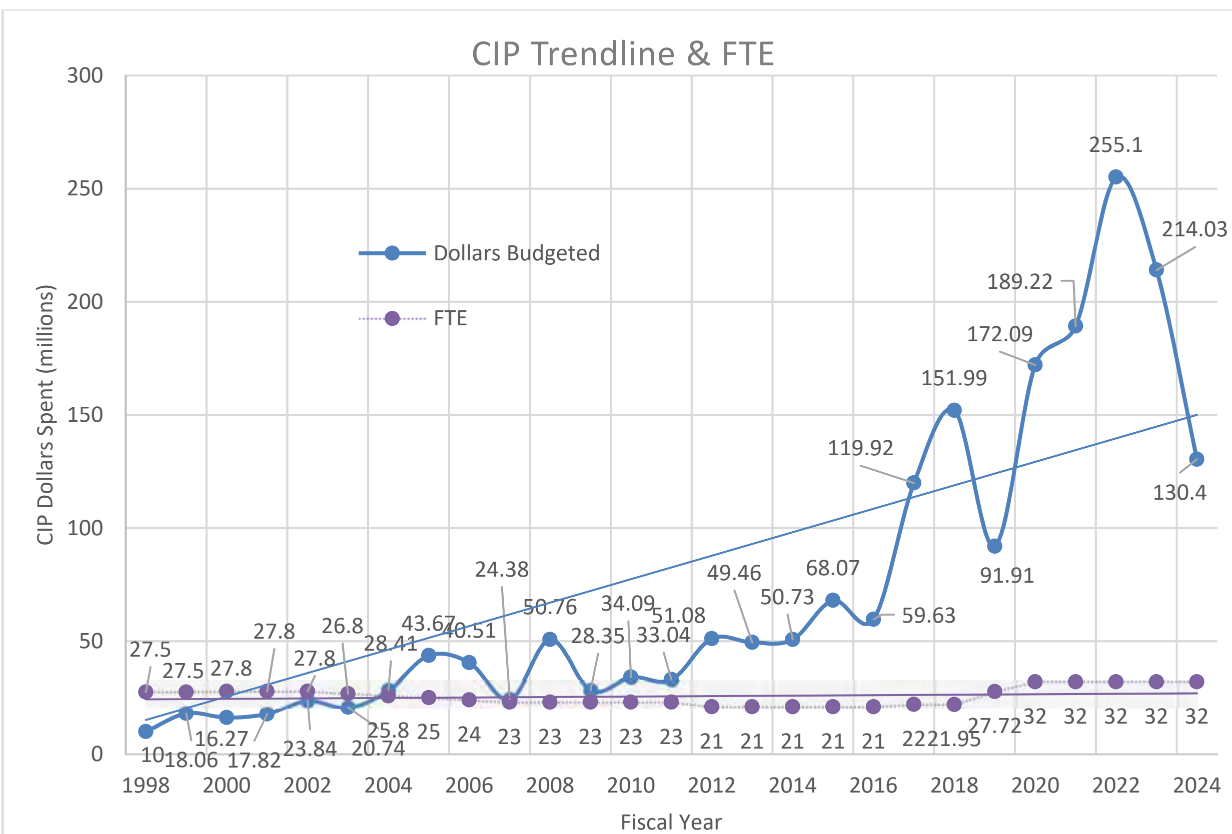


Figure 2 – CIP vs. Engineering group FTE staffing level

APPENDIX C: Public Utilities' Energy Management and Greenhouse Gas Mitigation Projects

Public Utilities Energy Management and Greenhouse Gas Mitigation Projects

Environmental sustainability is at the root of the Department of Public Utilities' legacy and public ethic. Indeed, the Department's mission statement is "serving our community, protecting our environment." The Department has been a steward of water resources serving the Salt Lake Valley for more than a century. Public Utilities later took on the role of protecting public health and the environment through wastewater treatment and stormwater systems and developing street lighting as a self-sustaining utility.

One major component of this legacy is actively addressing the Department's energy use and greenhouse gas emissions, as climate change will have significant implications for Public Utilities' capacity to provide water services to its customers. Mayor Biskupski requested each City Department include as part of its FY2020 budget a demonstrated reduction of greenhouse gas emissions. The Department is providing a summary of efforts identified in the recommended budget that will contribute to this goal.

There are several City policies and goals that drive the Department's efforts regarding energy efficiency, greenhouse gas reduction, and other sustainability practices. These policies include:

- Comprehensive Energy Management of Salt Lake City Facilities Executive Order
- LEED Design Standards Executive Order
- Net-Zero Energy Buildings Executive Order
- Climate Positive 2040
- Elevate Buildings Ordinance

In addition to these governing City policies, the Department has also developed a Public Utilities Energy Policy to guide energy efficiency efforts for all operations and capital projects:

> *SLCDPU uses energy wisely while continuing to exceed the expectations of those we serve. We implement prudent and environmentally responsible strategies and programs in our facilities and operations that minimize our energy use without sacrificing service reliability.*

The FY2020 recommended budget includes funding, both operational and capital, for several efforts that support the Department's Energy Policy and various City goals, ordinances, and Executive Orders. These projects have been identified in the Capital Plans for all enterprise funds. Each identified project has a sustainability component that will contribute to the fulfillment of the various requirements. Examples include:

- A Wire-to-Water Energy Efficiency Study was completed in January 2019 and identified an energy savings potential of 12%. This savings percentage translates to approximately $200,000 and 4,000,000 kWh per year with all capital and operation improvements identified and recommended in the study. Five key projects were identified in the study whose implementation would result in 2,600

metric tons per year of avoided carbon emissions at an initial capital cost of $2,525,000 with a 5.7-year payback period.

  - Select Sources According to Energy Requirements
  - Implement a Leak Detection Program
  - Preserve Pressure from Parley's Water Treatment Plant
  - Install Flow Meters at Pump Stations
  - Optimize the Military Pump Station

- Within the Water Utility, the major upgrade projects at each of the three drinking water treatment plants will consider energy efficiency, reduction of greenhouse gases, and compliance with all executive orders and initiatives. There are also several other Water Utility capital projects that will contribute to the Department's overall sustainability goals, including pump and motor upgrades, the AMI meter replacement program, and designated funding to address specific projects recommended in the Wire-To-Water Energy Efficiency Study. The Parley's Canyon hydropower project design is budgeted for FY 2020, with completion anticipated by 2022. At this time, it is anticipated the project will provide a renewable energy source that is anticipated to generate $126,600 per year in revenue.
- The Sewer Utility also includes several projects in the Capital Plan that will meet sustainability goals, including pump replacements, upgrades to existing reclamation facility, inflow and infiltration studies, and flow meter installation. Most significantly, the design of the new Water Reclamation Facility includes a Sustainability Task Force that is dedicated to the analysis and implementation of energy efficiency/greenhouse gas reduction improvements throughout the occupied buildings and process components of the plant.
- There are several lift station rehabilitation and abandonment projects identified in the Stormwater Capital Plan that will contribute to the achievement of sustainability goals. Rehabilitation projects may entirely replace the pumps and motors or significantly repair these components to reduce overall energy use of the lift station. The abandonment projects will remove a source of energy use altogether, again creating a positive effect on the Stormwater Utility's sustainability impact.
- The goal of the Street Lighting Utility is to have all street lights equipped with energy efficient technology by 2023. The Utility is on track to meet this goal. Data from 2018 indicates that more than 60% of street lights are energy efficient with approximately 3,580,650 kWh in savings since 2014. The high efficiency upgrade projects in the Capital Plan are planned solely to meet the energy efficiency goals for the Street Lighting Utility.

APPENDIX D: Rate Change Comparisons and Customer Impacts

Water Rate Change Comparisons

**Comparison of Monthly Water Base Rate Options
for City Customers**

Meter Size (inches)	2019 Current Rate	2019 Rate Study	2020 Proposed Rate	Changes: Current to Rate Study $	Changes: Current to Rate Study %	Changes: Rate Study to Proposed $	Changes: Rate Study to Proposed %	Changes: Current to Proposed $	Changes: Current to Proposed %
3/4	9.89	8.84	9.28	-1.05	-11%	0.44	5%	-0.61	-6%
1	9.89	11.56	12.14	1.67	17%	0.58	5%	2.25	23%
1 1/2	11.68	18.37	19.29	6.69	57%	0.92	5%	7.61	65%
2	12.68	26.55	27.88	13.87	109%	1.33	5%	15.20	120%
3	21.28	48.34	50.76	27.06	127%	2.42	5%	29.48	139%
4	22.78	72.86	76.50	50.08	220%	3.64	5%	53.72	236%
6	32.89	140.98	148.03	108.09	329%	7.05	5%	115.14	350%
8	59.11	222.71	233.85	163.60	277%	11.14	5%	174.74	296%
10	109.63	576.91	605.76	467.28	426%	28.85	5%	496.13	453%

**Comparison of Monthly Water Base Rate Options
for County Customers**

Meter Size (inches)	2019 Current Rate	2019 Rate Study	2020 Proposed Rate	Changes: Current to Rate Study $	Changes: Current to Rate Study %	Changes: Rate Study to Proposed $	Changes: Rate Study to Proposed %	Changes: Current to Proposed $	Changes: Current to Proposed %
3/4	13.35	11.93	12.53	-1.42	-11%	0.59	5%	-0.82	-6%
1	13.35	15.61	16.39	2.25	17%	0.78	5%	3.04	23%
1 1/2	15.77	24.80	26.04	9.03	57%	1.24	5%	10.27	65%
2	17.12	35.84	37.64	18.72	109%	1.80	5%	20.52	120%
3	28.73	65.26	68.53	36.53	127%	3.27	5%	39.80	139%
4	30.75	98.36	103.28	67.61	220%	4.91	5%	72.52	236%
6	44.40	190.32	199.84	145.92	329%	9.52	5%	155.44	350%
8	79.80	300.66	315.70	220.86	277%	15.04	5%	235.90	296%
10	148.00	778.83	817.78	630.83	426%	38.95	5%	669.78	453%

*Rate Study column is the Department's 2018 Comprehensive Water, Sewer and Stormwater Rate Study proposed change over the current rate column. The proposed rate is the proposed increase on top of the rate study rates

Comparison of Water Monthly Usage Rate Options for City Residential Customers

Flat Rate or Block	2019 Current Rate per ccf	2019 Rate Study per ccf	2020 Proposed Rate per ccf	Changes: Current to Rate Study $	%	Rate Study to Proposed $	%	Current to Proposed $	%
Winter Rate Structure (November - March)									
Flat Rate	1.35	1.30	1.37	-0.05	-4%	0.07	5%	0.02	1%
Summer Rate Structure (April - October)									
Block 1	1.35	1.30	1.37	-0.05	-4%	0.07	5%	0.02	1%
Block 2	1.85	1.78	1.87	-0.07	-4%	0.09	5%	0.02	1%
Block 3	2.57	2.47	2.59	-0.10	-4%	0.12	5%	0.02	1%
Block 4	2.74	2.63	2.76	-0.11	-4%	0.13	5%	0.02	1%

Comparison of Water Monthly Usage Rate Options for County Residential Customers

Flat Rate or Block	2019 Current Rate per ccf	2019 Rate Study per ccf	2020 Proposed Rate per ccf	Changes: Current to Rate Study $	%	Rate Study to Proposed $	%	Current to Proposed $	%
Winter Rate Structure (November - March)									
Flat Rate	1.82	1.76	1.84	-0.07	-4%	0.09	5%	0.02	1%
Summer Rate Structure (April - October)									
Block 1	1.82	1.76	1.84	-0.06	-3%	0.08	5%	0.02	1%
Block 2	2.50	2.40	2.52	-0.10	-4%	0.12	5%	0.02	1%
Block 3	3.47	3.33	3.50	-0.14	-4%	0.17	5%	0.03	1%
Block 4	3.70	3.55	3.73	-0.15	-4%	0.18	5%	0.03	1%

Rate Structure (Same for City and County)

Block	Current	Study	Proposed
Flat Rate	All Usage	All Usage	All Usage
Block 1	1 - 10 ccf	1 - 10 ccf	1 - 10 ccf
Block 2	11 - 30 ccf	11 - 30 ccf	11 - 30 ccf
Block 3	31 - 70 ccf	31 - 60 ccf	31 - 60 ccf
Block 4	>71 ccf	>61 ccf	>61 ccf

Comparison of Monthly Usage Rate Options
for City CII Customers

Flat Rate or Block	2019 Current Rate per ccf	2019 Rate Study per ccf	2020 Proposed Rate per ccf	Changes: Current to Rate Study $	%	Rate Study to Proposed $	%	Current to Proposed $	%
Winter Rate Structure (November - March)									
Flat Rate	1.35	1.42	1.49	0.07	5%	0.07	5%	0.14	10%
Summer Rate Structure (April - October)									
Block 1	1.35	1.42	1.49	0.07	5%	0.07	5%	0.14	10%
Block 2	1.85	1.94	2.04	0.09	5%	0.10	5%	0.19	10%
Block 3	2.57	2.70	2.84	0.13	5%	0.14	5%	0.27	11%
Block 4	2.47	2.87	3.01	0.40	16%	0.14	5%	0.54	22%

Comparison of Monthly Usage Rate Options
for County CII Customers

Flat Rate or Block	2019 Current Rate per ccf	2019 Rate Study per ccf	2020 Proposed Rate per ccf	Changes: Current to Rate Study $	%	Rate Study to Proposed $	%	Current to Proposed $	%
Winter Rate Structure (November - March)									
Flat Rate	1.82	1.92	2.01	0.09	5%	0.09	5%	0.19	10%
Summer Rate Structure (April - October)									
Block 1	1.82	1.92	2.01	0.09	5%	0.09	5%	0.19	10%
Block 2	2.50	2.62	2.75	0.12	5%	0.14	5%	0.26	10%
Block 3	3.47	3.65	3.83	0.18	5%	0.19	5%	0.36	11%
Block 4	3.33	3.87	4.06	0.54	16%	0.19	5%	0.73	22%

Rate Structure (Same for City and County)

Block	Current	Study	Proposed
Flat Rate	All Usage	All Usage	All Usage
Block 1	0-AWC	0-AWC	0-AWC
Block 2	AWC-300%	AWC-300%	AWC-300%
Block 3	300%-700%	300%-600%	300%-600%
Block 4	>700%	>600%	>600%

*CII= Commercial, Industrial, and Institutional
*AWC = Average Winter Consumption. “AWC-300%” means usage greater than a customer’s AWC and less than or equal to

Comparison of Water Monthly Usage Rate Options
for City Irrigation Customers

Flat Rate or Block	2019 Current Rate per ccf	2019 Rate Study per ccf	2020 Proposed Rate per ccf	Changes: Current to Rate Study $	%	Rate Study to Proposed $	%	Current to Proposed $	%
Winter Rate Structure (November - March)									
Flat Rate	1.85	1.71	1.80	-0.14	-8%	0.09	5%	-0.05	-3%
Summer Rate Structure (April - October)									
Block 1	1.85	1.71	1.80	-0.14	-8%	0.09	5%	-0.05	-3%
Block 2	2.57	2.38	2.50	-0.19	-7%	0.12	5%	-0.07	-3%
Block 3	2.74	2.53	2.66	-0.21	-8%	0.13	5%	-0.08	-3%

Comparison of Water Monthly Usage Rate Options
for County Irrigation Customers

Flat Rate or Block	2019 Current Rate per ccf	2019 Rate Study per ccf	2020 Proposed Rate per ccf	Changes: Current to Rate Study $	%	Rate Study to Proposed $	%	Current to Proposed $	%
Winter Rate Structure (November - March)									
Flat Rate	2.50	2.31	2.42	-0.19	-8%	0.12	5%	-0.07	-3%
Summer Rate Structure (April - October)									
Block 1	2.50	2.31	2.42	-0.19	-8%	0.12	5%	-0.07	-3%
Block 2	3.47	3.21	3.37	-0.26	-7%	0.16	5%	-0.10	-3%
Block 3	3.70	3.42	3.59	-0.28	-8%	0.17	5%	-0.11	-3%

Rate Structure (Same for City and County)

Block	Current	Study	Proposed
Flat Rate	All Usage	All Usage	All Usage
Block 1	1CCF-Target Budget	1CCF-Target Budget	1CCF-Target Budget
Block 2	Target Budget up to 300% of Target Budget	Target Budget up to 300% of Target Budget	Target Budget up to 300% of Target Budget
Block 3	Over 300% of Target Budget	Over 300% of Target Budget	Over 300% of Target Budget

* "Target budget" means the estimated amount of water consumed per acre, as established by the Public Utilities Director or his/her designee each year for customer based on factors including, but not limited to, evapotranspiration, and considering efficient water practices. A different target budget is established for each month of the irrigation season.

<u>Proposed Water Rate Change Customer Impacts</u>

Water Rate Change
Annual Impact on Select City Customers

Account Type	Annual Usage	Meter Size	2019 Current Rate	2020 Proposed Rate	$ Change	% Change
Residential Minimum Use	72 ccf	3/4	215.88	210.00	(5.88)	-2.72%
Residential Low Use	96 ccf	3/4	248.28	242.88	(5.40)	-2.17%
Residential Medium Use	255 ccf	3/4	559.17	556.95	(2.22)	-0.40%
Residential High Use	838 ccf	1	1,973.18	2,016.94	43.76	2.22%
Industrial Use	96,476 ccf	2	140,552.76	151,270.96	10,718.20	7.63%
Commercial Use	11,597 ccf	2	16,365.71	17,684.93	1,319.22	8.06%

Water Rate Change
Monthly Impact on Select City Customers

Account Type	Monthly Usage	Meter Size	2019 Current Rate	2020 Proposed Rate	$ Change	% Change
Residential Minimum Use	6 ccf	3/4	17.99	17.50	(0.49)	-2.72%
Residential Low Use	8 ccf	3/4	20.69	20.24	(0.45)	-2.17%
Residential Medium Use	21 ccf	3/4	46.60	46.41	(0.18)	-0.40%
Residential High Use	70 ccf	1	164.43	168.08	3.65	2.22%
Industrial Use	8,040 ccf	2	11,712.73	12,605.91	893.18	7.63%
Commercial Use	966 ccf	2	1,363.81	1,473.74	109.94	8.06%

Water Rate Change
Annual Impact on Select County Customers

Account Type	Annual Usage	Meter Size	2019 Current Rate	2020 Proposed Rate	$ Change	% Change
Residential Minimum Use	72 ccf	3/4	291.44	283.50	(7.94)	-2.72%
Residential Low Use	96 ccf	3/4	335.18	327.89	(7.29)	-2.17%
Residential Medium Use	255 ccf	3/4	754.88	751.88	(3.00)	-0.40%
Residential High Use	838 ccf	1	2,663.79	2,722.87	59.08	2.22%
Industrial Use	96,476 ccf	2	189,746.23	204,215.80	14,469.57	7.63%
Commercial Use	11,597 ccf	2	22,093.71	23,874.66	1,780.95	8.06%

Water Rate Change
Monthly Impact on Select County Customers

Account Type	Monthly Usage	Meter Size	2019 Current Rate	2020 Proposed Rate	$ Change	% Change
Residential Minimum Use	6 ccf	3/4	24.29	23.63	(0.66)	-2.72%
Residential Low Use	8 ccf	3/4	27.93	27.32	(0.61)	-2.17%
Residential Medium Use	21 ccf	3/4	62.91	62.66	(0.25)	-0.40%
Residential High Use	70 ccf	1	221.98	226.91	4.92	2.22%
Industrial Use	8,040 ccf	2	15,812.19	17,017.98	1,205.80	7.63%
Commercial Use	966 ccf	2	1,841.14	1,989.55	148.41	8.06%

Sewer Rate Change Comparisons

Comparison of Monthly Sewer Class Rate Changes

Flow $ Per CCF

	2019	2019	2020	Changes					
Class	Current Rate	Rate Study	Proposed Rate	Current to Rate Study		Rate Study to Proposed		Current to Proposed	
				$	%	$	%	$	%
1	1.86	1.94	2.29	0.08	4%	0.35	18%	0.43	23%
2	1.86	1.94	2.29	0.08	4%	0.35	18%	0.43	23%
3	1.86	1.94	2.29	0.08	4%	0.35	18%	0.43	23%
4	1.86	1.94	2.29	0.08	4%	0.35	18%	0.43	23%
5	1.86	1.94	2.29	0.08	4%	0.35	18%	0.43	23%
6	1.86	1.94	2.29	0.08	4%	0.35	18%	0.43	23%
7	Special Rate by Customer								

BOD $ Per CCF

	2019	2019	2020	Changes					
Class	Current Rate	Rate Study	Proposed Rate	Current to Rate Study		Rate Study to Proposed		Current to Proposed	
				$	%	$	%	$	%
1	0.78	0.68	0.80	-0.10	-13%	0.12	18%	0.02	3%
2	1.28	1.11	1.31	-0.17	-13%	0.20	18%	0.03	2%
3	2.10	1.83	2.16	-0.27	-13%	0.33	18%	0.06	3%
4	3.01	2.62	3.09	-0.39	-13%	0.47	18%	0.08	3%
5	3.80	3.29	3.88	-0.51	-13%	0.59	18%	0.08	2%
6	4.67	4.05	4.78	-0.62	-13%	0.73	18%	0.11	2%
7	Special Rate by Customer								

TSS $ Per CCF

	2019	2019	2020	Changes					
Class	Current Rate	Rate Study	Proposed Rate	Current to Rate Study		Rate Study to Proposed		Current to Proposed	
				$	%	$	%	$	%
1	0.40	0.49	0.58	0.09	4%	0.35	18%	0.18	45%
2	0.82	1.00	1.18	0.18	4%	0.35	18%	0.36	44%
3	1.39	1.70	2.01	0.31	4%	0.35	18%	0.62	44%
4	1.90	2.32	2.74	0.42	4%	0.35	18%	0.84	44%
5	2.46	3.01	3.55	0.55	4%	0.35	18%	1.09	44%
6	2.98	3.65	4.31	0.67	4%	0.35	18%	1.33	45%
7	Special Rate by Customer								

Total Sewer Rate Per CCF

	2019	2019	2020	Changes					
Class	Current Rate	Rate Study	Proposed Rate	Current to Rate Study		Rate Study to Proposed		Current to Proposed	
				$	%	$	%	$	%
1	3.04	3.11	3.67	0.07	-13%	0.12	18%	0.63	21%
2	3.96	4.05	4.78	0.09	-13%	0.20	18%	0.82	21%
3	5.35	5.47	6.45	0.12	-13%	0.33	18%	1.10	21%
4	6.77	6.88	8.12	0.11	-13%	0.47	18%	1.35	20%
5	8.12	8.24	9.72	0.12	-13%	0.59	18%	1.60	20%
6	9.51	9.64	11.38	0.13	-13%	0.73	18%	1.87	20%
7	Special Rate by Customer								

Class Structure

Block	BOD Strength mg/l	TSS Strength mg/l
1	0-300	0-300
2	300-600	300-600
3	600-900	600-900
4	900-1200	900-1200
5	1200-1500	1200-1500
6	1500-1800	1500-1800
7	>1800	>1800

Proposed Sewer Rate Change Customer Impacts

Sewer Rate Change
Annual Impact on Select City Customers

Account Type	Annualized Average Winter Water Usage (CCF)	2019 Current Rate	2020 Proposed Rate	$ Changes	% Change
Residential Minimum Use	24 ccf	145.92	88.08	(57.84)	-39.64%
Residential Low Use	48 ccf	145.92	176.16	30.24	20.72%
Residential Medium Use	96 ccf	291.84	352.32	60.48	20.72%
Residential High Use	180 ccf	547.20	660.60	113.40	20.72%
Industrial 2,4	24,168 ccf	121,806.72	137,999.28	16,192.56	13.29%
Commercial 2,1	408 ccf	1,444.32	1,530.00	85.68	5.93%

*Industrial & Commercial charges are calculated based on flow rate, BOD and TSS

Sewer Rate Change
Monthly Impact on Select City Customers

Account Type	Annualized Average Winter Water Usage (CCF)	2019 Current Rate	2020 Proposed Rate	$ Changes	% Change
Residential Minimum Use	2 ccf	12.16	7.34	(4.82)	-39.64%
Residential Low Use	4 ccf	12.16	14.68	2.52	20.72%
Residential Medium Use	8 ccf	24.32	29.36	5.04	20.72%
Residential High Use	15 ccf	45.60	55.05	9.45	20.72%
Industrial 2, 4	2,014 ccf	10,150.56	11,499.94	1,349.38	13.29%
Commercial 2,1	34 ccf	120.36	127.50	7.14	5.93%

*Industrial & Commercial charges are calculated based on flow rate, BOD and TSS

Stormwater Rate Change Comparisons

Comparison of Monthly Stormwater Rate Changes

		2019	2020	Changes Current to	
Account Type	**ERUs**	**Current Rate**	**Proposed Rate**	**$**	**%**
Single and Duplex <.25 Acre	All ERU	4.94	5.43	0.49	9.92%
Single and Duplex >.25 Acre	All ERU	6.91	7.60	0.69	9.99%
Triplex and Fourplex	All ERU	9.88	10.87	0.99	10.02%
All other Parcels	Per ERU	4.94	5.43	0.49	9.92%

*1 ERU = 1 residential property or 75 feet of street frontage for non-residential properties

Proposed Stormwater Rate Change Customer Impacts

Stormwater Rate Change
Annual Impact on Select City Customers

		2019	2020	Changes Current to Proposed	
Account Type	ERUs	Current Rate	Proposed Rate	$	%
Residential less than .25 Acre	Any ERU	59.28	65.16	5.88	9.92%
Residential more than .25 Acre	Any ERU	82.92	91.20	8.28	9.99%
Industrial*	300 ERU	1,482.00	1,629.00	147.00	9.92%
Commercial	120 ERU	592.80	651.60	58.80	9.92%

Stormwater Rate Change
Monthly Impact on Select City Customers

		2019	2020	Changes Current to Proposed	
Account Type	ERUs	Current Rate	Proposed Rate	$	%
Residential less than .25 Acre	Any ERU	4.94	5.43	0.49	9.92%
Residential more than .25 Acre	Any ERU	6.91	7.60	0.69	9.99%
Industrial	25 ERU	123.50	135.75	12.25	9.92%
Commercial	10 ERU	49.40	54.30	4.90	9.92%

APPENDIX E: Supplemental Information

Water Rates Compared with Recognizable Cities in Western States

Ranking	City or District Name	Average Monthly Charge
1	Flagstaff, AZ (1)	$ 121.40
2	Cheyenne, WY (2)	$ 68.60
3	Denver, CO (3)	$ 56.34
4	Reno, NV (4)	$ 51.14
5	Phoenix, AZ (5)	$ 44.67
6	Boise, ID (6)	$ 44.44
7	Las Vegas, NV (7)	$ 42.26
8	Salt Lake City, UT- 2019 Current	$ 37.44
	Salt Lake City, UT- 2020 Proposed	$ 37.17
9	Henderson, NV (8)	$ 26.47

* Cities compared with 7,480 gallons per month (10 CCF) and 24,000 gallons summer usage (32.09 CCF).
** Based on eight months Winter and four months Summer usage

Sewer Rates Compared with Nearby States

City or District Name	Average Monthly Charges
Reno, NV	$ 46.77
Boise, ID **	$ 43.33
Phoenix, AZ **	$ 37.02
Flagstaff, AZ	$ 29.92
Cheyenne, WY **	$ 29.32
Salt Lake City- 2020 Proposed	$ 29.36
Denver, CO	$ 26.99
Henderson, NV	$ 25.78
Salt Lake City- 2019 Current	$ 24.32
Las Vegas, NV	$ 19.76

* Monthly Average Charges calculated based on 5,984 gallons per month (or 8 CCF)
** Includes Monthly base rate

Sewer Rates Compared with Local Cities November 2018

Ranking	City or District Name	Annual Charge
1	City of South Salt Lake	$ 502.66
2	Kearns Improvement District	$ 425.34
3	Magna City	$ 381.63
4	Ogden City	$ 364.56
	Salt Lake City- 2020 Proposed	$ 352.32
5	South Valley Sewer District	$ 332.56
6	Murray City **	$ 323.63
7	West Jordan City **	$ 323.09
8	Granger - Hunter Improvement District	$ 322.55
9	Midvalley Improvement District	$ 295.29
10	Salt Lake City- 2019 Current	$ 291.84
11	Taylorsville - Bennion Improvement District**	$ 265.95
12	Cottonwood Improvement District	$ 259.36
13	Sandy Suburban Improvement District	$ 257.04
14	Mt Olympus Improvement District	$ 234.69
15	South Davis Sewer District	$ 146.95

* Annual cost based on 12 months at 5,984 gallons per month (or 8 CCF per month) average winter consumption. Flat rate based on monthly rate multiplied by 12.

** Includes monthly base rate

Stormwater Rates Compared with Local Cities November 2018

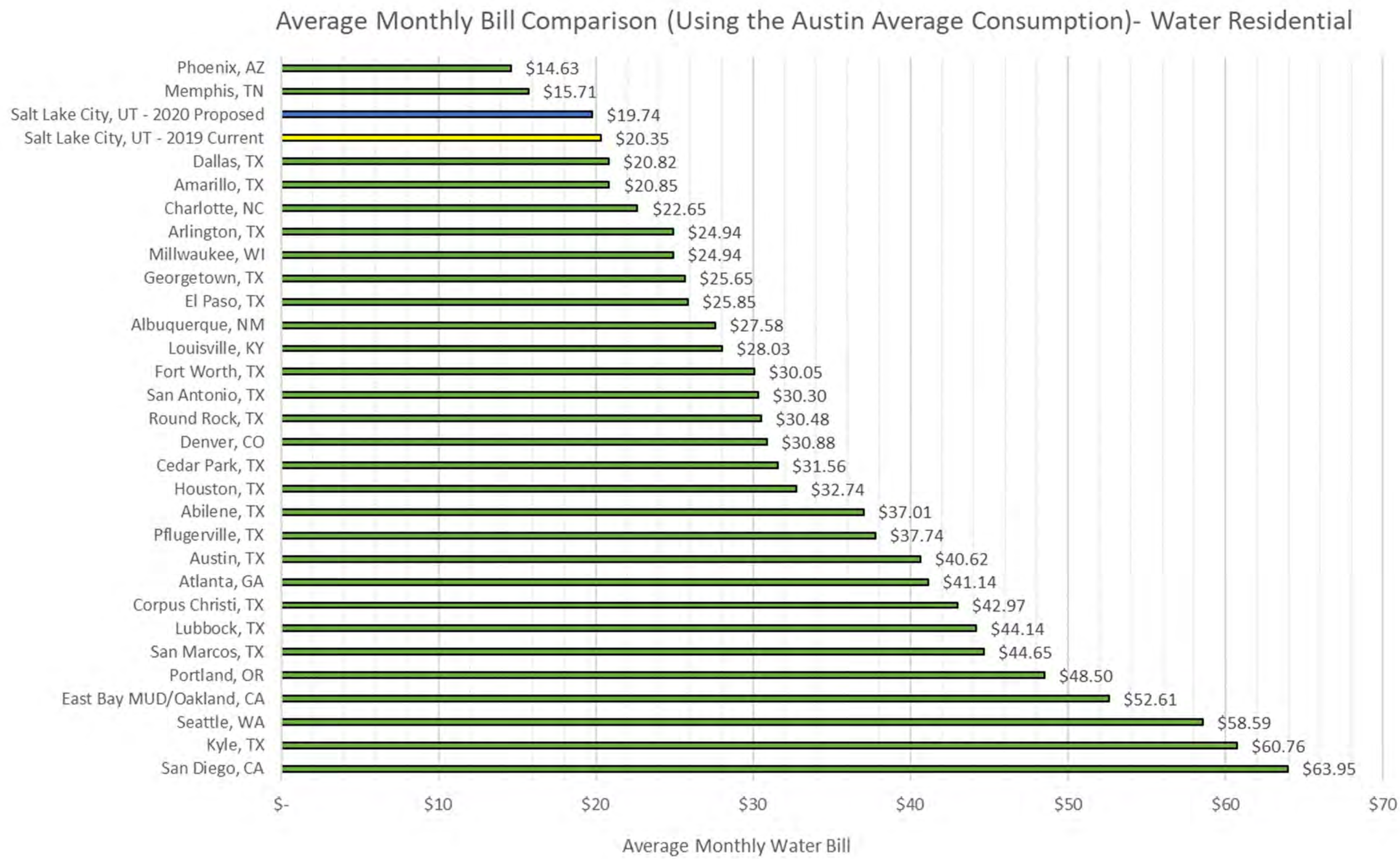
RANKING	CITY NAME	CURRENT RATE
1	PLEASANT GROVE	12.48
2	PROVO	9.20
3	DRAPER CITY	9.00
4	OGDEN CITY	7.85
5	SOUTH JORDAN CITY	7.15
6	BOUNTIFUL CITY	7.00
7	OREM	6.75
8	AMERICAN FORK	6.00
8	SANDY CITY	6.00
	SALT LAKE CITY (PROPOSED)	5.43
9	SALT LAKE CITY (Current)	4.94
10	MURRAY CITY	4.65
11	WEST JORDAN CITY	4.50
12	TAYLORSVILLE CITY	4.00

Public Utilities Department Local Area Water Rate Comparison
November 2018 (Highest to Lowest Ranking)

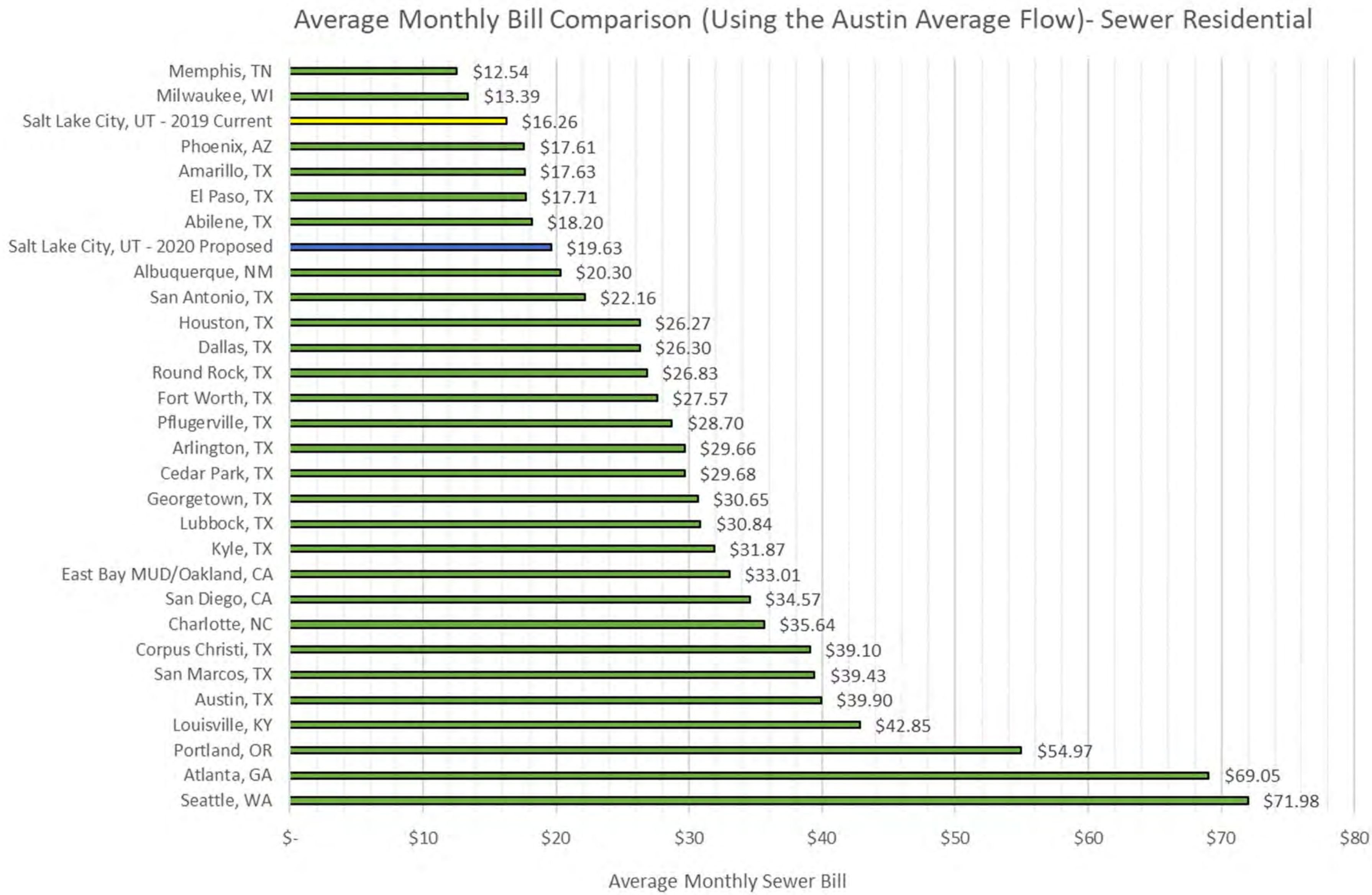
RANKING	CITY OR DISTRICT NAME	MONTHLY MINIMUM CHARGE	MINIMUM ALLOWANCE IN GALLONS	RATE OVER MINIMUM ALLOWANCE	PER GALLONS	MONTHLY FLOURIDE CHARGE	WINTER @ 7,480 GAL PER MONTH	SUMMER @ 23,936 GAL PER MONTH	TOTAL WINTER CHARGES*	TOTAL SUMMER CHARGES*	YEARLY TAX ON $200,000 PROPERTY	TOTAL CHARGES
1	PARK CITY - GRADUATED RATES (1)	49.08	0	6.12 - 10.31	1,000		104.01	269.91	832.07	1079.64		1911.71
2	AMERICAN FORK - GRADUATED RATES (2)	22.67	3,000	3.52 - 4.96	1,000		39.51	120.03	316.04	480.13		796.17
3	DRAPER CITY - GRADUATED RATES (3)	20.25	0	2.05 - 3.71	1,000		39.08	97.00	312.65	388.01		700.66
4	SOUTH JORDAN CITY - GRADUATED RATES (4)	30.00	0	2.00 - 2.50	1,000		45.33	84.09	362.64	336.36		699.00
5	RIVERTON CITY - GRADUATED RATES (5)	2.50	0	3.76 - 3.91	1,000		31.00	95.34	247.97	381.36		629.33
6	PLEASANT GROVE - GRADUATED RATES (6)	20.81	5,000	2.52 - 5.27	1,000		27.06	98.90	216.48	395.61		612.09
7	OGDEN CITY - GRADUATED RATES (7)	20.90	0	1.79 - 2.74	1,000		35.70	80.78	285.56	323.14		608.70
8	SALT LAKE CITY - OUTSIDE OF CITY	13.35	0	1.82 - 3.47	748		31.55	88.49	252.40	353.96		606.36
	SALT LAKE CITY - OUTSIDE OF CITY (Proposed)	12.53	0	1.84 -3.50	748		30.93	88.33	247.44	353.32		600.76
9	SANDY CITY - OUTSIDE OF CITY (8)	19.95	0	1.80 - 2.75	1,000		34.82	80.07	278.56	320.30		598.86
10	WEST JORDAN CITY (11)	26.58	0	1.65 - 2.18	1,000		39.04	71.41	312.34	285.64		597.98
11	KEARNS IMPROVEMENT DIST-GRADUATED RATES (9)	11.60	0	2.33 - 2.92	1,000		29.03	75.59	232.23	302.37	51.04	585.64
12	MAGNA - GRADUATED RATES (10)	17.41	6,000	1.89 - 2.12	1,000	0.98	21.19	53.65	169.50	214.62	178.81	562.92
13	SANDY CITY - INSIDE OF CITY (12)	14.43	0	1.64 - 2.53	1,000		28.01	69.65	224.12	278.59	35.75	538.46
14	SALT LAKE CITY - INSIDE OF CITY (13)	9.89	0	1.35 - 2.57	748		23.39	65.53	187.12	262.12	33.22	482.46
	SALT LAKE CITY - INSIDE OF CITY (Proposed)	9.28	0	1.37 - 2.59	748		22.98	65.56	183.84	262.24	35.75	481.83
15	BOUNTIFUL CITY - RESIDENTIAL HIGH ELEVATION	23.57	5,000	1.98	1,000		28.48	61.06	227.84	244.25		472.10
16	CITY OF SOUTH SALT LAKE	19.00	5,000	2.25	1,000	2.00	26.58	63.61	212.64	254.42		467.06
17	GRANGER - HUNTER IMPROVEMENT DISTRICT (14)	13.00	0	1.61 -1.86	1,000		25.10	54.73	200.80	218.92	28.55	448.27
18	BOUNTIFUL CITY - RESIDENTIAL LOW ELEVATION	21.39	5,000	1.79	1,000		25.83	55.29	206.63	221.14		427.78
19	JVWCD	3.00	0	1.87 - 2.34	1,000		16.99	59.01	135.90	236.04	44.00	415.94
20	PROVO	15.29	0	0.87 - 1.44	1,000		21.80	49.76	174.38	199.03		373.41
21	TAYLORSVILLE/BENNION IMPROVEMENT DISTRICT (15	7.00	0	1.43 - 1.87	1,000		18.35	49.12	146.78	196.48	6.88	350.14
22	MURRAY CITY - GRADUATED RATES (16)	10.00	0	0.95 - 1.40	748		19.90	46.95	159.20	187.80		347.00
23	OREM - GRADUATED RATES (17)	17.16	0	0.79 - 0.99	1,000		23.07	38.66	184.55	154.63		339.18

CALCULATION OF COMPARISONS

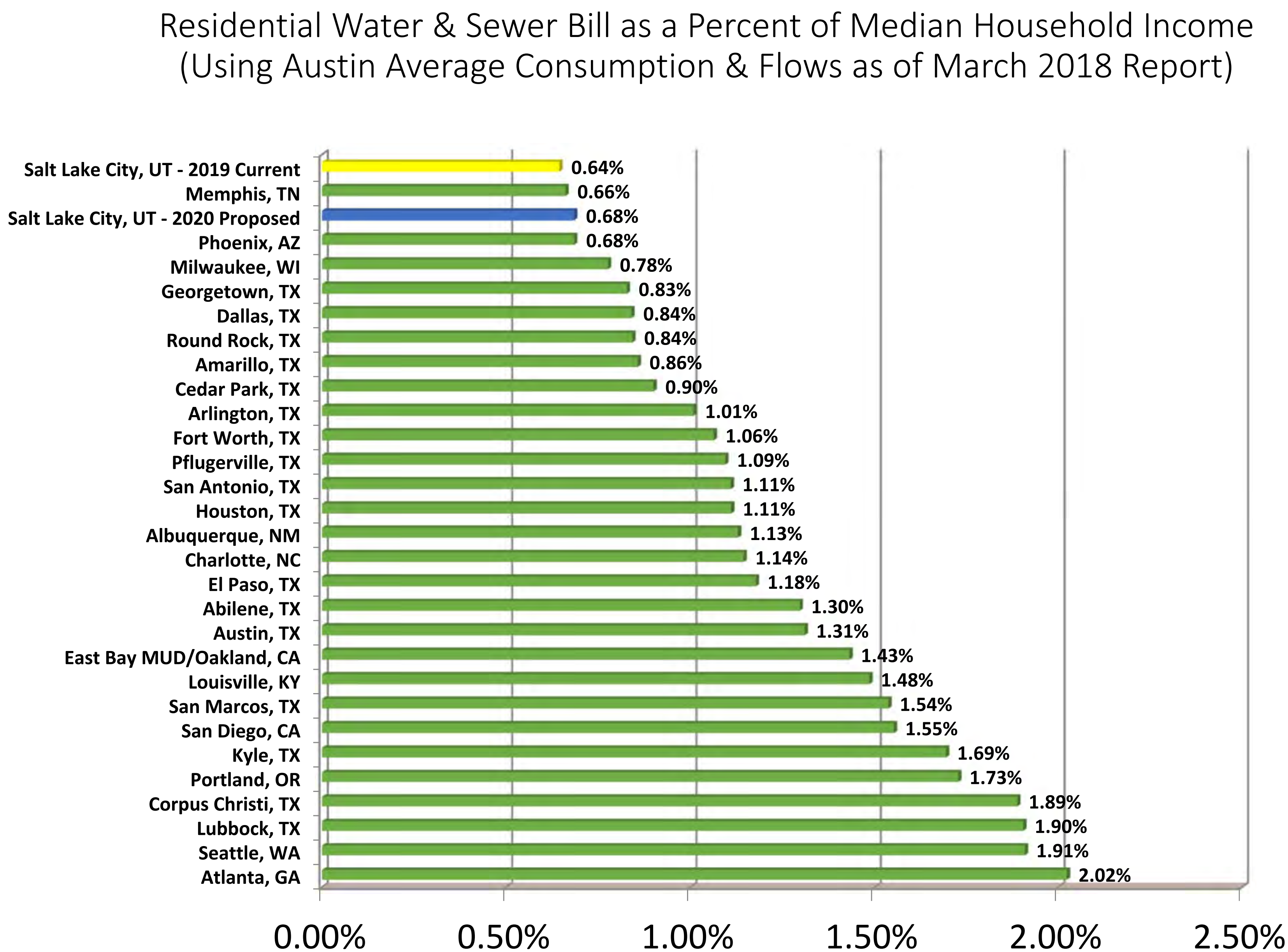
** BASED ON EIGHT MONTHS WINTER AND FOUR MONTHS SUMMER*
(1) RATES ARE $6.12/THOUSAND FOR 0-5,000 GALLONS, $9.81/THOUSAND FOR 5,001-15,000 GALLONS, & $10.31/THOUSAND FOR 15,001-25,000 GALLONS
(2) RATES ARE $22.67 FOR 0-3,000 GALLONS, $3.52/THOUSAND FOR 3,001-6,000 GALLONS, $4.24/THOUSAND FOR 6,000-9,000 GAL & $4.96/THOUSAND OVER 9,000 GALLONS
(3) RATES ARE $2.05/THOUSAND FOR 0-5,000 GALLONS, $3.46/THOUSAND FOR 5,001-20,000 GALLONS, & $3.71/THOUSAND FOR 20,001-50,000 GALLONS
(4) RATES ARE $2.00/THOUSAND FOR 0-6,000 GALLONS, $2.25/THOUSAND FOR 6,001-17,000 GALLLONS & $2.50/THOUSAND FOR 17,001 - 42,000 GALLONS
(5) RATES ARE $3.76 FOR 0-5,000 GALLONS & $3.91/THOUSAND OVER 5,000 GALLONS
(6) RATES ARE $20.81 FOR 0-5,000 GALLONS, $2.52/THOUSAND FOR 5,001-10,000 GALLONS, $3.68/THOUSAND FOR 10,001-15,000 GALLONS & $5.27/THOUSAND OVER 15,000 GALLONS
(7) RATES ARE $1.79/THOUSAND FOR 0-6,000 GALLONS & $2.74/THOUSAND FOR 6,001-42,000 GALLONS
(8) RATES ARE $1.80/THOUSAND FOR 0-6,000 GALLONS & $2.75/THOUSAND FOR 6,001-40,000 GALLONS
(9) RATES ARE $2.33/THOUSAND FOR 0-10,000 GALLONS & $2.92/THOUSAND FOR 10,001-25,000 GALLONS
(10) RATES ARE $1.64/THOUSAND FOR 0-6,000 GALLONS & $2.53/THOUSAND FOR 6,001-40,000 GALLONS
(11) RATES ARE $17.41 FOR 0-6,000 GALLONS, $1.89/THOUSAND FOR 6,001-18,000 GALLONS, & $2.12/THOUSAND FOR 18,001-35,000 GALLONS
(12) RATES ARE $1.65 FOR 0-7,000 GALLONS, $1.90/THOUSAND FOR 7,001-20,000 GALLONS, & $2.18/THOUSAND FOR OVER 20,000 GALLONS
(13) INCLUDES METROPOLITAN WATER PROPERTY TAX
(14) RATES ARE $1.61/THOUSAND FOR 0-7,000 GALLONS, $1.73/THOUSAND FOR 7,001-15,000 GALLONS & $1.86/THOUSAND FOR OVER 15,000 GALLONS
(15) RATES ARE $1.43/THOUSAND FOR 0-6,000 GALLONS & $1.87/THOUSAND FOR 6,001-25,000 GALLONS
(16) RATES ARE $.95/HUNDRED FOR 0-8 HCF, $1.15/HUNDRED FOR 9-25 HCF & $1.40/HUNDRED FOR 26-49 HCF
(17) RATES ARE $.79/THOUSAND FOR 0-11,000 GALLONS, $.99/THOUSAND FOR 11,001-34,000 GALLONS



*Cities Other than SLC- Data Source Rates from March 2018 Austin National Survey
** Rates Calculated of an average of 5,800 gallons a month or 7.54 CCF

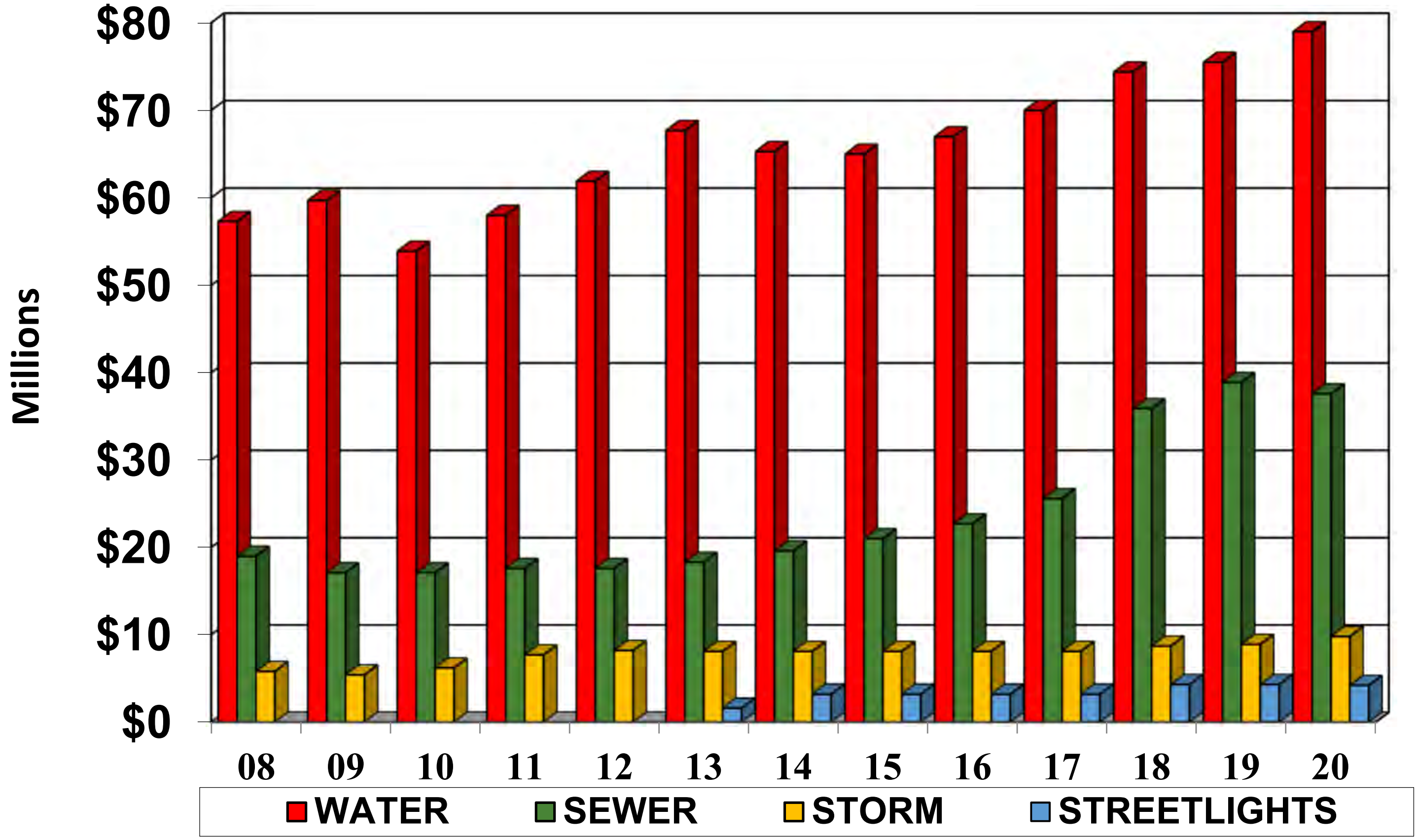


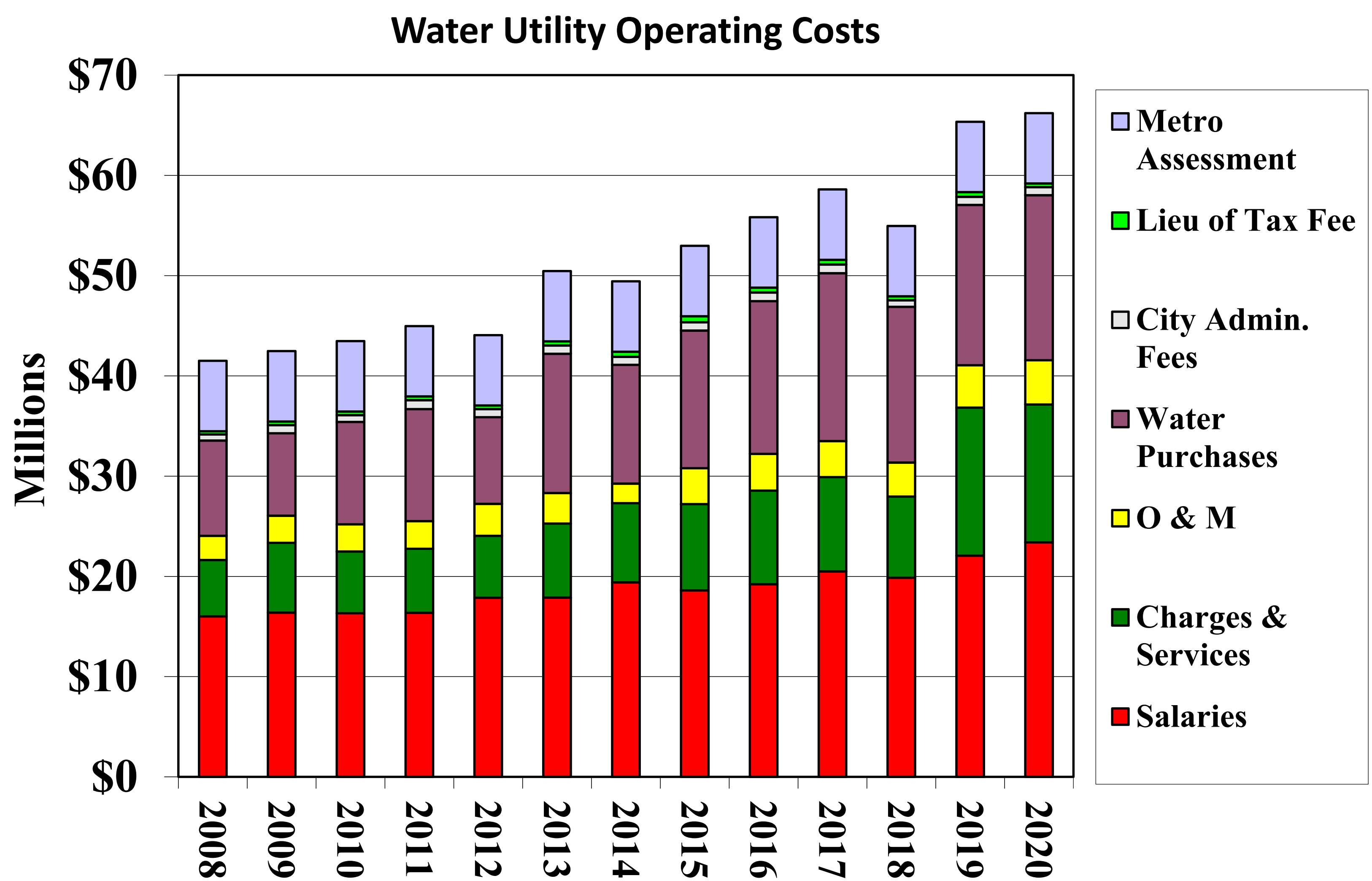
*Cities Other than SLC- Data Source Rates from March 2018 Austin National Survey
** Rates Calculated of an average of 4,000 gallons a month or 5.35 CCF

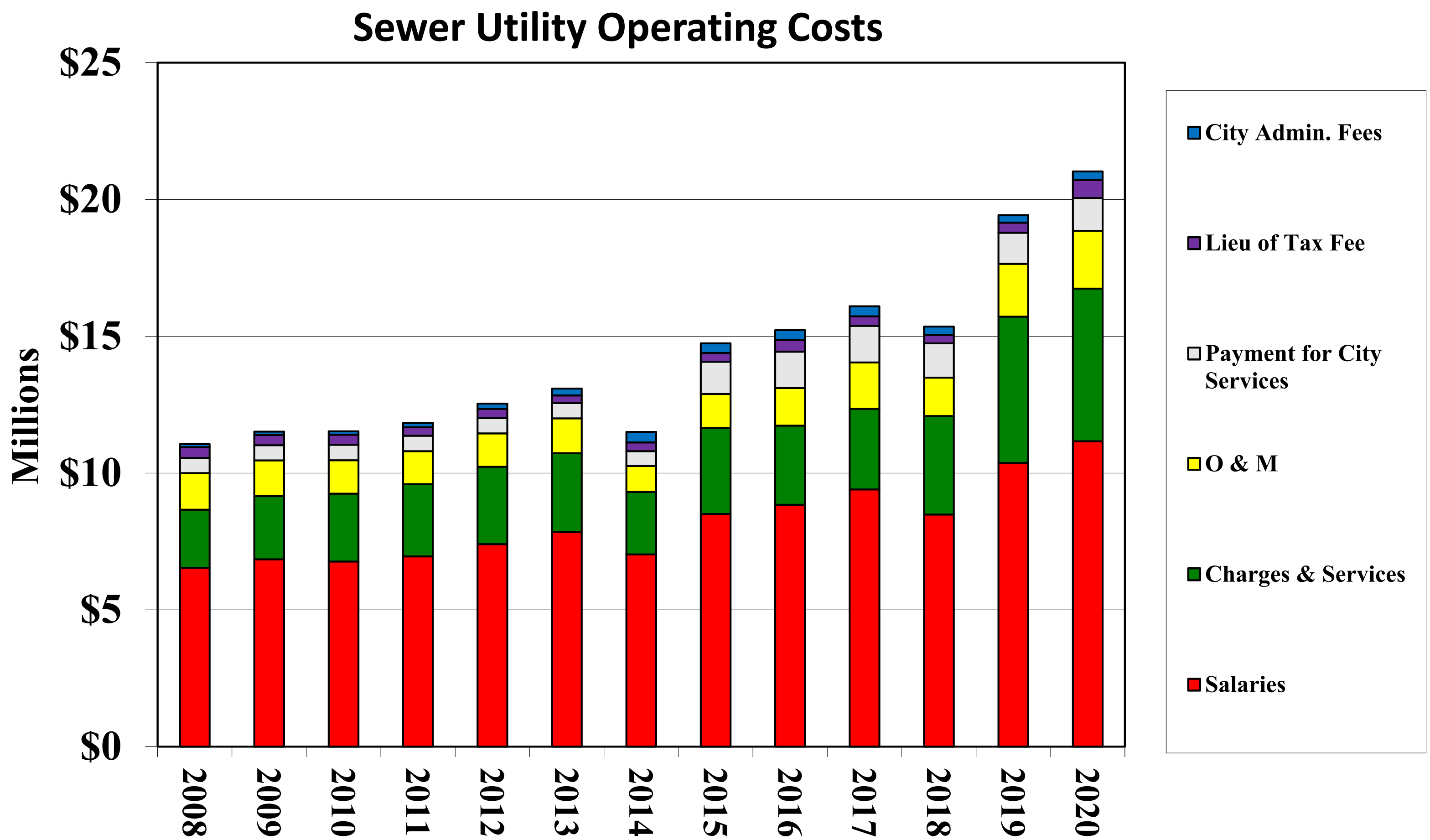


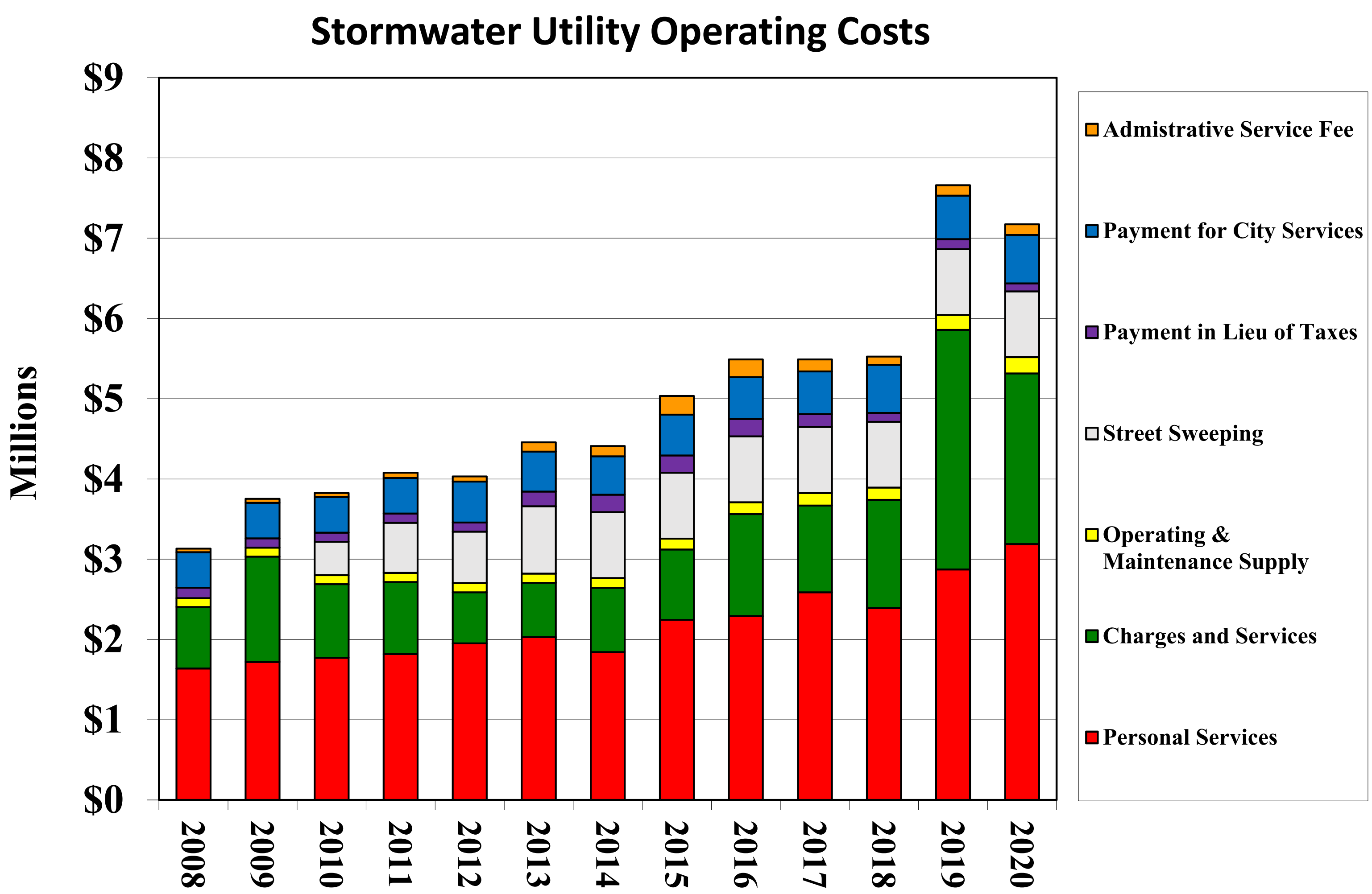
* The percentage of median household income was calculated by taking the results of each individual city's bill based on that city's rates and the usage of the Austin average consumption and flows. From those results, we divide the annual amount by the individual city's 10 year average median income.
** Median Income source: www.deptofnumbers.com/income/us/l

Public Utilities Operating Revenue

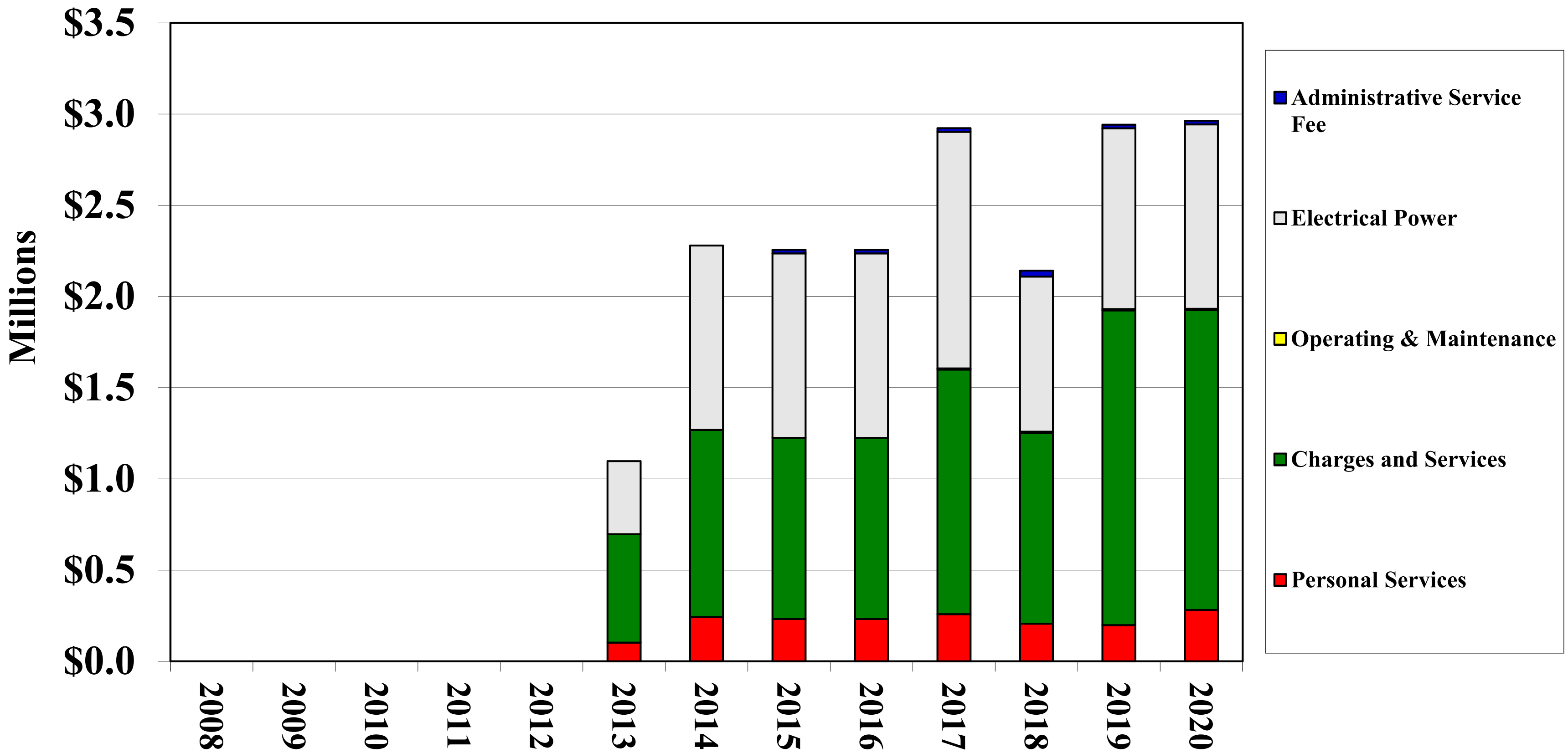



Water Utility Operating Costs
$70
$60
$50
$40
$30
$20
$10
$0
Millions
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
Metro Assessment
Lieu of Tax Fee
City Admin. Fees
Water Purchases
O & M
Charges & Services
Salaries

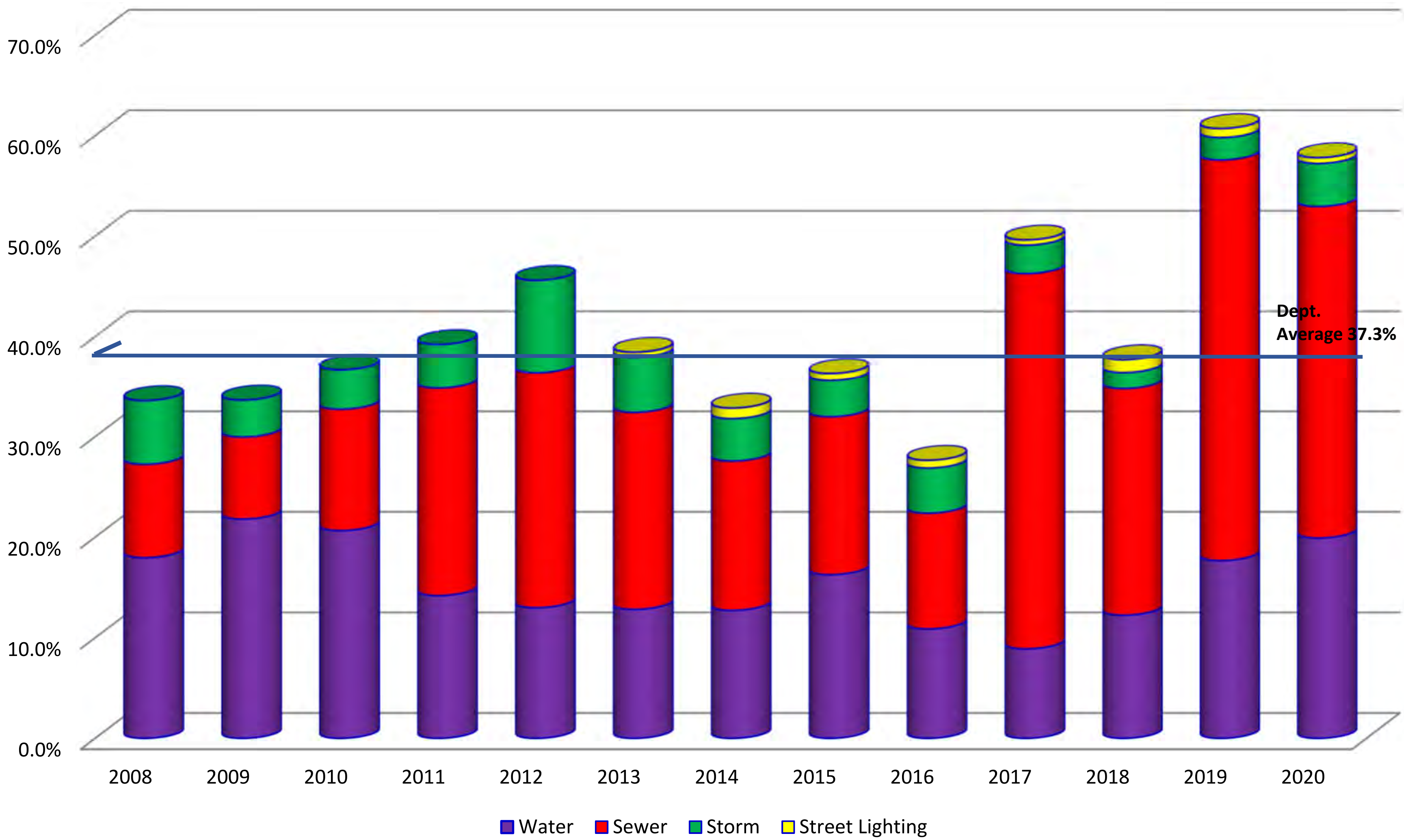

Sewer Utility Operating Costs
$25
$20
$15
$10
$5
$0
Millions
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
City Admin. Fees
Lieu of Tax Fee
Payment for City Services
O & M
Charges & Services
Salaries

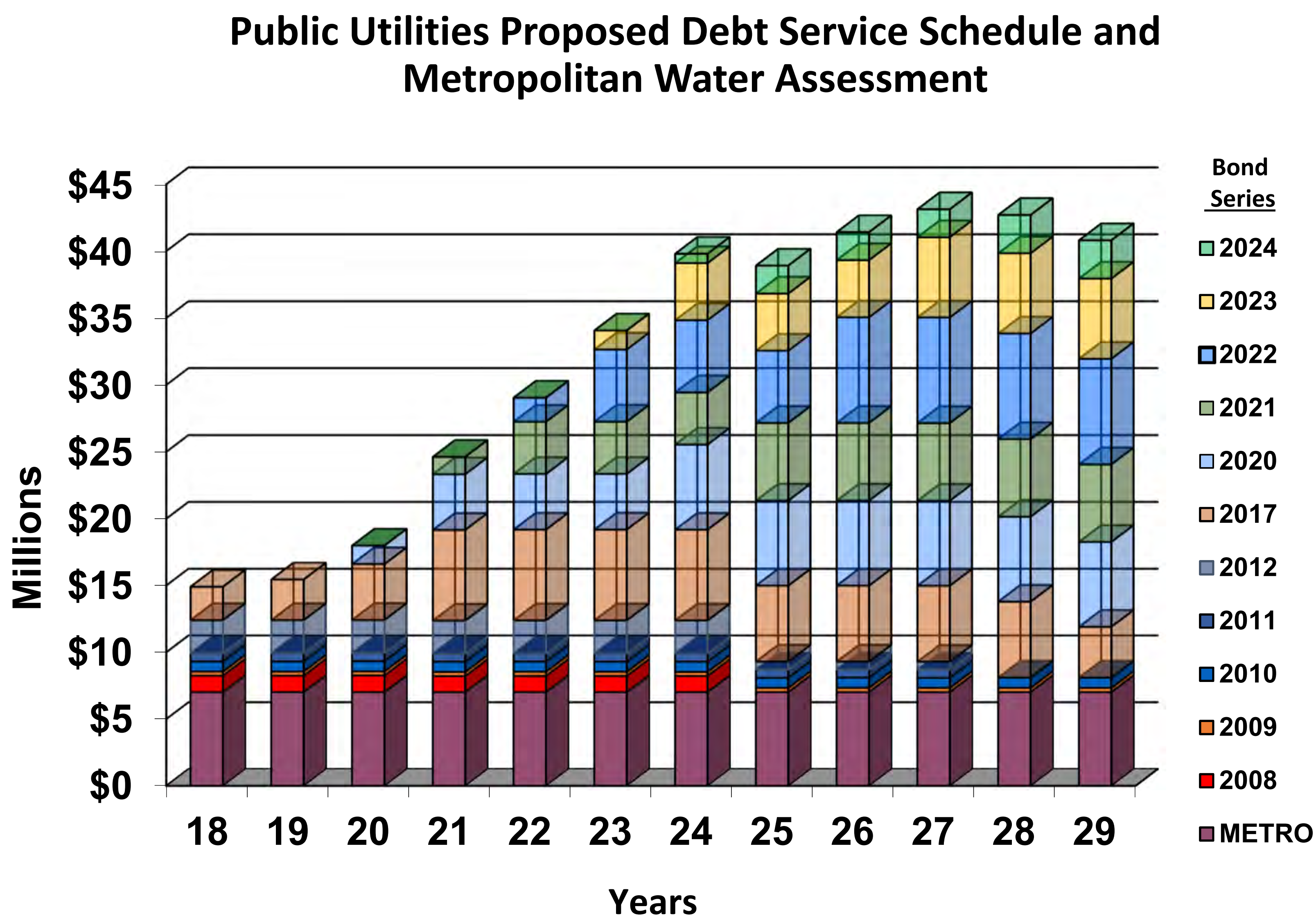

Stormwater Utility Operating Costs
Millions
$9
$8
$7
$6
$5
$4
$3
$2
$1
$0
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
Admistrative Service Fee
Payment for City Services
Payment in Lieu of Taxes
Street Sweeping
Operating & Maintenance Supply
Charges and Services
Personal Services

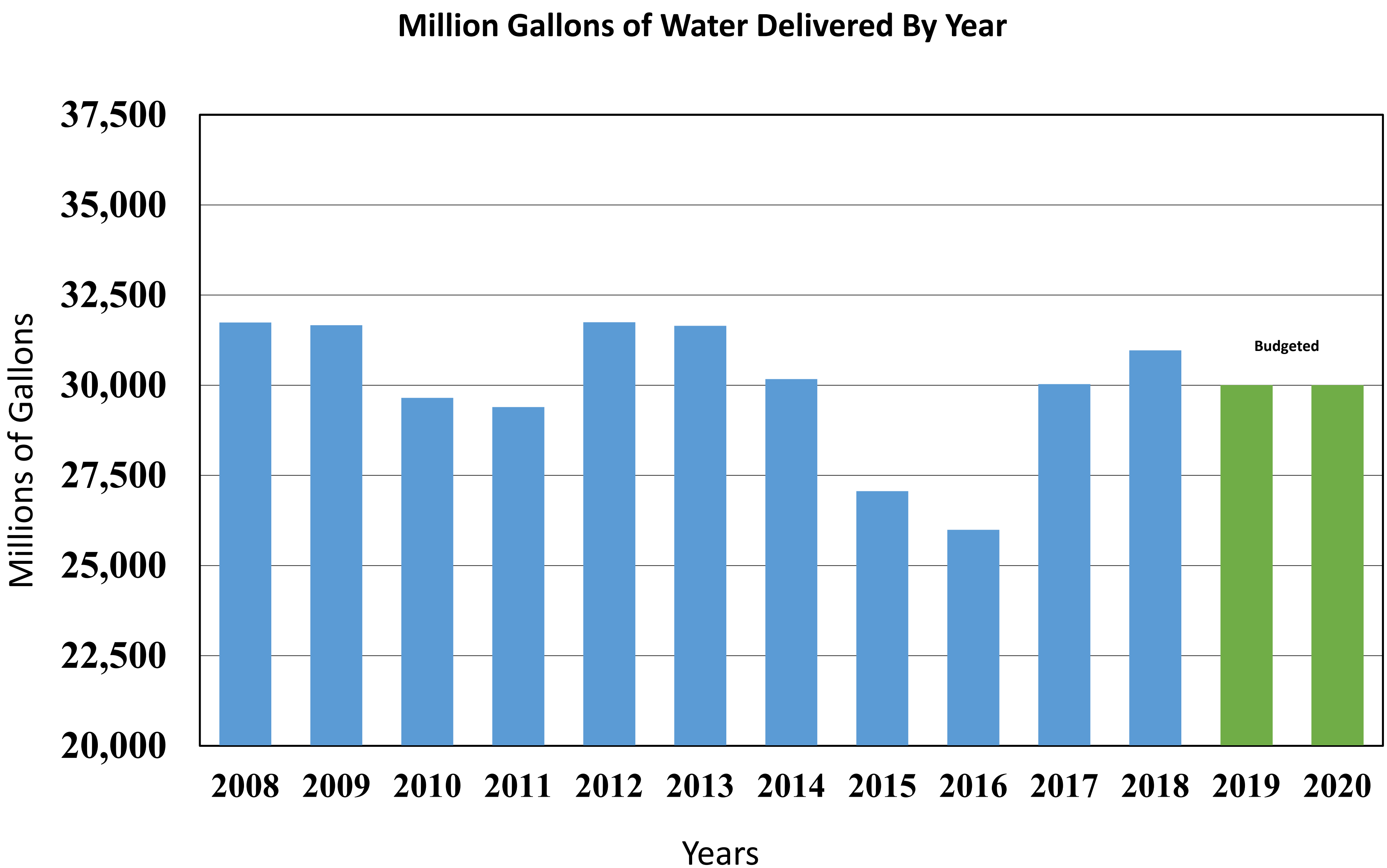
Street Lighting Utility Operating Costs

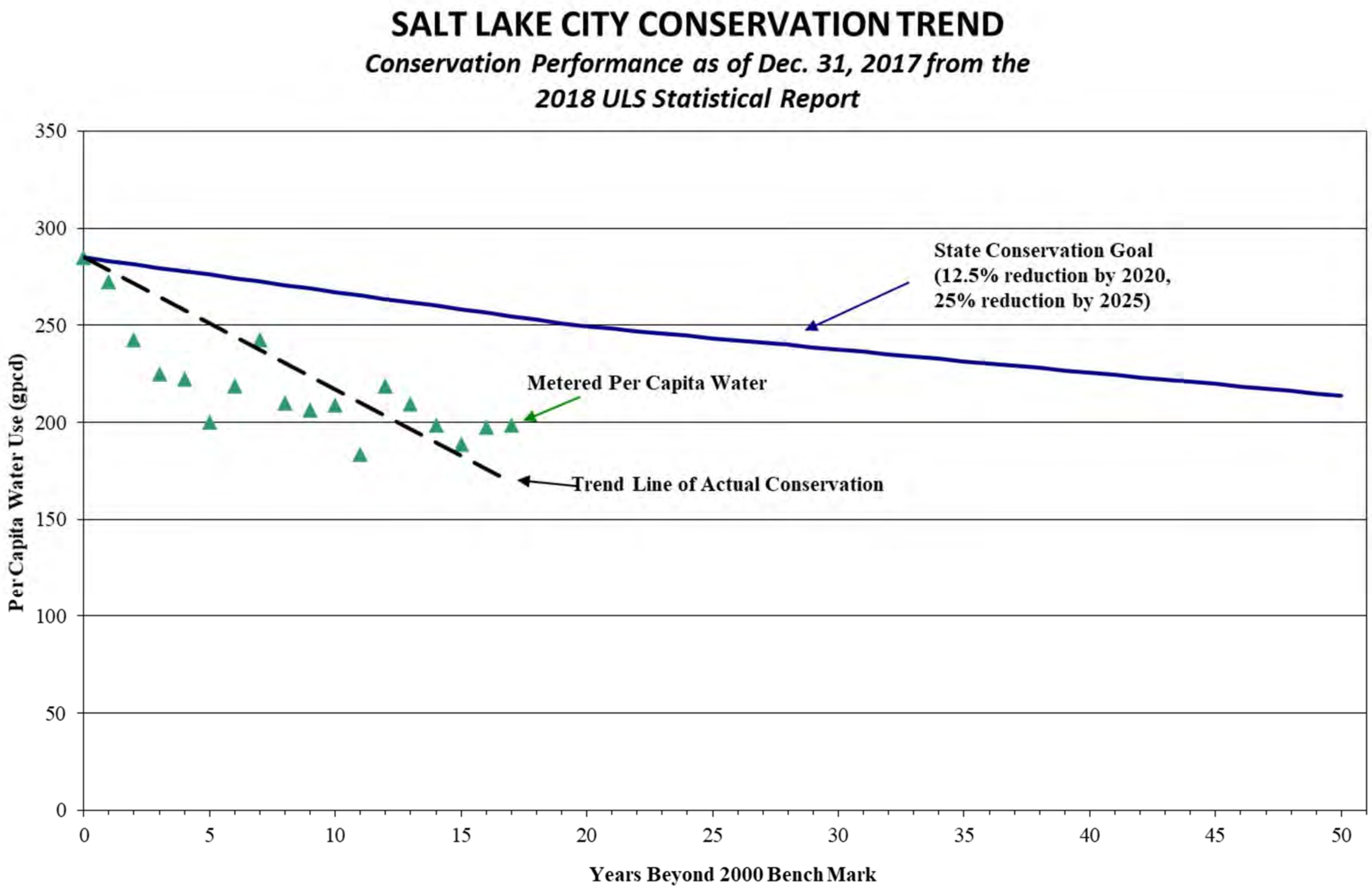


Public Utilities CIP Budget as a Percent of Department Requested Budget




Public Utilities Proposed Debt Service Schedule and
Metropolitan Water Assessment
$45
$40
$35
$30
$25
$20
$15
$10
$5
$0
Millions
18
19
20
21
22
23
24
25
26
27
28
29
Years
Bond Series
2024
2023
2022
2021
2020
2017
2012
2011
2010
2009
2008
METRO

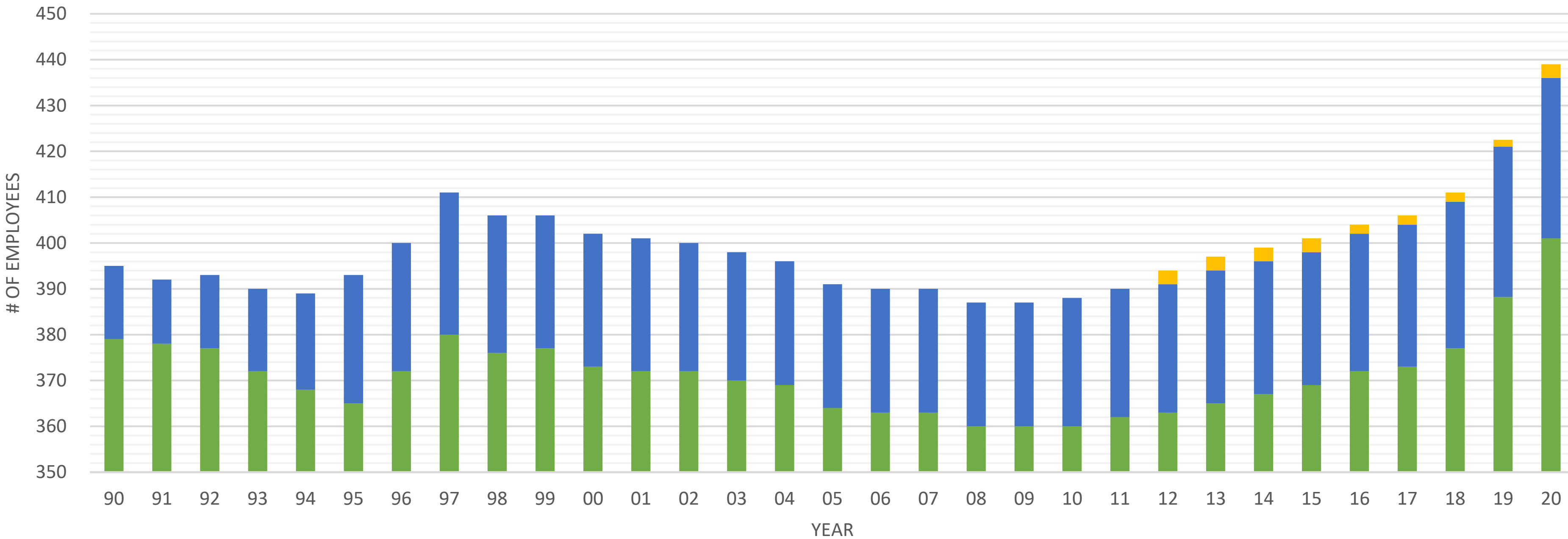

Million Gallons of Water Delivered By Year
37,500
35,000
32,500
30,000
27,500
25,000
22,500
20,000
Millions of Gallons
Budgeted
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
Years


SALT LAKE CITY CONSERVATION TREND
Conservation Performance as of Dec. 31, 2017 from the
2018 ULS Statistical Report
State Conservation Goal
(12.5% reduction by 2020,
25% reduction by 2025)
Metered Per Capita Water
Trend Line of Actual Conservation
Per Capita Water Use (gpcd)
Years Beyond 2000 Bench Mark
0
50
100
150
200
250
300
350
5
10
15
20
25
30
35
40
45
50

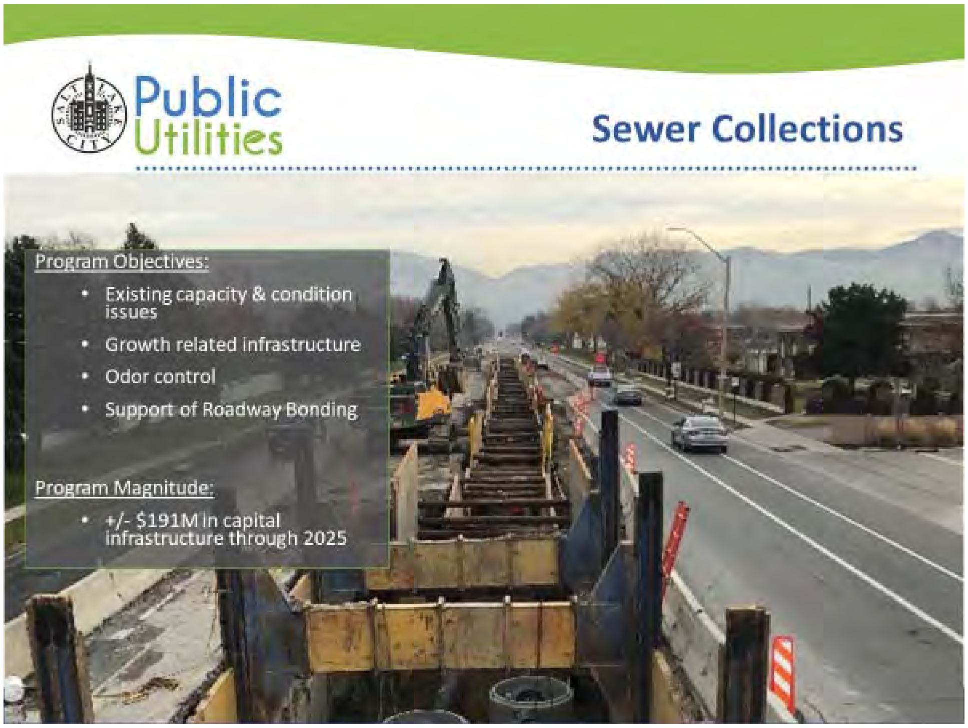
Proposed Personnel Adjustments FY 2019/2020

	TOTAL	WATER	SEWER	STORM WATER	STREET LIGHTING
Prior FY Ending FTE Balances by Fund	422.50	272.77	115.43	32.80	1.50
NEW POSITIONS REQUESTED FOR FY 19/20					
1) RECORDS TECHNICIAN	1.00	0.80	0.10	0.10	
2) COMMUNITY & ENGAGEMENT COORD	1.00	0.50	0.40	0.10	
3) SUSTAINABILITY PROGRAM MANAGER	1.00	1.00			
4) GIS LEAK DETECTOR SYSTEM TECH II UNON	1.00	0.50	0.30	0.20	
5) OFFICE TECHNICIAN II	1.00		1.00		
6) PRETREATMENT INSPECTOR/PERMIT WRITER	1.00		1.00		
7) PRETREATMENT SENIOR SAMPLER/INSPECTOR	1.00		1.00		
8) FOG/SEWER RATE PROGRAM SUPERVISOR	1.00		1.00		
9) MAINTENANCE ELECTRICIAN IV	1.00	1.00			
10) ENGINEERING TECH I	1.00				1.00
11) ENGINEERING TECH II	2.00	1.00	0.50	0.50	
12) ENGINEERING TECH III	1.00	0.50	0.25	0.25	
13) ENGINEER II	1.00	0.50	0.25	0.25	
14) ENGINEER III	2.00	1.00	0.50	0.50	
Total Increase of 16 FTE's for Public Utilities Dept.	438.50	279.57	121.73	34.70	2.50
Two Seasonal Watershed Workers	1.00	1.00			
TOTAL FTE'S	439.50	280.57	121.73	34.70	2.50
CHANGES TO FTE DUE TO REORGANIZATION:		1.65	-1.10	-0.55	0.00
Agency Totals for FY 2019/2020	439.50	282.22	120.63	34.15	2.50

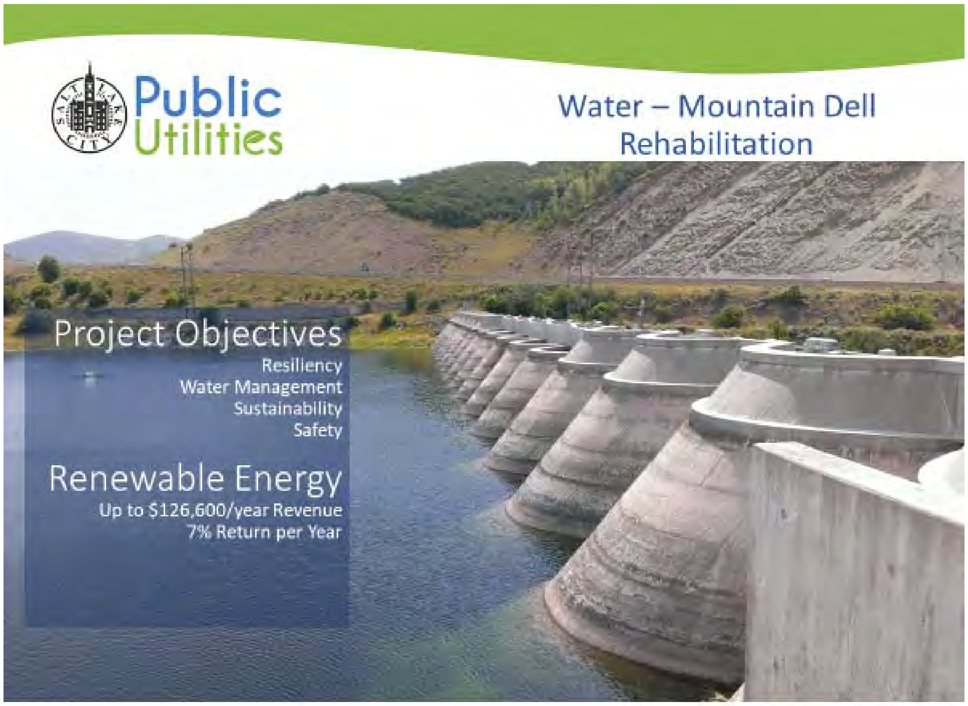
Public Utilities Number of Employees By Fund By Fiscal Year

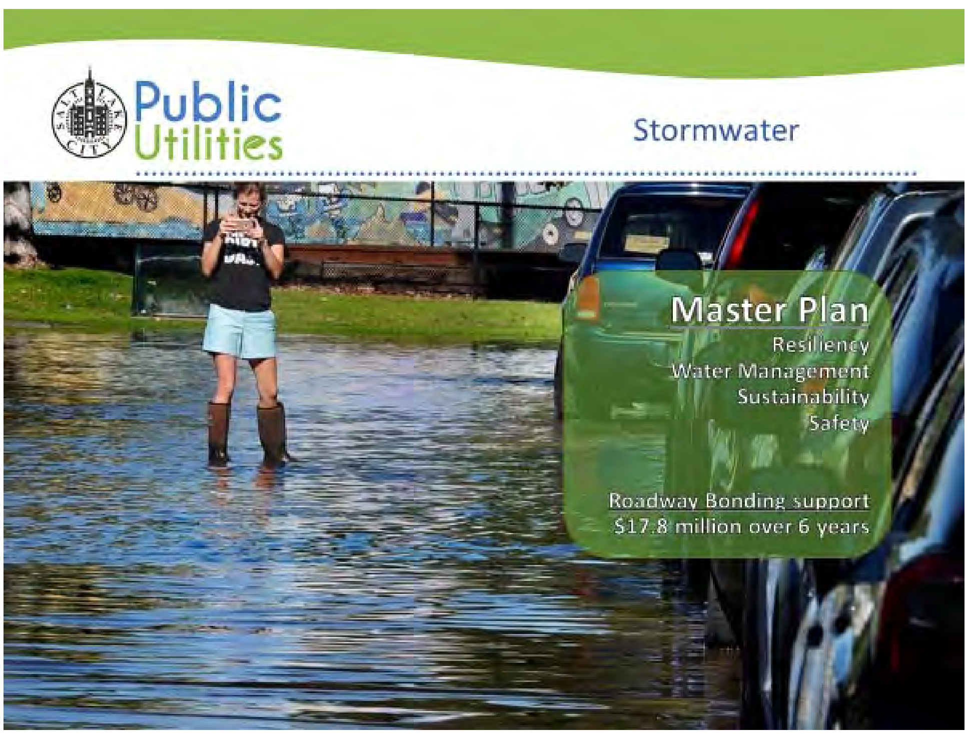


Year	90	91	92	93	94	95	96	97	98	99	00	01	02	03	04	05	06	07	08	09	10	11	12	13	14	15	16	17	18	19	20
Water & Sewer	379	378	377	372	368	365	372	380	376	377	373	372	372	370	369	364	363	363	360	360	360	362	363	365	367	369	372	373	377	388	401
Storm Water	16	14	16	18	21	28	28	31	30	29	29	29	28	28	27	27	27	27	27	27	28	28	28	29	29	29	30	31	32	33	35
Street Lighting																							3	3	3	3	2	2	2	2	3
# of Water Connections	84,098	84,526	85,921	86,360	86,665	87,233	85,514	89,191	90,393	89,776	80,218	90,766	91,283	81,751	92,955	92,344	90,748	90,912	90,920	90,976	90,958	90,624	90,251	90,349	90,435	90,451	91,467	91,545	91,802	???	???


Public
Utilities
Sewer Collections
Program Objectives:
• Existing capacity & condition issues
• Growth related infrastructure
• Odor control
• Support of Roadway Bonding
Program Magnitude:
• +/- $191M in capital infrastructure through 2025


Public
Utilities
Water – Capital Program
• East West Aqueduct Phase I ($10.0 million)
• Treatment Plant rehabilitation ($8.0 million)
• Road way bond support $9.65 million FY 20 (~$27.54 million over 6 years)
• Total Water Main Replacements ($23 million)


Public Utilities
Water – Mountain Dell Rehabilitation
Project Objectives
Resiliency
Water Management
Sustainability
Safety
Renewable Energy
Up to $126,600/year Revenue
7% Return per Year


Public Utilities
Stormwater
Master Plan
Resiliency
Water Management
Sustainability
Safety
Roadway Bonding support
$17.8 million over 6 years

JACQUELINE M. BISKUPSKI
Mayor

**DEPARTMENT OF
PUBLIC UTILITIES**

CITY COUNCIL TRANSMITTAL

Patrick W Leary
Patrick Leary, Chief of Staff

Date Received: 4/4/2019
Date sent to Council: 4/9/2019

TO: Salt Lake City Council
Charlie Luke, Chair

DATE: April 4, 2019

FROM: Laura Briefer, MPA
Director, Department of Public Utilities

SUBJECT: Request for a City Council resolution supporting the pursuit of the Water Reclamation Facility reconstruction as required to comply with Utah Administrative Code R317-1-3-3 and Utah Department of Environmental Quality Permit Requirements

STAFF CONTACTS: Jesse Stewart, Deputy Director, jesse.stewart@slcgov.com; Jason Brown, PE, Chief Engineer, jason.brown@slcgov.com; Lisa Tarufelli, Finance Administrator, lisa.tarufelli@slcgov.com

Laura Briefer, Jesse Stewart, Jason Brown, and Lisa Tarufelli will address the Council on this resolution.

DOCUMENT TYPE: Resolution (Exhibit A)

RECOMMENDATION: Approve a resolution supporting the pursuit of the reconstruction of the Water Reclamation Facility, particularly the implementation of biological phosphorus removal technology to meet requirements of Utah Administrative Code R317-1-3-3. It is also required that the adopted resolution include an approximate budget for the construction of the selected technology for conformance with the approved variance requirements.

BUDGET IMPACT:
The reconstruction of the Water Reclamation Facility (WRF) has been in the Public Utilities' long term plan and the projected costs have been projected in the Department's longer term budget planning since at least in 2015. At this time, the total estimated costs for design and construction of the new WRF is $528,130,000 (Exhibit B). The Department has worked with the Administration, Council, and the Public Utility Advisory Committee over the last several years to develop a long term financing and rate strategy. Public Utilities' goal of the financing strategy is to minimize the impact to the community, and balancing the financing, infrastructure, and regulatory requirements of the new WRF.

The costs for the WRF will be covered with a combination of rate increases, revenue bonds, and possibly longer term loans through state and federal programs. As such, Public Utilities is providing two

representative financing scenarios for the project, one using traditional revenue bonds, and the other using a federal loan for 49% of the project using under the federal Water Infrastructure Finance and Innovation Act (WIFIA). The scenarios, presented in **Exhibit C**, are presented in the context of the Sewer Utility's overall long term budget and cash flow planning in order to provide context to the budgetary requirement of the resolution.

Public Utilities plans to apply for a WIFIA loan for this project and believes this project would be competitive in the loan process (see WIFIA fact sheet, **Exhibit D**). We are also investigating state loans. Securing a loan under the federal WIFIA or state water infrastructure lending programs would mitigate some of the near-term impacts to ratepayers. In addition, the WIFIA loan program provides for a longer term (35 year) payback, which would distribute costs of the project more fairly across the generations that will benefit from the new WRF. The WIFIA and state loans require Buy America and federal wages, which may increase the cost of the project. Any additional costs can also be mitigated by the interest rates and longer payback terms.

Success in a WIFIA or state loan process is not guaranteed, in which case revenue bonding would be required. Therefore, Public Utilities is providing budgetary information for revenue bonding and federal/state loan programs.

BACKGROUND/DISCUSSION:
The Utah Department of Environmental Quality (UDEQ) adopted a new rule that went into effect on January 1, 2016 (R317-3-3), limiting the amount of phosphorus permitted to be discharged by wastewater treatment plants into State water bodies. Public Utilities was fully engaged with the rule making process and provided numerous comments and concerns outlining the impact to Salt Lake City and sewer rate payers. The new rule specifies compliance by January 1, 2020; however, the rule also allows for the Director of the UDEQ Water Quality Division to permit a variance to the compliance date if due diligence is made towards meeting the requirements of the rule.

Due to numerous issues associated with meeting the January 1, 2020 compliance date, including the age of the existing WRF, construction schedule, and procurement of funding, Public Utilities requested a variance on March 26, 2018. Conditional approval from UDEQ was received on May 29, 2018 to extend the compliance date to January 1st 2025. One of the conditions of the variance states that the Public Utilities Department must submit, no later than July 1, 2019 "*A City Council resolution supporting the pursuit of the facility upgrade to the selected biological phosphorus removal technology. The resolution shall include the approximate budget for the facility upgrade.*" **Exhibit E** provides all relevant regulatory correspondence to date.

It should be noted that over the last several years, Public Utilities evaluated numerous alternatives of meeting the new phosphorus rule that included alternatives to retrofit the existing WRF. Due to the age and condition of the existing WRF, it was determined that retrofitting the 55-year old WRF was not physically or economically feasible. It was also determined that the existing WRF has met its useful life, and needs to be reconstructed. For example, the existing WRF does not meet current seismic standards, and is vulnerable to disruption during extreme flood events. Engineering reports documenting these analyses are available to review upon request. Public Utilities can also present a summary of these studies if needed.

Public Utilities is currently designing the new WRF. The design and construction costs have been planned within Public Utilities' budgets starting in fiscal year 2018, and through 2025. This includes bond revenue

and design costs in the proposed FY 2020 budget. Currently, the estimated cost for construction of the new WRF is $528,130,000. This cost may change as engineering designs are completed, and are subject to evolving regional construction costs.

The construction is phased over seven years with the objective of meeting the rule by 2024, one year ahead of the regulatory compliance requirement. The 2024 objective is to allow for full commissioning of the new WRF to ensure the plant and all of its operational components will be in compliance by the 2025 deadline.

PUBLIC PROCESS: Public Utilities has engaged the public regarding the need for the new WRF throughout the last few years. Public Utilities has engaged the public regarding rate increases associated with financing the WRF. Examples of public engagement include community council meetings, periodic updates during City Council work sessions (particularly during annual budget discussions), media engagement, and postcard mailings. Public Utilities is continuing to engage the public, and has retained the public engagement firm, Wilkinson Ferrari, to assist. We continue to provide updates to community councils, and will be holding public open houses starting April 2019. Because of the duration of the project, Public Utilities' engagement will be ongoing and iterative.

EXHIBITS:

A. Council Resolution Supporting the Reconstruction of the Salt Lake City Water Reclamation Facility

B. Engineering Estimated Cost for new WRF and Site Plan

C. Estimated Design and Construction costs and rate scenarios for new WRF from 2019-2025, as a component of overall Public Utilities Sewer Planning Budget
   i. Scenario 1 – Revenue Bonds and Rate Increases
   ii. Scenario 2 – Federal Water Infrastructure Finance Improvement Act (WIFIA) Loan and Rate Increases

D. WIFIA Fact Sheet

E. Official correspondence between Salt Lake City Department of Public Utilities and Utah Department of Environmental Quality establishing a permit variance for Technology-Based Phosphorus Effluent Limits, dated November 6, 2017 through March 21, 2019

Exhibit A

Council Resolution Supporting the Reconstruction of the Salt Lake City Water Reclamation Facility

RESOLUTION NO. ________ OF 2019

Supporting Water Reclamation Facility Upgrade

WHEREAS, the city's Public Utilities Department operates its Water Reclamation Facility (WRF) that treats approximately 35 million gallons of wastewater per day and the Department has been planning to upgrade and replace the WRF since 2015. The city operates the WRF pursuant to its State issued UPDES Discharge Permit No. UT0021725.

WHEREAS, the Utah Department of Environmental Quality (UDEQ) adopted a new rule that went into effect on January 1, 2016 (R317-3-3), limiting the amount of phosphorus permitted to be discharged by wastewater treatment plants into State water bodies. The new rule specifies compliance by January 1, 2020; however, the rule also allows for the Director of the UDEQ Water Quality Division to permit a variance to the compliance date if due diligence is made towards meeting the requirements of the rule;

WHEREAS, due to numerous issues associated with meeting the January 1, 2020 compliance date, including the age of the existing WRF, construction schedule, and procurement of funding, the Public Utilities Department requested a variance on March 26, 2018, to extend the compliance deadline. Conditional approval from UDEQ was received on May 29, 2018 to extend the compliance deadline to January 1, 2025;

WHEREAS, the Public Utilities Department is currently designing the new WRF. The design and construction costs have been planned within Public Utilities' budgets starting in fiscal year 2018, and through 2025. This includes bond revenue and design costs in the proposed FY 2020 budget. Currently, the estimated cost for construction of the new WRF is $528,130,000, with the construction to be phased over seven years with the objective of meeting the rule by 2024, one year ahead of the regulatory compliance deadline;

WHEREAS, UDEQ's approval of the variance requested by the Public Utilities Department includes certain conditions for the extension of time for compliance under Rule 317-3-3. One condition is that the City Council adopt a resolution supporting the pursuit of the WRF upgrade to achieve the permitted biological phosphorus levels; and

WHEREAS, the Public Utilities Department has provided to the City Council with adequate information for it to make an informed decision supporting the upgrade of the WRF facility.

THEREFORE, BE IT RESOLVED by the City Council of Salt Lake City, Utah, as follows:

The City Council of Salt Lake City, Utah does hereby support the pursuit of the WRF upgrade to achieve the selected biological phosphorus levels in order to comply with the standards established for Salt Lake City under its UPDES Discharge Permit; such upgrade will require the approximate budget of $528,130,000, which is subject to future appropriations of the City Council.

Passed by the City Council of Salt Lake City, Utah, this _____ day of _______________, 2019.

SALT LAKE CITY COUNCIL

By: ________________________
CHAIRPERSON

ATTEST AND COUNTERSIGN:

____
CITY RECORDER

Approved as to form: ________________________
Salt Lake City Attorney's Office
E. Russell Vetter, Deputy City Attorney
Date: 4/2/19

HB_ATTY-#76249-v1-Resolution_Supporting_WRF_Upgrade_3-19

Exhibit B

Engineering Estimated Cost for new WRF
and Site Plan

PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	BUDGET YEAR 2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	
		NEW WATER RECLAMATION FACILITY								
524905271		NEW PLANT - CORE DESIGN/BUILD RECLAMATION FACILITY	1,750,000	10,250,000	5,000,000	3,500,000	2,000,000	400,000		
524905335		WRF MASTER PLAN IMPLEMENTATION - CAPITAL PROJECT SUPPORT	4,500,000	4,500,000	4,500,000	3,500,000	3,500,000	2,500,000	1,500,000	
		NEW PLANT - MECHANICAL DEWATERING (CONSTRUCTION)	33,500,000	440,000						
		NEW PLANT - BNR LIQUID STREAM (CONSTRUCTION)		41,020,000	155,430,000	120,360,000	15,960,000			
		NEW PLANT - SOLIDS HANDLING (CONSTRUCTION)					41,160,000	2,840,000		
		NEW PLANT - ADMIN OPS (CONSTRUCTION)		14,090,000	1,620,000					
		NEW PLANT - DEMOLITION (CONSTRUCTION)						5,000,000	1,500,000	
525400068	2017-2050	NEW PLANT - PROFESSIONAL DESIGN SERVICES	9,500,000	7,800,000	7,500,000	5,100,000	2,100,000	2,000,000	1,000,000	
524905339	2017-2051	NEW PLANT - CM/GC DESIGN SERVICES	3,000,000	2,500,000	1,000,000					
524905337	2017-2052	NEW PLANT - WATER RENEW PUBLIC OUTREACH	300,000	250,000	250,000	250,000	250,000	250,000	250,000	
524905340	2017-2054	NEW PLANT - PILOTING AND DEMONSTRATION TESTING	2,000,000	2,000,000						
		NEW PLANT - PROJECT DOCUMENTATION	150,000	60,000	60,000	60,000	60,000	60,000	60,000	
		TOTAL CAPITAL IMPROVEMENTS	54,700,000	82,910,000	175,360,000	132,770,000	65,030,000	13,050,000	4,310,000	**528,130,000**

Basis of Estimate

Nutrient Project – Pre-Design Estimate Salt Lake City Water Reclamation Facility

Prepared for
Salt Lake City, Utah
Department of Public Utilities

February 8, 2018

Contents

SLCWRF – Nutrient Pre-Design Estimate
Basis of Estimate

TABLE 0.1
Estimate Information
SLC-WRF – 15pct Design

Estimate Classification	Class 4
Requested By	Brewer, Mike/SLC
Estimated By	Bredehoeft, Pete/ATL, Sisneros, Steve/DEN
Estimator Phone	678-373-3235
Estimate Date	February 8, 2018

1. Purpose of Estimate

The purpose of this estimate of construction cost is to establish an Engineer's opinion of probable construction cost at the predesign level. Design costs, construction management costs and Owner costs are being handled at the program level.

2. General Project Description

The Salt Lake City Water Reclamation Facility (SLCWRF) is located at 1365 West 2300 North, Salt Lake City, Utah. The wastewater treatment facility owned and operated by the Salt Lake City Department of Public Utilities (SLCDPU). This construction estimate is for the phase 1 improvement (only), which replaces the existing facility and maintains the capacity of the plant to 56 MGD (AAF). The improvements include: influent pipeline, influent pump station (off-site) screening & grit removal (on-site), primary treatment, secondary treatment, chemical treatment & storage, UV disinfection, solids handling upgrades, including a new dewatering building to replace drying beds, thermal-alkaline hydrolysis, post aerobic digestion, thermal drying and new Combined Heat & Power facilities. Other improvements include new administration building, utility water pump station, primary electrical services and distribution, and standby power systems, and improvements to the natural wetland treatment system.

3. Overall Costs

The following is a summary breakdown of the construction costs.

Accuracy Range - High		**Accuracy Range - Low**
+25%	**Construction Cost without Escalation**	**-20%**
$482,467,000	$ 385,973,000	**$ 308,779,000**
	Construction Cost with Escalation - 5.32% (Buy-out)	
$508,133,000	$ 406,506,000	**$ 325,205,000**

This cost estimate has been prepared for guidance in project evaluation and implementation from the information available at the time of the estimate. The final costs of the project will depend on actual labor and material costs, competitive market conditions, final project costs, implementation schedule and other variable factors. As a result, the final project costs will vary from the estimate presented herein. Because of this, project feasibility and funding needs must be carefully reviewed prior to making specific financial decisions to help ensure proper project evaluation and adequate funding.

4. Scope of Work

This project consists of the following areas of improvements or facilities:

- Contractor – Startup & Testing
- Sitework – including 15' of imported fill for new facilities – Phase 1 Only
- Yard Piping – 28,171' LF or 5.3 miles
- Bypass Pumping, Connections and Tie-ins – Allowance
- Demolition of Existing Drying Beds – 26 acres
- Demolition of Building and Structure – Phase 1
- Demolition of Building and Structures – Bid Items (Phase 2)
- Existing Electrical Upgrades – Allowance
- Influent Pipeline – 3 Runs x 54" Dia – 4,300 LF
- Influent Pump Station & Course Screening – Offsite
- Influent Pump Station Odor Control Pad - Offsite
- Influent Connection Junction Boxes - Offsite
- Influent Flow Meter Vault
- Headworks Building – Onsite
- Headworks Odor Control Pad
- Grit Basin Facility
- Primary Influent Splitter Box
- Primary Clarifiers – 185' Dia – 4 EA
- Primary Effluent Splitter Box
- Primary Sludge Pump Station
- Primary Scum Pump Station
- Bioreactor Splitter Box
- Bioreactor Basin
- Secondary Clarifiers – 210' Dia – 4 EA
- Secondary Scum Pump Station
- Return Activated Sludge Pump Station
- Return Activated Sludge Splitter Box
- Blower Building – 19,46 SF
- Chemical Building – 5,714 SF
- UV Disinfection Building - Reto-fit of Existing Aeration Basins.
- Combined Heat and Power (CHP) Building – 3,800 SF
- Administration Building – 2-Story - 10,000 SF
- Operations Building – 20,000 SF
- Post Aerobic Digestion Tank
- Post Aerobic Diegestion Mechanical Building – 8,236 SF
- Dewatering Building – 2-Story – 12,440 SF
- Dryer Building – 12,136 SF
- Utility Water Pump Station – Reto-fit of Existing Aeration Basins
- Plant Drain Pump Station

- Effluent Parshall Flume – Flow Meter
- Plant Generators – Outdoor Units – 1.5MW – 2 EA – At IPS
- Plant Generators – Outdoor Units – 12.5MW – 4 EA – At WRF

5. Markups

These markups are based upon general assumptions about how the project will be contracted. Actual markup percentages may vary from those shown here, and are the responsibility of the bidding contractor.

TABLE 5.1
General Contractor Markups
Project Name

Contractor General Conditions	8.00%
Sales Tax on Material – Salt Lake City	6.85%
Contractor Overhead Home Office	4.00%
Contractor Profit	6.00%
Bonds and Insurance	2.16%
Estimate Contingency	10.00%
Escalation Rate – Based upon Contractor Buyout – 4 Months	5.32%

6. Escalation Rate

This estimate includes Escalation with the assumption that construction NTP will start in March 2020 with the midpoint of construction being June 2022. It is assumed that there will be 50 months (4.2 years) of construction duration. The full escalation of the project equates to an escalation factor of 10.81%. However, the escalation included in the cost estimate is based upon a 4-month contractor buyout or locking in of major equipment purchases and securing of subcontractors. This buyout escalation equates to be an escalation factor of 5.32%. (See appendix for Escalation Analysis.) The buyout escalation factor amount was used in this estimate.

This estimate assumes the project is based upon a design, bid, build contracting approach with single contract award. Phasing of construction packages is unknown and will be determined at a later date. This estimate assumes the NTP for a designer will be April 1, 2018, with a 24 month design period. The bid and award period for the construction contract will be based upon the CM At Risk procurement and be concurrent with the Design.

This CH2M HILL escalation forecast is based upon economic data from Global Insight, Inc. and the United States Bureau of Labor Statistics.

7. Estimate Classification

This cost estimate prepared is considered a feasibility or Class 4 estimate as defined by the Association for the Advancement of Cost Engineering International (AACE). It is considered accurate to +25% to -20%, based on a 15% pre-design deliverable.

8. Estimate Methodology

This cost estimate is considered a bottom rolled up type estimate with cost items and breakdown of Labor, Materials and Equipment. Process equipment quotations were obtained for the majority of major equipment. The estimate includes detailed takeoff and pricing for all divisions of work. The estimate may include allowance cost for plumbing

and HVAC. Other general allowances have been included in the estimate. Dollars per SF cost for the Administration and Operations buildings.

9. Cost Resources

The following is a list of the various cost resources used in the development of the cost estimate:

- CH2M HILL Historical Data
- R.S. Means
- Vendor Quotes on Equipment and Materials where appropriate
- Estimator Judgment

10. Labor Costs

The estimate has been adjusted for local area labor rates, based upon Davis Bacon rates for Salt Lake City, UT, 2017 rates.

Labor unit prices reflect a burdened rate, including: workers compensation, unemployment taxes, Fringe Benefits, and medical insurance.

11. Taxes

An 6.85% sales tax for Salt Lake City was added to all material costs within the estimate including process equipment. However, Certain pollution control facilities are exempt from sales tax "R865-19S-83. Pollution-Control Facilities Pursuant to Utah Code Ann. Section 59-12-104). An adjustment for tax exception has not been included in this estimate.

12. Major Assumptions

The estimate is based on the assumption the work will be done on a competitive bid basis and the contractor will have a reasonable amount of time to complete the work. All contractors are equal, with a reasonable project schedule, no overtime, constructed as under a single contract, no liquidated damages.

This estimate should be evaluated for market changes after 90 days of the issue date. It is assumed that much of the fabricated equipment will be shipped from the mainland USA.

Yard Piping

1. If a discrepancy on yard piping with facility exposed piping, the size shown on the yard piping will dictate. The facility drawing size will dictate on the exposed piping.

Grit Basin Facility

1. Influent Well Slab – Assumed 24" thick.
2. Cutthroat Flow Channel Slab – Assumed 18" thick.
3. Influent Flow Channels Slab – Assumed 18" thick.
4. Grit Basin Slab – Assumed 18" thick.

Primary Clarifiers

1. Base Slab – Assumed average of 16" thick.

Primary Sludge Effluent Splitter Box

1. Base Slab – Assumed 30" thick.

Primary Scum Pump Station

1. Pumps – Assumed 15hp

Secondary Scum Pump Station

1. Pumps – Assumed 15hp

Bioreactors

1. Base Slab – Assumed 36" thick.

Blower Building

1. Base Slab – Assumed 18" thick.

Secondary Clarifiers

1. Base Slab – Assumed 24" thick.

RAS/WAS Pump Station

1. Base Slab – Assumed 24" thick.
2. RAS Pumps – Assumed VFD is required and included in estimate.

Utility Water Pump Station

1. Non-Potable Water – Small Pumps – Assumed Vertical Turbine Pumps – 50hp/EA.

RAS Splitter Box

1. Base Slab – Assumed 30" thick.

Chemical Building

1. Base Slab – Assumed 18" thick

UV Disinfection Facility

1. Assumed new building is only over new channel space only, and extends out into new truck bay area.
2. Assumed new truck bay area base slab is 18" thick.

Post Aerobic Digestion

1. Base Slab – Assumed 24" thick

Post Aerobic Digestion Mechanical Building

1. Base Slab – Assumed 24" thick
2. Tank Wall – Assumed 24" thick

Dewatering Building

1. Base Slab – Assumed 24" thick.
2. Sludge Storage Pad – Assumed 24" thick with 4' high containment wall. Included an allowance for water collection of sludge water.

CHP Building

1. Base Slab in Engine Area – Assumed 36" thick, 12" in Electrical Room

Existing Electrical System Upgrades – Allowance

1. Existing Electrical System Upgrades – Assumed 6 men for 6 months and $1,500,000 material allowance.

Headworks Building

1. Lower Base Slab – Assumed 36" thick.
2. Perimeter Walls – Assumed 24" thick.
3. Building – Assumed CMU block with Double Tee Roof. Assumed 32' overall height.
4. Assumed 4 Ton Bridge Crane.

5. Special Coatings – Assumed T-Loc liner for all channels.
6. Footprint 144' by 60'
7. The building will sit on 15' of compacted fill at the new WRF
8. 4 bar screens
9. One extra spot for a 5th screen at final build out
10. 2 compactors
11. 2 loadout bays

Effluent Parshall Flume

1. Assumed new open channel, 200' Long x 5' wide x 8' high walls. Cast in place construction is assumed.
2. Flow Meter insert for Parshall Flume
3. Assumed grating over top of open channel.
4. Assumed a concrete 6' wide cantilevered deck x 200' long with stairs and handrail

Wetlands – Rock Weir and Spillway

1. The rock weir and spillway is constructed of 12"-18" rip-rap material, with filter fabric.
2. The approximate dimensions are 100' long x 17' wide x an average of 4' high.
3. Grading of Wetlands is based upon drawing C-14-100

Plant Drain Pump Station

1. Assumed plant drain system is the same as the Primary and Secondary scum pump station.

Electrical

1. Have used the Electrical One-line Drawings as reference for major electrical gear and MCC's.
2. Electrical Gear as shown on electrical one-lines costs are based on estimator judgment and previous project cost.
3. Generators cost include belly fuel tank and sound enclosure placed on slab exposed to environment.
4. Generator Switch Gear, includes costs for weather-proof enclosure to be located on slab exposed to environment.
5. Electrical one-lines for power distribution requirements, made assumptions and best judgment for general routing.
6. Duct-bank cost allowances based on estimator judgement and past projects of similar design.
7. Over-head Power cost allowances based on estimator judgement.
8. Utility Transformers carried in estimate as depicted on Electrical One-lines (Utility power feed and source to be supplied by Utility Company).
9. General electrical requirements, such building electrical, HVAC, etc. cost is accounted for in the Facility Electrical Allowance.

Instrumentation and Control (I & C)

1. Contractor Programming – Included cost for contractor to provide programming of installed equipment only.
2. I & C - Is estimated based on historical standard percentages used for typical facilities and processes.

Influent Pipeline

1. Pipeline – 54" Dia x 3 Run x 4,300' LF – Assumed HDPE pipe, glass line.
2. Pipeline – assumed pipeline is at mimimum buried depth.
3. Pipeline – assumed 10% for sheeting and shoring is required – 15' Embed.
4. Pipeline – assumed 20% requires well point dewatering for 4 months.
5. Pipeline – assumed no pipeline crossings.
6. Pipeline – assumed no pavement pavement restoration or improvements.
7. Pipeline – assumed hydro seeding along route, 4,300 LF x 50'wide.

Influent Pipeline – Connection Boxes

1. 1 interceptor box for pipelines at 15' by 28' by 30' deep
2. 1 interceptor box for pipelines at 14' by 12' by 30' deep
3. 1 junction box for pipelines at 14' by 34' by 30' deep
4. 280 feet of 48 inch dia. FRPMP pipeline @ 30 feet deep
5. 350 feet of 84 inch dia. FRPMP pipeline @ 30 feet deep
6. 70 feet of 96 inch dia. FRPMP pipeline @ 30 feet deep

Influent Pump Station

1. Existing plant footprint approx. 7,500 ft. sq.
2. Use 9,750 ft. sq. – 30% larger
3. 30 feet deep
4. Existing pumps 4 ea. @ 350 Horsepower
5. New pump use 4 ea. @ 770 Horsepower – approx. 30% larger
6. Space for 1 additional pump at final build out
7. New pump station will have an odor control facility
8. No additional pump station will be required at the new WRF

Sitework

1. Demolition of Existing Roadway Pavement – assumed 6" overall depth.
2. New Asphalt Pavement – Assumed 8" base stone course, 3" asphalt base course, 2" asphalt wearing course.
3. Sidewalks – assumed 5% of asphalt pavement area.
4. Stormwater System – Allowance – 8,000 LF of 36" – 18" RCP Pipe and 40 catch basins.
5. Gas Utilities – Allowance – 5,000 LF of 2" Dia pipe.
6. Dump Charge – Assume County Landfill will be used. This could be a potential large project savings if the City could negotiate waving or a lower disposal fee charge.
7. Imported Fill – Overall site has 15' of imported material. Assumed clean fill, imported from 10 miles round trip at a cost of $9.00/CY. Imported fill is only in new facilities area, located at the demolished sludge drying beds and phase 1 work area only.
8. Hauling – assumed 10 miles round trip for hauling of offsite soil waste material.
9. Disposal or Dump Fee is based upon Salt Lake County Landfill prices:
    a. Construction Debris - $31.35/TON
    b. Asphalt/Concrete $5.00/Ton
    c. Soil Disposal - $5.35/Ton
    d. Assumed contractor will sort and separate concrete and rebar to minimize cost.
10. Dewatering – Since overall site has 15' of fill material – assumed well point dewatering is required for any facility deeper than 12' deep.
11. Shoring – Assumed facility depths over 12' deep will require sheeting and shoring to keep out dewatering and for working space for construction of that facility.
12. Imported Fill:
    a. Imported 15' – Clean Fill – 880,000 CY
    b. Scarify, Compaction, Rough and Final Grading – 153,000 SY
13. Seeding Construction Area – 860,000 SF
14. Asphalt Pavement – 375,000 SF

Demolition

The demolition of existing sludge drying beds and various facilities, includes the following assumptions:

1. Asphalt Pavement demolition – 325,000 SF
2. Sludge Drying Beds:

    a. Assumed SLC staff will removal and clean out all existing sludge and sludge water prior to contractor demolishing the sludge drying beds.
    b. Assumed 6" of concrete will be demolished and hauled off site, 21,200 CY.
    c. Assumed 1.5' of berm material and contaminated sludge material, 63,400 CY will be hauled off site.
3. Aeration Basin – 10 crew days to demolish.
4. Tower Structure – 10 crew days to demolish.
5. Bid Options:
    a. Blower Building – 7 crew days to demolish
    b. Chemical Building – 5 crew days to demolish
    c. Chlorine Contact Basin – 10 crew days to demolish
    d. Primary Clarifiers 140' dia – 4 EA – 20 crew days to demolish
    e. Secondary Clarifiers 140' dia – 4 EA – 20 crew days to demolish
    f. Trickling Filters 190' Dia – 4 EA – 20 crew days to demolish

Startup and Testing

1. Assumed contractor startup and testing period of 4 months.

Special Coatings

1. T-Loc Liner is included for the base slab, walls, channels and upper elevated slab on the following facilities:
    a. Influent pump station.
    b. Influent junction boxes.
    c. Headworks.
    d. Grit basin facility.
2. Special Coatings – Epoxy Flooring is included in the following facilities:
    a. Blower building.
    b. Chemical building.
    c. CHP building
    d. Post aerobic digestion mechanical building.
    e. Dewatering building.
    f. Dryer building.

Labor Availability

1. Assumed adequate availability of construction labor, across all trades. This should be evaluated as the design progresses for current market conditions. The airport expansion project and prison expansion project may affect labor resources on the WRF project. No adjustment to the estimate has been made at this time.

Contracting Strategy

1. The Construction Contact will be a CM At Risk contract, with the Guaranteed Construction amount developed at a 90 percent design level.
2. The phasing of construction packages has not been flushed out at the time of the estimate. However, it is anticipated that the Dewatering Building maybe the first contract construction package. The second construction package could be the Headworks, Grit Screening, Influent Pump Station, Influent Junction Boxes, Influent Meter Vault and Demolition of Existing Drying Beds.
3. The final construction phasing schedule would be developed at the GMP development.

13. Key Project Quantities

The following are overall plant wide key project quantities, summary information:

Facility Name	Concrete CY	Earthwork Excavation CY	Excavation Depth Ft	Sheeting and Shoring SF	Dewatering MO	Buried Pipe LF	Process Pipe LF
Sitework - Imported 15' Clean Fill		880,000					
Yard Piping		80,505	9	147,200	9	28,171	
Influent Pipeline - Twin 60" Dia - 3,600 LF		52,799	12	21,600	2	7,200	
Influent Pump Station & Junction Boxes - Off-site	8,193		32	64,973	33	875	880
Influent Meter Vault	309	1,900	34	9,900	5		
Influent Pump Station Odor Control Pad - Off-site	217	575	2				50
Headworks - On-Site	2,503	15,400	37	24,696	12	175	700
Grit Basin Facility - On-Site	2,111	10,900	13	18,414	10		600
Headworks - Odor Control Pad - On-site	217	575	2				300
Primary Effluent Splitter Box	391	2,500	17	6,160	4		
Primary Influent Splitter Box	391	2,500	17	6,160	4		
Bioreactor Splitter Box	391	2,500	17	6,160	4		
Primary Sludge Pump Station	308	3,250	16	5,796	4		584
Primary Clarifiers - 4 EA	10,920	63,500	12			460	
Primary Scum Pump Station		225	9			20	50
Secondary Scum Pump Station		225	9			20	50
Plant Drain Pump Station		225	9			20	50
Bioreactors	38,789	289,800	31	79,376	18		6,752
Secondary Clarifiers - 4 EA	17,607	82,100	12			1,200	
Return Activated Sludge Pump Station	673	3,600	8				1,235
Return Activated Sludge Spitter Box	441	3,300	23	6,750	6		16
Blower Building	1,244	5,700	7				2,925
Chemical Building	623	2,800	9				1,200
UV Disinfection Facility	85						
Effluent Parshall Flume - Flow Meter	595	4,100	21	13,272	6		
CHP Building	406	2,200	8				800
Utility Water Pump Station	40						250
Post Aeration Digestion Tank	1,587	13,900	32	15,523	6		
Post Aeration Digestion Mechanical Building	564	3,100	7				2,240
Dewatering Building	2,142	6,100	9			500	2,500
Dryer Building	2,888	6,600	10				1,000
Plant Generator - 6 EA	1,167	850	5				
OVERALL PLANT - TOTALS	**94,801**	**1,541,729**	**425**	**425,980**	**123**	**38,641**	**22,182**

14. Allowances

The estimate includes allowances for known work that is not sufficiently detailed at this time:

- Bypass pumping, tie-in connections and temporary facilities
- Yard Piping – site wide – Allowance for well point dewatering – 9 months.
- Miscellaneous metals allowances
- Interior painting allowance
- Toilet rooms allowance at Headworks
- Stormwater allowance
- Natural gas allowance
- Dryer exhaust system allowance
- Administration Building – 10,000 SF - $550/SF direct cost – Single story, includes office space, reception, conference rooms, training rooms, and break rooms.

- Operations Building – 20,000 SF - $250/SF direct cost – Single story, includes office space, conference rooms, training rooms, maintenance space, storage, operations room and operations laboratory.

15. Excluded Costs

The cost estimate excludes the following costs:

- Phase 2 improvements are not included in the construction cost estimate.
- Demolition of existing influent pump station is not included in this cost estimate.
- Demolition of existing screening facility is not included in this cost estimate.
- Demolition of existing CHP building is not included in this cost estimate.
- Demolition of existing administration building is not included in this cost estimate.
- Existing Sludge Ponds - Assumed SLC staff will removal and clean out all existing sludge and sludge water prior to contractor demolishing the sludge drying beds. Excluded this work.
- Replacement of any existing process equipment with new equipment is not included.
- Concrete or structural repair of existing structures are not included.
- Pile Foundations or Soil Treatment is not included in the cost estimate.
- Plantwide automation integration is excluded.
- Wetland improvement and mitigation items are excluded.
- Concrete Curb and Gutter is excluded.
- New security or chain-link fence is excluded.
- Open Space improvements are excluded.
- Stormwater ponds or bioretention ponds are excluded.
- Landscaping costs are excluded.
- Imported fill for phase 2 facilities is excluded.
- The cost for to incorporate "Envision" guidelines for incorporate principles for sustainable civil infrastructure have not been included in this cost estimate.
- Utility Power Source or feed into the plant has been excluded from this estimate.
- Labor shortage of resources is excluded.
- State Sale Tax Exemption has not been included in this estimate.
- Non-construction or soft costs for design, services during construction, land, legal and owner administration costs
- Material Adjustment allowances above and beyond what is included at the time of the cost estimate

16. Reference Documents

This cost estimate is based upon Water Works 15% Pre-Design Drawings and Design Report, dated August 2017.

N

SCALE IN FEET

KEYNOTES

1 WETLANDS
2 ADMINISTRATION BUILDING
3 EFFLUENT HEAT RECOVERY FACILITY
4 TERTIARY FILTRATION FACILITY
5 DISINFECTION FACILITY
6 EQUIPMENT STORAGE BUILDING
7 SECONDARY CLARIFICATION FACILITY
8 ADMINISTRATION BUILDING (EXISTING)
9 OUTFALL
10 BIOLOGICAL NUTRIENT REMOVAL FACILITY
11 OPERATIONS & MAINTENANCE BUILDING
12 WASTE ACTIVATED SLUDGE GRAVITY THICKENING FACILITY (EXISTING)
13 WASTE ACTIVATED SLUDGE MECHANICAL THICKENING FACILITY (EXISTING)
14 COMBINED HEAT & POWER FACILITY (EXISTING)
15 COUNTY PUMPS 1-4
16 SLUDGE STORAGE PAD
17 BLOWER BUILDING
18 PRIMARY CLARIFICATION FACILITY
19 THERMAL DRYING FACILITY
20 DEWATERING FACILITY
21 COMBINED HEAT & POWER FACILITY
22 DIGESTION FACILITY (EXISTING)
23 RESOURCE RECOVERY FACILITY
24 WEST MAINTENANCE (EXISTING)
25 HEADWORKS FACILITY
26 SEPTAGE RECEIVING STATION
27 INFLUENT PUMP STATION
28 BIOLOGICAL NUTRIENT REMOVAL TRAINING FACILITY
29 STAND-BY POWER
30 ELECTRICAL SUBSTATION
31 HAULED WASTE RECEIVING STATION
32 STOREHOUSE
33 CHEMICAL STORAGE FACILITY
34 CONSTRUCTION STAGING AREA

LEGEND

NON-PROCESS FACILITIES NEW / EXISTING

LIQUID STREAM FACILITIES NEW / EXISTING

SOLIDS STREAM FACILITIES NEW / EXISTING

FUTURE FACILITIES

KEY PLAN

SCALE: 1" = 100'

VERIFY SCALE
BAR IS ONE INCH ON ORIGINAL DRAWING

DESIGNED BY:
DRAWN BY:
CHECKED BY:
APPROVED BY:
DATE:
EWO NO:
ACCOUNT NO:

REVISIONS

SALT LAKE CITY DEPARTMENT OF PUBLIC UTILITIES
WATER RECLAMATION FACILITY UPGRADE

OVERALL SITE PLAN

PRELIMINARY
NOT FOR CONSTRUCTION

DRAWING No
XX-010-C102

SHEET ___ OF ___

Exhibit C

Estimated Design and Construction costs and rate scenarios for new WRF from 2019-2025, as a component of overall Public Utilities Sewer Planning Budget

i. Scenario 1 – Revenue Bonds and Rate Increases
ii. Scenario 2 – Federal Water Infrastructure Finance Improvement Act (WIFIA) Loan and Rate Increases

SEWER UTILITY
Planning Budget
FY20 Budget
and FY2020-2026 Forecast

+18%,20%,25%,25%,10%,10% Rate Increases
$0 in WIFIA Funds
$523M in Bonds,$55M,$107M,$187M,$138M,$69M,$17M
New Debt Pmts $109M FY 20-26
$528M New WRF in CIP

	ACTUAL YEAR 2017-2018	PROJECTED YEAR 2018-2019	BUDGET YEAR 2019-2020	BUDGET YEAR 2020-2021	BUDGET YEAR 2021-2022	BUDGET YEAR 2022-2023	BUDGET YEAR 2023-24	BUDGET YEAR 2024-25	BUDGET YEAR 2025-26
SEWER SALES	$33,620,751	$37,677,666	$44,460,000	$53,733,000	$67,642,000	$85,148,000	$94,317,000	$104,468,000	$115,705,000
OTHER INCOME	662,733	255,000	255,000	255,000	255,000	255,000	255,000	255,000	255,000
INTEREST INCOME	1,579,221	1,052,000	604,000	21,000	21,000	23,000	1,090,000	29,000	30,000
OPERATING INCOME	35,862,705	38,984,666	45,319,000	54,009,000	67,918,000	85,426,000	95,662,000	104,752,000	115,990,000
NEW PLANT O&M COSTS			0	0		(250,000)	(252,500)	(255,025)	(257,575)
OPERATING EXPENSES	(15,354,771)	(19,425,617)	(21,024,164)	(21,780,388)	(22,448,209)	(23,138,679)	(23,852,612)	(24,375,034)	(24,862,535)
NET INCOME EXCLUDING DEP.	20,507,934	19,559,049	24,294,836	32,228,612	45,469,791	62,037,321	71,556,888	80,121,941	90,869,890
IMPACT FEES	971,344	700,000	700,000	724,500	749,858	776,103	803,267	831,381	860,479
STATE LOAN (NWQ)	8,500,000								
SHORT TERM FINANCING PROCEEDS									
WIFIA LOAN									
NET BOND PROCEEDS	0		55,000,000	106,000,000	182,000,000	125,000,000	55,000,000		
ISSUE COSTS (PROCEEDS)			307,000	592,000	1,016,000	698,000	307,000	0	0
ISSUE COSTS (EXP)			(307,000)	(592,000)	(1,016,000)	(698,000)	(307,000)	0	0
OTHER CONTRIBUTIONS	978,525	2,020,000	2,020,000	2,020,000	720,000	520,000	520,000	520,000	520,000
CAPITAL OUTLAY	(847,714)	(1,302,569)	(8,694,000)	(823,000)	(823,000)	(823,000)	(823,000)	(823,000)	(823,000)
STATE LOAN DEBT REPAYMENT			(6,375,000)	(2,125,000)					
NEW DEBT SERVICE		0	(719,000)	(3,632,000)	(9,266,000)	(16,583,000)	(22,553,000)	(26,528,000)	(30,109,000)
DEBT SERVICE	(5,561,477)	(6,050,603)	(6,055,000)	(8,574,000)	(8,560,000)	(8,561,000)	(8,935,850)	(8,561,000)	(8,561,000)
OTHER INCOME & EXPENSE	4,040,678	(4,633,172)	35,877,000	93,590,500	164,820,858	100,329,103	24,011,417	(34,560,619)	(38,112,521)
NET FOR CAPITAL	24,548,612	14,925,877	60,171,836	125,819,112	210,290,649	162,366,424	95,568,305	45,561,322	52,757,369
CAPITAL IMPROVEMENTS	$ (33,243,806)	$ (60,892,051)	$ (98,370,500)	(125,728,000)	(210,160,000)	(162,630,000)	(94,660,000)	(45,480,000)	(30,321,000)
NEW WRF IN CIP			$ (54,700,000)	(82,910,000)	(175,360,000)	(132,770,000)	(65,030,000)	(13,050,000)	(4,310,000)
CASH INCREASE/(DECREASE)	(8,695,194)	(45,966,174)	(38,198,664)	91,112	130,649	(263,576)	908,305	81,322	22,436,369
		0							
BEGINING CASH BALANCE	94,916,245	86,221,051	40,254,877	2,056,213	2,147,325	2,277,974	2,014,398	2,922,703	3,004,025
CASH INCREASE/(DECREASE)	(8,695,194)	(45,966,174)	(38,198,664)	91,112	130,649	(263,576)	908,305	81,322	22,436,369
ENDING BALANCES	**86,221,051**	**40,254,877**	**2,056,213**	**$2,147,325**	**$2,277,974**	**$2,014,398**	**$2,922,703**	**$3,004,025**	**$25,440,394**
RESTRICTED/RESERVED	**(10,789,378)**								
AVAILABLE ENDING BALANCE	**$75,431,673**	**$40,254,877**	**$2,056,213**	**$2,147,325**	**$2,277,974**	**$2,014,398**	**$2,922,703**	**$3,004,025**	**$25,440,394**
RATE CHANGE	**30%**	**15%**	**18%**	**20%**	**25%**	**25%**	**10%**	**10%**	**10%**
Cash Reserve Ratio	**562%**	**207%**	**10%**	**10%**	**10%**	**9%**	**12%**	**12%**	**101%**
Debt Service Coverage	**3.69**	**3.23**	**1.85**	**2.25**	**2.55**	**2.47**	**2.27**	**2.28**	**2.35**
DEBT SERVICE % OF GROSS OPERATING REVENUE	16%	16%	15%	23%	26%	29%	33%	33%	33%
MONTHLY RESIDENTIAL UTILITY BILL AT 4 CCF	10.60	12.16	14.68	17.62	22.03	27.54	30.29	33.32	36.65
MONTHLY RESIDENTIAL UTILITY BILL AT 8 CCF	21.20	24.32	29.36	35.23	44.04	55.05	60.56	66.62	73.28

SEWER UTILITY
Planning Budget
FY20 Budget
and FY2020-2026 Forecast

+18%,18%,18%,15%,10%,10% Rate Increases
$259M in WIFIA Funds
$283M in Bonds,$55M,$39M,$97M,$65M $27M
New Debt Pmts $45M FY 20-26
$528M New WRF in CIP

	ACTUAL YEAR 2017-2018	PROJECTED YEAR 2018-2019	BUDGET YEAR 2019-2020	BUDGET YEAR 2020-2021	BUDGET YEAR 2021-2022	BUDGET YEAR 2022-2023	BUDGET YEAR 2023-24	BUDGET YEAR 2024-25	BUDGET YEAR 2025-26
SEWER SALES	$33,620,751	37,677,666	44,460,000	$52,838,000	$62,791,000	$72,718,000	$80,548,000	$89,216,000	$98,812,000
OTHER INCOME	662,733	255,000	255,000	255,000	255,000	255,000	255,000	255,000	255,000
INTEREST INCOME	1,579,221	1,052,000	604,000	23,000	29,000	31,000	30,000	28,000	62,000
OPERATING INCOME	35,862,705	38,984,666	45,319,000	53,116,000	63,075,000	73,004,000	80,833,000	89,499,000	99,129,000
NEW PLANT O&M COSTS			0	0		(250,000)	(252,500)	(255,025)	(257,575)
OPERATING EXPENSES	(15,354,771)	(19,425,617)	(21,024,164)	(21,780,388)	(22,448,209)	(23,138,679)	(23,852,612)	(24,375,034)	(24,862,535)
NET INCOME EXCLUDING DEP.	20,507,934	19,559,049	24,294,836	31,335,612	40,626,791	49,615,321	56,727,888	64,868,941	74,008,890
IMPACT FEES	971,344	700,000	700,000	724,500	749,858	776,103	803,267	831,381	860,479
STATE LOAN (NWQ)	8,500,000								
SHORT TERM FINANCING PROCEEDS									
WIFIA LOAN				67,429,000	85,926,000	65,057,000	31,865,000	6,395,000	2,112,000
NET BOND PROCEEDS			55,000,000	39,000,000	97,000,000	65,000,000	27,000,000		
ISSUE COSTS (PROCEEDS)			307,000	218,000	542,000	363,000	151,000	0	0
ISSUE COSTS (EXP)			(307,000)	(218,000)	(542,000)	(363,000)	(151,000)	0	0
OTHER CONTRIBUTIONS	978,525	2,020,000	2,020,000	2,020,000	720,000	520,000	520,000	520,000	520,000
CAPITAL OUTLAY	(847,714)	(1,302,569)	(8,694,000)	(823,000)	(823,000)	(823,000)	(823,000)	(823,000)	(823,000)
STATE LOAN DEBT REPAYMENT			(6,375,000)	(2,125,000)					
NEW DEBT SERVICE		0	(719,000)	(2,700,000)	(5,216,000)	(9,091,000)	(12,731,000)	(14,415,000)	(16,324,000)
DEBT SERVICE	(5,561,477)	(6,050,603)	(6,055,000)	(8,574,000)	(8,560,000)	(8,561,000)	(8,935,850)	(8,561,000)	(8,561,000)
OTHER INCOME & EXPENSE	4,040,678	(4,633,172)	35,877,000	94,951,500	169,796,858	112,878,103	37,698,417	(16,052,619)	(22,215,521)
NET FOR CAPITAL	24,548,612	14,925,877	60,171,836	126,287,112	210,423,649	162,493,424	94,426,305	48,816,322	51,793,369
CAPITAL IMPROVEMENTS	$ (33,243,806)	(60,892,051)	(98,370,500)	(125,728,000)	(210,160,000)	(162,630,000)	(94,660,000)	(45,480,000)	(30,321,000)
NEW WRF IN CIP			(54,700,000)	(82,910,000)	(175,360,000)	(132,770,000)	(65,030,000)	(13,050,000)	(4,310,000)
CASH INCREASE/(DECREASE)	(8,695,194)	(45,966,174)	(38,198,664)	559,112	263,649	(136,576)	(233,695)	3,336,322	21,472,369
		0							
BEGINING CASH BALANCE	94,916,245	86,221,051	40,254,877	2,056,213	2,615,325	2,878,974	2,742,398	2,508,703	5,845,025
CASH INCREASE/(DECREASE)	(8,695,194)	(45,966,174)	(38,198,664)	559,112	263,649	(136,576)	(233,695)	3,336,322	21,472,369
ENDING BALANCES	**86,221,051**	**40,254,877**	**2,056,213**	**$2,615,325**	**$2,878,974**	**$2,742,398**	**$2,508,703**	**$5,845,025**	**$27,317,394**
RESTRICTED/RESERVED	**(10,789,378)**								
AVAILABLE ENDING BALANCE	**$75,431,673**	**40,254,877**	**2,056,213**	**$2,615,325**	**$2,878,974**	**$2,742,398**	**$2,508,703**	**$5,845,025**	**$27,317,394**
RATE CHANGE	30%	15%	18%	18%	18%	15%	10%	10%	10%
Cash Reserve Ratio	**562%**	**207%**	**10%**	**12%**	**13%**	**12%**	**10%**	**24%**	**109%**
Debt Service Coverage	**3.69**	**3.23**	**1.85**	**2.34**	**2.95**	**2.81**	**2.62**	**2.82**	**2.97**
DEBT SERVICE % OF GROSS OPERATING REVENUE	16%	16%	15%	21%	22%	24%	27%	26%	25%
MONTHLY RESIDENTIAL UTILITY BILL AT 4 CCF	10.60	12.16	14.68	17.32	20.44	23.51	25.86	28.45	31.30
MONTHLY RESIDENTIAL UTILITY BILL AT 8 CCF	21.20	24.32	29.36	34.64	40.88	47.01	51.71	56.88	62.57

Exhibit D

WIFIA Fact Sheet

WIFIA PROGRAM

The WIFIA program accelerates investment in our nation's water infrastructure by providing long-term, low-cost supplemental loans for regionally and nationally significant projects. The WIFIA program was established by the Water Infrastructure Finance and Innovation Act of 2014.

ELIGIBILITY

Eligible borrowers

- Local, state, tribal, and federal government entities
- Partnerships and joint ventures
- Corporations and trusts
- Clean Water and Drinking Water State Revolving Fund (SRF) programs

WIFIA can fund development and implementation activities for eligible projects

- Wastewater conveyance and treatment projects
- Drinking water treatment and distribution projects
- Enhanced energy efficiency projects at drinking water and wastewater facilities
- Desalination, aquifer recharge, and water recycling projects
- Acquisition of property if it is integral to the project or will mitigate the environmental impact of a project
- A combination of eligible projects secured by a common security pledge or submitted under one application by an SRF program

FUNDING AVAILABILITY

EPA announces WIFIA funding availability and application process details in the Federal Register and on its website.

IMPORTANT PROGRAM FEATURES

- **$20 MIL** — Minimum project size for large communities.
- **$5 MIL** — Minimum project size for small communities (population of 25,000 or less).
- **49%** — Maximum portion of eligible project costs that WIFIA can fund.
- **35 YEARS** — Maximum final maturity date from substantial completion.
- **5 YEARS** — Maximum time that repayment may be deferred after substantial completion of the project.
- **%** — Interest rate will be equal or greater to the US Treasury rate of a similar maturity.
- Projects must be creditworthy.
- NEPA, Davis-Bacon, American Iron and Steel, and all federal cross-cutter provisions apply.

STAY IN TOUCH

EPA

WEBSITE: www.epa.gov/wifia

EMAIL: wifia@epa.gov

Sign-up to receive announcements about the WIFIA program at https://tinyurl.com/wifianews

November 2016

EPA-830-F-16-003

WIFIA PROGRAM

The Water Infrastructure Finance and Innovation Act (WIFIA) program accelerates investment in our nation's water infrastructure by providing long-term, low-cost supplemental loans for nationally and regionally significant projects. Borrowers benefit from receiving low, fixed interest rate loans with flexible financial terms.

WIFIA LOANS OFFER A LOW, FIXED INTEREST RATE

A SINGLE FIXED RATE IS ESTABLISHED AT CLOSING. A borrower may receive multiple disbursements over several years at the same fixed interest rate.

RATE IS EQUAL TO THE US TREASURY RATE OF A SIMILAR MATURITY. The WIFIA program sets its interest rate based on the U.S. Treasury rate on the date of loan closing. The rate is calculated using the weighted average (WAL) life of the loan rather than the loan maturity date. The WAL is generally shorter than the loan's actual length resulting in a lower interest rate.

RATE IS NOT IMPACTED BY BORROWER'S CREDIT OR LOAN STRUCTURE. All borrowers benefit from the AAA Treasury rate, regardless of whether they are rated AA or BBB. The WIFIA program does not charge a higher rate for flexible financial terms.

WIFIA LOANS PROVIDE FLEXIBLE FINANCIAL TERMS

CUSTOMIZED REPAYMENT SCHEDULES. Borrowers can customize their repayments to match their anticipated revenues and expenses for the life of the loan. This flexibility provides borrowers with the time they may need to phase in rate increases to generate revenue to repay the loan.

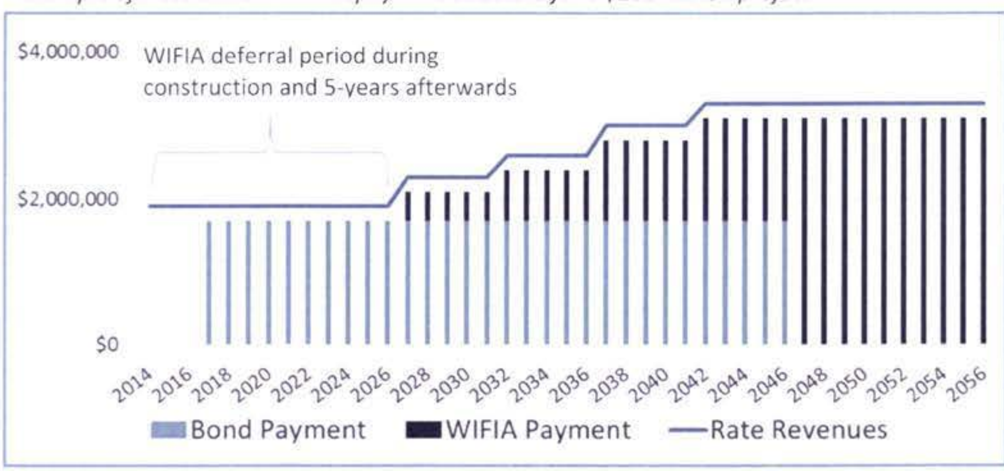
LONG REPAYMENT PERIOD. WIFIA loans may have a length of up to 35 years after substantial completion, allowing payment amounts to be smaller throughout the life of the loan.

DEFERRED PAYMENTS. Payments may be deferred up to 5 years after the project's substantial completion.

SUBORDINATION. Under certain circumstances, WIFIA may take a subordinate position in payment priority, increasing coverage ratios for senior bond holders.

WIFIA LOANS CAN BE COMBINED WITH VARIOUS FUNDING SOURCES. WIFIA loans can be combined with private equity, revenue bonds, corporate debt, grants, and State Revolving Fund (SRF) loans.

Example of a customized debt repayment structure for a $100 million project



WIFIA loan's flexible repayment schedule allows for rate increases to be phased in over a longer period of time.

EPA

WEBSITE: www.epa.gov/wifia
EMAIL: wifia@epa.gov
ANNOUNCEMENTS: Sign-up at https://tinyurl.com/wifianews

Exhibit E

Official correspondence between Salt Lake City Department of Public Utilities and Utah Department of Environmental Quality establishing a permit variance for Technology-Based Phosphorus Effluent Limits, dated November 6, 2017 through March 21, 2019

State of Utah
GARY R. HERBERT
Governor
SPENCER J. COX
Lieutenant Governor

Department of
Environmental Quality
Alan Matheson
Executive Director
DIVISION OF WATER QUALITY
Erica Brown Gaddis, PhD
Director

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PUBLIC UTILITIES

March 21, 2019

Laura Briefer
Director of Department of Public Utilities
Salt Lake City Corporation
1530 South West Temple
Salt Lake City, Utah 84115

Subject: **Response to Request for Change in Condition for Variance to Technology-Based Phosphorus Effluent Limitations (TBPEL)**
UPDES Permit No. UT0021725

Dear Ms. Briefer,

Part 12.d. of the 2018 Salt Lake City Permit variance for technology-based phosphorus effluent limits (SLC Variance for TBPEL) defines variance milestones including the submission of a City Council resolution supporting pursuit of a facility upgrade. SLC Public Utilities requested the due date for Part 12.d. be extended from May 1, 2019 to July 1, 2019 in a letter dated March 13, 2019 (DWQ-2019-002805). This request is based on the timing of the Salt Lake City Mayor's budget release date and City Council meetings. The request for extension is approved. The requirements of Part 12.d. are hereby altered to:

d. By no later than ~~May 1~~ July 1, 2019, SLC Public Utilities shall submit to DWQ:

i. A formal letter committing to the selected biological phosphorus removal technology (full BNR or the BNR facility operated as EBPR) including project schedule, and budget analysis (including project costs and funding information).

ii. A City Council resolution supporting the pursuit of the facility upgrade to the selected biological phosphorus removal technology. The resolution shall include the approximate budget for the facility upgrade.

iii. A proposed schedule of when completed design plans for permitting will be submitted to DWQ.

The submission of these 3 items by no later than July 1, 2019 will be considered in full compliance with Part 12.d. of the SLC Variance for TBPEL.

DWQ does not view this modification as a substantive change or a re-visitation of the variance as no rationale of the justification is being reevaluated. The final TBPEL compliance date remains the same; as such this due date alteration will not be public noticed.

Should you have any questions regarding this matter, please contact Mr. Ken Hoffman at (801) 536-4313 (kenhoffman@utah.gov) of my staff.

Sincerely,

Erica B. Gaddis

Erica Brown Gaddis, PhD
Director

EBG/KH/blj

DWQ-2019-002804

JACQUELINE M. BISKUPSKI
Mayor

DEPARTMENT OF PUBLIC UTILITIES

March 13, 2019

Utah Department of Environmental Quality
Division of Water Quality
PO Box 144870
Salt Lake City, UT 84114—4870

Attention: Erica Gaddis, Director

Request for Change in Condition for Variance to Technology-Based Phosphorus Effluent Limitations (TBPEL); UPDES Permit No. UT0021725

Dear Director Gaddis:

On May 29, 2018, Utah Department of Environmental Quality (UDEQ) transmitted its approval of a variance to the TBPEL permit variance issued for Salt Lake City Department of Public Utilities (SLCDPU) (UPDES Permit No. UT0021725). One condition of the variance states that by May 1, 2019, *"Salt Lake City must submit a City Council resolution supporting the pursuit of the facility upgrade to the selected biological phosphorus removal technology. The resolution shall include the approximate budget for the facility upgrade."*

As we have been preparing materials for our City Council to consider along with this resolution, we realized that in order to meet the May 1, 2019 deadline for the resolution, SLCDPU would need to request a City Council resolution approving the approximate budget for the facility reconstruction prior to the Mayor and Council's completion of the City's overall budget process for Fiscal Year (FY) 2020. This is especially relevant in that portions of SLCDPU's proposed FY 2020 budget include revenue bonding and design costs associated with the facility reconstruction.

Since our FY 2020 budget year begins on July 1, 2019, and our City Council generally approves the City's overall budget in June, we are requesting that that we provide your office with the required City Council resolution by July 1, 2019. This condition change will be in better alignment with the sequence of Salt Lake City's municipal budgeting process.

Thank you for taking the time to consider this request. SLCDPU is committed to the reconstruction and upgrade of our Water Reclamation Facility and meeting the January 1, 2025 TBPEL compliance date. Please do not hesitate to contact me with any questions or concerns at 801.483.6741, or laura.briefer@slcgov.com.

Sincerely,

Laura Briefer
Director

cc: Jesse Stewart, Deputy Director
Rusty Vetter, SLC Attorney's Office

State of Utah
GARY R. HERBERT
Governor

SPENCER J. COX
Lieutenant Governor

Department of
Environmental Quality

Alan Matheson
Executive Director

DIVISION OF WATER QUALITY
Erica Brown Gaddis, Ph.D.
Director

May 29, 2018

Laura Briefer
Director of Department of Public Utilities
Salt Lake City Corporation
1530 South West Temple
Salt Lake City, Utah 84115

Dear Ms. Briefer,

Subject: Approval of Variance to Technology-based Phosphorus Effluent Limitations (TBPEL) under R317-1-3.3.C.e.

We have completed our review of your "Technology-based Phosphorus Effluent Limits (TBPEL) Rule Compliance Postponement Request", that was submitted in regard to the Salt Lake City Department of Public Utilities (SLC Public Utilities) wastewater treatment plant. The request was submitted as a proposed demonstration of due diligence variance requirements of R317-1-3.3.C.e. The request was submitted by SLC Public Utilities, signed by Laura Briefer, and received on November 9, 2017 (DWQ-2017-011173). The request included documentation of the following items:

1. Salt Lake City Department of Public Utilities Projects at the SLCWRF: Nutrient Project Pre-Design Report, Waterworks Engineers (August, 2017).

2. Sewer Utility Capital Improvement Plan (CIP) Budget – Five Year Projected Budget 2018-2022. (by reference)

3. Clarification of Salt Lake City Department of Public Utilities application for a variance from R317-1-3.3, Technology-Based Limits for Controlling Phosphorus Pollution. (March 26, 2018)

These documents demonstrate that SLC Public Utilities is committed to, and diligently pursuing design, financing, and planning for construction of treatment works necessary to meet the TBPEL. These documents further demonstrate that SLC Public Utilities will be unable to complete facilities improvements necessary to comply with the TBPEL by the January 1, 2020 deadline. As

a result, the attached permit variance to the TBPEL under R317-1-3.3.C.e is hereby issued subject to the following conditions:

1. SLC Public Utilities shall comply with the requirements of the attached Permit Variance for Technology-Based Phosphorus Effluent Limits.

2. Nothing in this concept approval letter relieves SLC Public Utilities from compliance with their current UPDES permit requirements.

Should you have any questions, please contact either Ken Hoffman at (801) 536-4313 (kenhoffman@utah.gov) or Jeff Studenka at (801) 536-4395 (jstudenka@utah.gov) of my staff.

Sincerely,

Erica B. Gaddis

Erica Brown Gaddis, PhD
Director

EBG/KH/JS/blj

Enclosure (1): 1. Permit Variance for Technology-Based Phosphorus Effluent Limits (DWQ-2018-003574)

DWQ-2018-003572

UTAH DIVISION OF WATER QUALITY

IN THE MATTER OF Salt Lake City Department of Public Works 1530 South West Temple Salt Lake City, Utah 84115 UPDES PERMIT NO. UT0021725	PERMIT VARIANCE FOR TECHNOLOGY-BASED PHOSPHORUS EFFLUENT LIMITS

BACKGROUND

1. Salt Lake City Department of Public Utilities' ("SLC Public Utilities") wastewater treatment plant in Salt Lake City, Utah (the "Facility") provides wastewater services within Salt Lake County.

2. SLC Public Utilities' operations at the Facility are undertaken subject to UPDES Discharge Permit No. UT0021725 ("Permit").

3. The Facility is required to achieve technology-based phosphorus effluent limits ("TBPEL") on or before January 1, 2020, unless a variance is granted. *See* UAC R317-1-3.3.

4. SLC Public Utilities submitted a variance request, dated November 6, 2017 to the Utah Division of Water Quality ("DWQ"), seeking an extension of the TBPEL implementation date (the "Variance Request."). The Variance Request is based on the fact that SLC Public Utilities is in the process of designing and constructing improvements to the Facility to meet TBPEL requirements, however such improvements cannot be completed prior to January 1, 2020, despite SLC Public Utilities' diligence.

5. SLC Public Utilities submitted a clarification to their variance request, dated March 26, 2018 to the DWQ. This clarification formally replied to items of question by DWQ concerning their variance request and potential milestones for variance approval.

6. Utah law provides that DWQ may grant a variance as to the implementation date for compliance with the TBPEL in the event that the operator demonstrates due diligence toward construction of a treatment facility designed to meet TBPEL, provided that such compliance date shall not be later than January 1, 2025. *See* UAC R317-1-3.3.C.e.

7. The Director of DWQ has determined that SLC Public Utilities has met its burden to show diligence within the meaning of the UAC R317-1-3.3 and that a variance is appropriate, subject to the limitations and conditions provided herein.

AUTHORITY

8. The Director of DWQ has authority to grant a variance as to the implementation deadline for TBPEL pursuant to UAC R317-1-3.3 and the corresponding provisions of the Utah Water Quality Act.

9. The State of Utah administers the Utah Pollution Discharge Elimination System (UPDES) permit program under the Utah Water Quality Act.

DUE DILIGENCE - FINDINGS

10. The Variance Request included the following submissions, among others:

a. Salt Lake City Department of Public Utilities Projects at the SLCWRF: Nutrient Project Pre-Design Report, Waterworks Engineers (August, 2017).

b. Sewer Utility Capital Improvement Plan (CIP) Budget – Five Year Projected Budget 2018-2022. (by reference)

c. Clarification of Salt Lake City Department of Public Utilities application for a variance from R317-1-3.3, Technology-Based Limits for Controlling Phosphorus Pollution. (March 26, 2018)

11. Based on the foregoing submissions, the Director has determined that SLC Public Utilities has established due diligence toward construction of Biological Phosphorus Removal treatment facility upgrade designed to meet TBPEL, within the meaning of UAC R317-1-3.3.C.e.

VARIANCE

12. The Director hereby grants SLC Public Utilities a variance as to the compliance date to achieve TBPEL, until the time that its facility improvements described in the Variance Request are operational; subject to the following conditions:

a. This variance does not extend beyond January 1, 2025. SLC Public Utilities must comply with all TBPEL requirements by that date.

b. Pursuant to UAC R317-1-3.3.C.2, this variance is subject to re-evaluation in the event that there is any substantive change in the facility design or construction plans provided in the Variance Request. SLC Public Utilities must provide timely notice to DWQ of any such substantive changes.

c. By no later than January 31, 2022, SLC Public Utilities shall submit to DWQ an approvable complete construction permit application per UAC R317-3 for construction permitting of a facility to biologically remove phosphorus to 1.0 mg/L or less.

d. By no later than May 1, 2019, SLC Public Utilities shall submit to DWQ:

   i. A formal letter committing to the selected biological phosphorus removal technology (full BNR or the BNR facility operated as EBPR) including project schedule, and budget analysis (including project costs and funding information).

   ii. A City Council resolution supporting the pursuit of the facility upgrade to the selected biological phosphorus removal technology. The resolution shall include the approximate budget for the facility upgrade.

   iii. A proposed schedule of when completed design plans for permitting will be submitted to DWQ.

e. Beginning no later than July 1, 2019, and for every year thereafter while this variance is in effect, SLC Public Utilities agrees to submit to DWQ an annual report relating to its phosphorus discharges (the "Annual Report"). The scope of the Annual Report shall include descriptions of all projects and work necessary, in reasonable detail, to achieve compliance with the TBPEL rule. The Annual Report will provide a summary of progress and milestones achieved in all construction, study, funding, planning, and design projects during the previous reporting period, projected progress and milestones scheduled to be completed during the following reporting period, and if the project(s) are on schedule. The Annual Report will also provide information on effluent phosphorus concentrations to determine SLC Public Utilities' compliance with Parts 11.e. and 11.f. of this variance, noted below.

   i. The Annual Report must specifically state the economic benefit per year SLC Public Utilities will receive from January 1 to December 31 of the coming year from this due diligence variance for not treating total phosphorus to 1.0 mg/L.

f. No total phosphorus effluent limitation will be added to the Permit before January 1, 2020.

g. Effective January 1, 2020, DWQ will impose the following interim effluent limitation under the Permit: total phosphorus annual average effluent limitation of 3.8 mg/L.

h. Upset Conditions from Part VI.H of UPDES Permit No. UT0021725

i. Effect of an upset. An upset constitutes an affirmative defense to an action brought for noncompliance with technology based permit effluent limitations if the requirements of paragraph 2 (ii) of this section are met. Director's administrative determination regarding a claim of upset cannot be judiciously challenged by the permittee until such time as an action is initiated for noncompliance.

ii. Conditions necessary for a demonstration of upset. A permittee who wishes to establish the affirmative defense of upset shall demonstrate, through properly signed, contemporaneous operating logs, or other relevant evidence that:

1. An upset occurred and that the permittee can identify the cause(s) of the upset;

2. The permitted facility was at the time being properly operated;

3. The permittee submitted notice of the upset as required under *Part V.H, Twenty-four Hour Notice of Noncompliance Reporting* of UPDES Permit No. UT0021725; and,

4. The permittee complied with any remedial measures required under *Part VI.D, Duty to Mitigate* of UPDES Permit No. UT0021725.

iii. Burden of proof. In any enforcement proceeding, the permittee seeking to establish the occurrence of an upset has the burden of proof.

Erica B. Gaddis

Erica Brown Gaddis, PhD
Director
Utah Division of Water Quality

Date: 5/29/18

DWQ-2018-003574

State of Utah

GARY R. HERBERT
Governor

SPENCER J. COX
Lieutenant Governor

Department of
Environmental Quality

Alan Matheson
Executive Director

DIVISION OF WATER QUALITY
Erica Brown Gaddis, PhD
Director

APR 17 2018

Newspaper Agency
143 South Main
Salt Lake City, UT 84110

Email: naclegal@mediaoneutah.com
Account: 9001365712

ATTENTION: Legal Advertising Department

This letter will confirm authorization to publish the attached NOTICE in The Salt Lake Tribune or Deseret News in the first available edition. Please mail the invoice and affidavit of publication to:

Department of Environmental Quality
Division of Water Quality
Attn: Emily Canton
P.O. Box 144870
Salt Lake City, Utah 84114-4870

If there are any questions, please contact Savannah Miller at (801) 536-4316. Thank you for your assistance.

Sincerely,

for

Matthew Garn P.E., Manager
UPDES Surface Water Section

MG/JAS/smm

DWQ-2018-004188

State of Utah
GARY R. HERBERT
Governor
SPENCER J. COX
Lieutenant Governor

Department of
Environmental Quality

Alan Matheson
Executive Director

DIVISION OF WATER QUALITY
Erica Brown Gaddis, PhD
Director

April 18, 2018
DIVISION OF WATER QUALITY
UTAH DEPARTMENT OF ENVIRONMENTAL QUALITY
PUBLIC NOTICE OF VARIANCE TO TBPEL IMPLEMENTATION DATE

PURPOSE OF PUBLIC NOTICE

The purpose of this public notice is to declare the State of Utah's intention to grant a variance to the implementation deadline for Technology Based Phosphorus Effluent Limit (TBPEL) compliance to Salt Lake City Wastewater Treatment Facility. Pursuant to *UAC R317-1-3.3* and corresponding provisions of the Utah Water Quality Act.

PERMIT INFORMATION

PERMITTEE NAME:	Salt Lake City Water Reclamation Facility
MAILING ADDRESS:	1530 S West Temple, Salt Lake City, UT 84114
TELEPHONE NUMBER:	(801) 483-6670
FACILITY LOCATION:	1365 West 2300 North, Salt Lake City, UT 84116
UPDES PERMIT NO.:	UT0021725
RECEIVING WATERS:	Jordan River

BACKGROUND

The Salt Lake City Water Reclamation Facility (SLC) serves the greater Salt Lake City area, including the University of Utah. SLC submitted a variance request, dated November 6, 2017 to the Utah Division of Water Quality "DWQ", seeking a variance to the TBPEL implementation date. The Variance Request is based on the fact that SLC is in the process of designing and constructing improvements to the Facility to meet TBPEL requirements, however, such improvements cannot be completed prior to January 1, 2020, despite SLC's diligence.

PUBLIC COMMENTS

Public comments are invited any time prior to the deadline of the close of business on May 18, 2018. Written public comments can be submitted to: Jeff Studenka, UPDES Surface Water Section, Utah Division of Water Quality, P.O. Box 144870, Salt Lake City, Utah 84114-4870 or by email at: jstudenka@utah.gov. After considering public comment the Utah Division of Water Quality may execute the variance, revise it or abandon it. The variance is available for public review under https://deq.utah.gov/public-notices/water-quality-public-notices. If internet access is not available, a copy may be obtained by calling Jeff Studenka at 801-536-4395.

DWQ-2018-004186

JACQUELINE M. BISKUPSKI
Mayor

**DEPARTMENT OF
PUBLIC UTILITIES**

March 26, 2018

Utah Department of Environmental Quality
Division of Water Quality
P.O. Box 144870
Salt Lake City, UT 84114-4870
Attn: Ken Hoffman, P.E.

Subject: Clarification of Salt Lake City Department of Public Utilities application for a variance from R317-1-3.3, Technology-Based Limits for Controlling Phosphorus Pollution

Dear Mr. Hoffman:

The intent of this letter is to provide the additional information requested in your e-mail communication dated February 23, 2018 related to the Salt Lake City Department of Public Utilities (City) application requesting a five-year variance (from January 1, 2020 to January 1, 2025) for compliance with the Technology-Based Phosphorous Effluent Limit (TBPEL) of 1.0 milligram per liter (mg/L) for the Salt Lake City Water Reclamation Facility (SLCWRF), UPDES Permit UT0021725.

Based upon your response, it is our understanding that we need to provide the following items to the Division of Water Quality (DWQ) as addendum to our variance request that was submitted to the DWQ on 11/06/2017 (see attached):

1. Planning/feasibility requirement
2. Schedule
3. Specified Technology and estimated budget
4. Milestone for submission of complete designs
5. Interim phosphorus limit

Each of these items is discussed in the subsequent paragraphs. Please let us know if you need additional information than what is provided.

1. Planning/Feasibility Requirement

Per your above referenced e-mail, it is our understanding that the previously submitted SLCWRF Nutrient Project Pre-Design Report meets the planning/feasibility requirement of the variance requests.

2. Schedule

The City is selecting an engineering consulting firm to provide professional design and construction management services for the duration of our project. The selection is expected to be finalized by May 2018. The project schedule and design concept is anticipated to be finalized by May of 2019. We will provide this information to DWQ for their review and comment.

[illegible]
[illegible] 84115

WWW.SLCGOV.COM
TEL 801-483-6900 FAX 801-483-6818

3. Specified Technology and Estimated Budget

The City is planning to design and construct facilities to provide full biological nutrient removal (BNR). The City plans to design the facilities in such a way that it can be operated to provide either enhanced biological phosphorus removal (EBPR) or full BNR. The specific process design for these facilities (e.g., MLE, Westbank) will be finalized with the selected design firm. We anticipate the design concept will be finalized by May of 2019 and presented in the form of a design report for the entire facility.

The estimated budget for this project, based on the current 15% design, is $325 - 510 million. Please note, this budget is based on the preliminary design, and will be updated and modified during final design concept development. As stated in our initial letter requesting a variance, we offer the following of our demonstrated financial commitment to this large capital project:

- The Five Year Projected Budget for fiscal years 2018-2022 includes planned expenditures for the current fiscal year and proposed budget for out years for the necessary capital projects at the plant. Attached are proposed expenditures for the fiscal year 2018/19 with projections through 2022.
- A capital financial plan has been prepared to include the design and construction of the new facility. The financial plan includes bonding completed in 2017 ($78 million between collections and the SLCWRF) and additional planned bonding for more than $300 million through fiscal year 2024 for final design and construction of the facility. The projected bonding amounts may change pending refined overall project costs.
- Beginning in fiscal year 2016, the City implemented the first of several planned rate increases to raise revenue for the WRF project and account for bonding debt service. The rate increases approved by the Salt Lake City Council in fiscal years 2016, 2017, and 2018 were 8%, 12%, and 30% increases, respectively. We have presented our plan for anticipated rate increases for fiscal years 2019, 2020, 2021, and 2023 at 15%, 15%, 10%, and 8%, respectively. The projected rate increases may change pending refined project costs and bonding amounts and schedules. The Salt Lake City Mayor and Council understand the need for the SLCWRF project, and are aware of the projected rate increases and financing plan.
- The City has communicated with DWQ regarding potential funding sources through the State Revolving Fund Loan; however, additional discussion with the City's financial advisors, and with DWQ will be conducted before determining the best course of action.

4. Milestone for Submission of Complete Design

It is anticipated that this project will need to be delivered in several construction packages in order to be completed to meet the requested January 1, 2025 deadline. We would like to work with DWQ to optimize the submittal and review of these packages to ensure a complete and well-reviewed design prior to beginning construction. By May 2019, we plan to have finalized the conceptual design of the facility, which would include a design report for the entire facility, a project schedule, and a list of design/construction packages. We will work with DWQ prior to finalizing this schedule and package delivery list to plan appropriate time for submittal review and to ensure DWQ is in agreement with the review plan moving forward. In addition, we have discussed with DWQ having semi-annual project update meetings with the City, our design engineers, and DWQ staff.

5. Interim Phosphorus Limit

DWQ may propose a draft interim phosphorous effluent limit of 3.6 milligrams per liter (mg/L). This concentration is roughly equivalent to the SLCWRF effluent annual average. Although the SLCWRF is not currently specifically designed to treat phosphorous to low levels, the facility has typically removed approximately 30% of the influent phosphorous concentration. Our effluent

concentrations are directly tied to the influent phosphorous concentrations; therefore, we propose that no interim phosphorous limit is established. Rather, the SLCWRF will continue to operate with the goal of 30% reduction of influent phosphorous concentrations as our pre-treatment division continues to limit phosphorous influent concentrations.

Commitment

In summary, by May 1, 2019, the City shall submit to DWQ:

I. A formal letter committing to the selected biological phosphorus removal technology (full BNR or the BNR facility operated as EBPR) including project schedule, and budget analysis (including project costs and funding information).
II. A City Council resolution supporting the pursuit of the facility upgrade to the selected biological phosphorus removal technology. The resolution shall include the approximate budget for the facility upgrade.
III. A proposed schedule of when completed design plans for permitting will be submitted to DWQ.
IV. A commitment to operate the facility with the goal of 30% reduction of influent phosphorous concentrations while design and construction of the new SLCWRF is conducted.

In return, we request that DWQ will approve the proposed schedule and the submission of complete design plans in accordance with the approved schedule that is a requirement of this variance.

We thank you for your consideration of our application for variance and request that you contact us with any questions you may have.

Sincerely,
JESSE A. STEWART FOR

Laura Briefer
Director
Salt Lake City Corporation
Department of Public Utilities

cc: U.S. EPA, Region 8
Jesse Stewart, Jason Brown, Jamey West, Derek Velarde, Michelle Barry - SLCDPU
Patrick Leary, Chief of Staff, Salt Lake City Mayor's Office
Cindy Gust-Jensen, Director, Salt Lake City Council
File

Calfo, Janine

From:	Stewart, Jesse
Sent:	Monday, March 19, 2018 7:39 AM
To:	Briefer, Laura
Subject:	FW: TBPEL Variance request

This is to accompany the letter regarding the TBPEL Variance request.

Jesse

From: Ken Hoffman [mailto:kenhoffman@utah.gov]
Sent: Friday, February 23, 2018 5:01 PM
To: Stewart, Jesse <Jesse.Stewart@slcgov.com>
Subject: TBPEL Variance request

Good talking with you yesterday. You asked me to send an email to clarify potential variance milestones. The items we have asked for in a variance request has been planning/feasibility, schedule, and a governing body resolution for a project with specified technology and estimated budget. Your pre-design report covers your planning/feasibility requirement. However, it is a bit undefined on schedule and a selected technology.

In addition, to these items the draft variances approvals are including a milestone for submission of complete designs and an interim phosphorus limit. Your draft interim limit is proposed at 3.6 mg/L. This is intended as a keep doing what you're doing with no additional treatment then has occurred the past 2 years.

Milestones
Technology - on the phone you stated SLC will be going with the BNR project described in your report. So maybe you can wrap up the planning/feasibility piece with a brief letter.

Schedule - it sound like you would like to commit to supplying a schedule by the end of the year once you have your engineer on board.

Resolution - This probably again needs a little time to settle on the project, budget, timeline

Completed Plans - It seemed like you would like to include this as part of your schedule and have it determine the timeline for complete plans.

I've included some draft language at the bottom which could address each of these items.

Last, let me reiterate it is my goal to not create any new work for you but just track the good hard work you and Salt Lake City are already doing. Please let me know if you have thoughts as I'm happy to take feedback.

Thank you,
Ken
--

Ken Hoffman, P.E. | **Environmental Engineer**

Engineering Section

Phone: 801.536.4313

c. By no later than January 1, 2019, SLC Public Utilities shall submit to DWQ:

i. A formal letter committing to the selected biological phosphorus removal technology including project schedule and budget analysis including project costs and how the project will be funded.

ii. A resolution instructing SLC Public Utilities staff to pursue the facility upgrade to the selected biological phosphorus removal technology. The resolution shall include the approximate budget for the facility upgrade.

iii. A proposed schedule of when complete design plans for permitting will be submitted.

a) DWQ will approve the proposed schedule and the submission of complete design plans in accordance with the approved schedule will be a requirement of this variance.

State of Utah

GARY R. HERBERT
Governor

SPENCER J. COX
Lieutenant Governor

Department of
Environmental Quality

Alan Matheson
Executive Director

DIVISION OF WATER QUALITY
Erica Brown Gaddis, PhD
Director

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PUBLIC UTILITIES

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MAR 02 2018

FEB 27 2018

Laura Briefer, Director
Salt Lake City Water Reclamation Facility
1530 S West Temple
Salt Lake City, UT 84115

Dear Ms. Briefer:

Subject: UPDES Permit No. UT0021725, Salt Lake City Water Reclamation Facility, Review of Technology-Based Phosphorus Effluent Limits (TBPEL) Variance Request

The Division of Water Quality (DWQ) has received Salt Lake City Water Reclamation Facility's request for variance to the TBPEL rule (R317-1-3.3). Salt Lake City Water Reclamation Facility is requesting this variance of the condition found in R317-1-3.3.C.1.e, for due dilligence.

Ken Hoffman has been assigned to review the variance request for your facility. A fee will be assessed based on the amount of time needed to complete the review of the variance request. The fee schedule, as approved by the legislature, for Technical Review and assistance given is $90.00 per hour. It is estimated that the variance review will take between 12 and 40 hours, with an estimated cost between $1080.00 and $3600.00. Once the variance request is completed, an invoice will be sent to Salt Lake City Water Reclamation Facility.

If you have any questions regarding the variance review process, please contact Ken at kenhoffman@utah.gov or at (801) 536-4313. You may also contact Jeff Studenka at jstudenka@utah.gov or at (801) 536-4395 with questions about your UPDES permit.

Sincerely,

Erica B Gaddis

Erica Brown Gaddis, PhD
Director
EBG:MG:KH:JS:smm

195 North 1950 West • Salt Lake City, UT
Mailing Address: P.O. Box 144870 • Salt Lake City, UT 84114-4870
Telephone (801) 536-4300 • Fax (801) 536-4301 • T.D.D. (801) 536-4284
www.deq.utah.gov

JACQUELINE M. BISKUPSKI
Mayor

DEPARTMENT OF
PUBLIC UTILITIES

November 6, 2017

Utah Department of Environmental Quality
Division of Water Quality
P.O. Box 144870
Salt Lake City, UT 84114-4870
Attn: Erica Gaddis, Director

Subject: Salt Lake City Department of Public Utilities application for a variance from R317-1-3.3, Technology-Based Limits for Controlling Phosphorus Pollution

Dear Director Gaddis:

The Salt Lake City Department of Public Utilities (SLC Public Utilities) is submitting this application requesting a five-year variance (from January 1, 2020 to January 1, 2025) for compliance with the Technology-Based Phosphorous Effluent Limit (TBPEL) of 1.0 milligram per liter (mg/L) for the Salt Lake City Water Reclamation Facility (SLC Water Reclamation Facility), UPDES Permit UT0021725. SLC Public Utilities has worked with professional environmental engineering firms and members of the research and academic community to identify appropriate fiscal and technological approaches to achieve the TBPEL, while also addressing other plant needs (e.g., replacement of aged facilities; addressing hydraulic, structural, and electrical insufficiencies; meeting sustainability objectives).

SLC Public Utilities has determined construction of a new facility capable of meeting the TBPEL is in the best interests of the public, environment, and SLC Public Utilities. Over the past two years, SLC Public Utilities has worked with consultants to prepare the pre-design for this Nutrient/Facility Upgrade project (see attached Nutrient Project Pre-Design Report).

Based on the magnitude of the project (e.g., the time required for design, and construction of the facility, and procurement of funds), SLC Public Utilities requests a five-year variance from the Utah Department of Environmental Quality (UDEQ) Division of Water Quality (DWQ) for compliance with the TBPEL. This request for a variance is per Utah Administrative Code R317-1-3.3.C.1e, which states,

> "Where the owner of a non-lagoon discharging treatment works demonstrates due diligence toward construction of a treatment facility designed to meet the TBPEL, the compliance date shall be no later than January 1, 2025."

SLC Public Utilities offers as demonstration of our due diligence, the following:

- **Nutrient Project Pre-Design Report (2017)** - This Nutrient Project Pre-Design Report (attached) provides the basis of design and pre-design for facility upgrades. In addition, SLC Public Utilities has developed and posted a Request for Qualifications (RFQ) with the

1530 South West Temple
Salt Lake City, Utah 84115

www.slcgov.com
Tel 801-483-6900 Fax 801-483-6818

Request for Proposal (RFP) for the design and construction of the facility in local newspapers and on the SciQuest website: https://solutions.sciquest.com/apps/Router/SupplierLogin?CustOrg=StateOfUtah.

- **Sewer Utility Capital Improvement Plan (CIP) Budget – Five Year Projected Budget 2018-2022** –SLC Public Utilities' 2017/2018 Annual Budget includes planned expenditures for the current fiscal year and proposed budget for out years for the necessary capital projects at the plant. In addition, SLC Public Utilities has developed a capital financial plan to include the design and construction of the new facility. The financial plan includes bonding completed in 2017 and additional planned bonding in the next two to seven years for design and construction of the facility. In addition, SLC Public Utilities has communicated with the DWQ regarding potential funding sources through the State. The budget and process has been reviewed and adopted by the Public Utilities Advisory Committee (PUAC)[1] and Mayor of Salt Lake City as well as the Salt Lake City Council.

We thank you for your consideration of our application for variance and request that you contact us with any questions you may have.

Sincerely,

Laura Briefer
Director
Salt Lake City Corporation
Department of Public Utilities

cc: U.S. EPA, Region 8
Jesse A. Stewart, Jason Brown, Dale Christensen – SLCDPU
Patrick Leary, Salt Lake City
File

Attachments:

- Nutrient Project Pre-Design Report

[1] "The Salt Lake City Public Utilities Advisory Committee annually reviews the department's operation and maintenance budget and expenditures, examines the department's water and sewer system capital improvements program, recommends proposed legislation relating to water and sewer, and consults with the Mayor concerning water resources and sewage reclamation requirements. This committee assists the Public Utilities Director as much as possible to continue orderly development and operation of the public utilities system for the city." (http://www.slcgov.com/bc/boards-and-commissions-public-utilities-advisory-committee)

JACQUELINE M. BISKUPSKI
Mayor

**DEPARTMENT OF
PUBLIC UTILITIES**

CITY COUNCIL TRANSMITTAL

Patrick Leary, Chief of Staff

Date Received: 4/5/2019
Date sent to Council: 4/9/2019

TO: Salt Lake City Council
Charlie Luke, Chair

DATE: April 5, 2019

FROM: Laura Briefer, MPA
Director, Department of Public Utilities

SUBJECT: Request for City Council adoption of new water and sewer rate structures pursuant to the recommendations of the 2018 Comprehensive Water, Sewer, and Stormwater Rate Study, and in coordination with approval of Public Utilities' approved Fiscal Year 2019-2020 Budget

STAFF CONTACTS: Lisa Tarufelli, Finance Administrator, lisa.tarufelli@slcgov.com

Laura Briefer and Lisa Tarufelli will address the Council on this resolution.

DOCUMENT TYPE: Ordinance (**Exhibit A**)

RECOMMENDATION: Approve an ordinance that would adopt the recommended new water and sewer rate structures, in coordination with approval of Public Utilities' proposed Fiscal Year 2019-2020 Budget.

BUDGET IMPACT:
The rate structure design is revenue neutral and does not impact Public Utilities' budget.

BACKGROUND/DISCUSSION:
Public Utilities completed a Comprehensive Water, Sewer, and Stormwater Rate Study (Rate Study) in 2018. The executive summary of the Rate Study is included in **Exhibit B**. Public Utilities' objectives are to retain defensible rate structures and fees, while meeting other important rate objectives, such as sufficient revenue, rate stability, conservation, and equity. For this Rate Study, Public Utilities contracted with Raftelis, a recognized expert in water rate setting, and used industry-standard utility cost of service methodology as reflected in the American Water Works Association *Manual of Water Supply Practices M1, Principles of Water Rates, Fees, and Charges* and in the *Water Environment Federation Manual of Practice No. 27, Financing and Charges for Wastewater Systems.*

Water Rates

Three substantive changes are recommended to the existing water rate structure to address key objectives of conservation, affordability, rate stability, demand management, and interclass equity. These include the following structural changes:

- Change the system-wide cost of service rate structure (where volume rates by block are the same for all customers) to a customer class cost of service volume rate structure. This results in different volume rates for residential, commercial, and industrial classes that reflect the specific cost to provide service to each class. The Rate Advisory Committee (RAC) established for the Rate Study, and the Public Utilities Advisory Committee (PUAC) felt this rate structure meets goals related to equity. It also reduces the allocation of costs to residential classes, which helps to address essential use affordability for the residential class.
- Reduce the block four threshold from 70 ccf (hundred cubic feet) to 60 ccf for residential, duplex and triplex customer classes. Reduce the commercial, institutional, and industrial customer class block four threshold from 700% of annual winter consumption (AWC) to 600% of AWC. This addresses both conservation and demand management priorities through stronger water pricing signals.
- Retain the fixed charge by meter size, but modify the price ratio between the meter sizes to reflect the capacity potential of each meter size relative to a ¾" meter. This addresses goals related to equity and helps promote residential essential use affordability.

A cost of service analysis was also completed to establish a new secondary water irrigation rate. This is due to the development of secondary water systems operated at certain Salt Lake City golf courses. Public Utilities does not operate a secondary water irrigation system, so secondary water irrigation rates had not been previously established. To help address conservation and demand management goals, the design of the secondary irrigation water rate structure includes the same inclining block volume rate structure as the culinary water irrigation meter rate.

Sewer Rates

The RAC and PUAC recommended reducing the minimum sewer charge from four units to two units. The reduction in the minimum charge has an essential use affordability benefit, and also incentivizes indoor water use efficiency. The RAC and PUAC recommended retaining the existing customer class volumetric rate structure by volume and strength of wastewater flow, which helps address interclass equity goals. Rates for each class increase due to the updated cost of service analysis, and the reduction of the minimum sewer charge.

PUBLIC PROCESS:

A major component of the Rate Study was public engagement through the formation of the RAC. The RAC included citizen representatives, environmental advocacy organizations, commercial and industrial representatives, low-income advocacy groups, and numerous City departments and divisions. The RAC's two overarching purposes were to represent and communicate community values and provide input, including recommendations to the PUAC, Salt Lake City Mayor, and Council. Over six meetings during fall and winter 2017, the RAC developed rate structure alternatives based on the following ranked pricing objectives:

1) Conservation
2) Essential Use Affordability
3) Demand Management

4) Rate Stability
5) Interclass Equity

To meet these objectives, the RAC recommended modifications to the water and sewer rate structures. The RAC provided their recommendations to the PUAC at the January 8, 2018 meeting. During the January 25, 2018 PUAC meeting, committee members finalized their recommendation to the administration. These recommendations are presented in the Rate Study. Public Utilities then presented the Rate Study's recommended structural changes to the water and sewer rates to the City Council during the October 2nd, 2018 work session.

EXHIBITS:

Exhibit A: Proposed Salt Lake City Ordinance Adopting New Water and Sewer Rate Structures

Exhibit B: Executive Summary of the Salt Lake City Department of Public Utilities Comprehensive Water, Sewer, and Stormwater Rate Study

Exhibit A

Proposed Salt Lake City Ordinance Adopting New Water and Sewer Rate Structures

SALT LAKE CITY ORDINANCE
No. of ____ 2019

(Adopting New
Water and Sewer Rate Structures)

WHEREAS, Salt Lake City Department of Public Utilities convened a Rate Advisory Committee comprised of community representatives and stakeholders, and completed a Comprehensive Water, Sewer, and Stormwater Rate Study in 2018;

WHEREAS, as part of the 2018 Rate Study, the Rate Advisory Committee and the Public Utilities Advisory Committee recommended changes in the structure of water and sewer rates to meet primary objectives of conservation, essential water use affordability, water demand management, rate stability, and interclass equity;

WHEREAS, the key structural changes reflecting the above objectives include: (1) changing water rates from a system-wide cost of service basis to a class cost of service basis to meet equity and essential water use affordability goals; (2) reduction of the block four threshold to meet conservation and demand management goals; and (3) reduction of the sewer minimum charge to meet essential water use affordability goals;

WHEREAS, a new rate for secondary irrigation water was established, including an inclining rate block structure, to facilitate the use and conservation of secondary irrigation water at certain Salt Lake City parks and golf courses

WHEREAS, the Salt Lake City Consolidated Fee Schedule is proposed to be amended to incorporate new water and sewer rate structures in coordination with approval of Public Utilities' Fiscal Year 2019-2020 budget; and

WHEREAS, the Salt Lake City Council finds that good grounds exist for updating the calculation of water and sewer rates to better reflect the policies and priorities of the Council and are necessary, reasonable, and equitable.

NOW, THEREFORE, be it ordained by the City Council of Salt Lake City, Utah:

SECTION 1. The Salt Lake City Consolidated Fee Schedule shall be amended, in pertinent part, to reflect changes to water and sewer rate structures in coordination with approval of Public Utilities' Fiscal Year 2019-2020 Budget.

SECTION 2. This ordinance shall become effective on the date of its first publication.

Passed by the City Council of Salt Lake City, Utah this __ day of ______, 2019.

____

CHAIRPERSON

ATTEST:

____

CITY RECORDER

Transmitted to Mayor on ______________________________.

Mayor's Action: _________ Approved. ___________ Vetoed.

____

MAYOR

____

CITY RECORDER

APPROVED AS TO FORM

Date: 4-5-19

By: ER Vetta

(SEAL)

Bill No. _______ of 2019.

Published: ___________________

HB_ATTY-#76899-v1-Water_&_Sewer_Rate_Changes_Ordinance_4-5-2019_

Exhibit B

Executive Summary of the Salt Lake City Department of Public Utilities
Comprehensive Water, Sewer, and Stormwater Rate Study

SALT LAKE CITY DEPARTMENT OF PUBLIC UTILITIES

Comprehensive Water, Sewer, and Stormwater Rate Study

Draft-Final Report / July 17, 2018

* Executive Summary and Secondary water rate summary

RAFTELIS

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RAFTELIS

July 16, 2018

Ms. Laura Briefer
Director of Public Utilities
Salt Lake City Department of Public Utilities
1530 South West Temple
Salt Lake City, UT 84115

Subject: Comprehensive Water, Sewer, and Stormwater Rate Study

Dear Ms. Briefer,

Raftelis is pleased to provide this 2018 Water, Sewer and Stormwater Rate Study to the Salt Lake City Department of Public Utilities.

The Report details the revenue requirement, cost of service, and rate design analysis used to develop proposed fiscal year 2019 water, sewer, and stormwater rates. This study also includes a review and update to the City's miscellaneous water, sewer, and stormwater fees. As part of this study, the City convened a Rate Advisory Committee (RAC). The RAC was charged with reviewing and providing recommendations to Staff and the Public Utilities Advisory Board (PUAC) on water and sewer rate structure alternatives. The RAC's final recommendations are discussed in this report along with the PUAC recommendation to City Council.

We would like to thank you, Mr. Brad Stewart, Mr. Kurt Spjute and the members of the RAC for their assistance and support during this study. Questions regarding this report and the Study should be direct to Mr. Cristiano or me at the contact information below.

Sincerely,
RAFTELIS, INC.

Richard D. Giardina Todd Cristiano

Rick Giardina
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1. EXECUTIVE SUMMARY

1.1 Introduction

The Salt Lake City Department of Public Utilities (Department) retained Raftelis to conduct a water, sewer, stormwater rate and miscellaneous fees study. This study included the following:

- Engaging a Rate Advisory Committee (RAC) to provide input and feedback on water and sewer rate structure alternatives to the PUAC.
- Development of revenue requirements for the water, sewer and stormwater utilities for fiscal year (FY)19[1,2].
- Analysis of customer class cost of service for each utility.
- Design of cost-of-service rates and rate alternatives as recommended by the Rate Advisory Committee for FY19.
- Review and update the Department's miscellaneous fees for the water, sewer and stormwater utilities.

Raftelis applied industry standard methodologies supported by the American Water Works Association (AWWA) *Principles of Water, Rates, Fees, and Charges* M1 manual and the Water Environment Federation *Financing and Charges for Wastewater Systems Manual of Practice, No. 27* in the development and design of utility rates.

1.2 Study Findings and Recommendations

1.2.1 Rate Advisory Committee

Department Staff assembled a Rate Advisory Committee to participate in a review of the Department's water and sewer rate structures. Raftelis along with The Langdon Group and Department Staff, facilitated six meetings with the RAC. These meetings included, among other topics, the identification and ranking of pricing objectives, RAC input on alternative rate structures, and the RAC's recommended rate structure for FY19 implementation designed to meet the identified goals and objectives. The results were presented to the Department's Public Utilities Advisory Committee (PUAC) on January 25, 2018 for their review and recommendation to the Mayor and City Council.

Appendix A contains the *2018 Rate Advisory Committee* report summarizing the water and sewer rate structure recommendations. The RAC developed rate alternatives based on the following ranked pricing objectives:

1. Conservation
2. Essential use affordability
3. Demand management
4. Rate stability

[1] FY19 is the period from July 1, 2018 through June 30, 2019.
[2] The term 'FY19 Utility Presented' shown in this report are the adopted FY18 rates for water, sewer, and stormwater multiplied by the FY19 proposed revenue adjustment for each utility.

5. Interclass equity
6. Intraclass equity

To meet these objectives, the RAC recommended the following modifications to the water and sewer rate structures:

Water Rate Structure Recommended Alternatives

- Retain the fixed charge by meter size. Modify the price ratio between the meter sizes to reflect capacity potential of each meter size to a ¾" meter. This fixed charge modification is recommended regardless of which volumetric rate alternative is selected.
- The RAC recommended two water volumetric rate structure alternatives using a class-based cost-of-service rate for consideration to the PUAC. Table 1.1 compares the existing rate structure and the alternative rate structures. ***Many alternatives were considered by the RAC. For purposes of this report, the original "names" of the alternatives, as considered by the RAC, have been retained.***

    - ***Alternative #2: COS/Existing Structure Adjusted for COS.*** Retain the fixed-block rate structure for all residential customers and the average winter consumption (AWC)-based rate structure for commercial, institutional and industrial (CII) customers.
        - Reduce the block 4 threshold from 70 hundred cubic feet (ccf) to 60 ccf for the single residence, duplex, and triplex customer classes.
        - Reduce the CII block 4 threshold from 700% of AWC to 600% of AWC.
    - ***Alternative #3: COS/AWC All*** Modify the existing fixed-block structure for single residence, duplex, and triplex to an AWC-based 4 block rate structure, the same structure as CII.
        - Set the single residence, duplex, and triplex customer class block 4 threshold at 600% of AWC.
        - Reduce the CII customer class block 4 threshold from 700% of AWC to 600% of AWC.

Table 1.1: Water – Current and Proposed Rate Structure Alternatives
City and County

	Residential[1]			CII[2]	
Block	**FY19 Utility Presented**	**Alt. #2 COS/Existing**	**Alt. #3 COS/AWC All**	**FY19 Utility Presented**	**Alt. #2/ Alt. #3**
Winter Period (Nov-Mar)	Block 1 Rate for All Usage			Block 1 Rate for All Usage	
Summer Rate Structure (April through November)					
Block 1	0-10 ccf	0-10 ccf	0-AWC[3]	0-AWC	0-AWC
Block 2	11-30 ccf	11-30 ccf	AWC-300%	AWC-300%	AWC-300%
Block 3	31-70 ccf	31-60 ccf	300%-600%	300%-700%	300%-600%
Block 4	>70 ccf	>60 ccf	>600%	>700%	>600%

(1) Single residence block 1: 0 to 10 ccf
Duplex block 1: 0 to 13 ccf
Triplex block 1: 0 to 16 ccf
(2) Alternative #2 and Alternative #3 CII rate structures are the same.
(3) AWC = Average Winter Consumption. "AWC – 300%" means usage greater than a customer's AWC and less than or equal to 300% of the customer's AWC.

Sewer Rate Structure Recommended Alternatives

- Retain the customer class volumetric rate structure by volume and strength of wastewater flow for each alternative. Strength categories include biochemical oxygen demand (BOD) and total suspended solids (TSS). The two alternatives recommended are:
  - ***Alternative #1: No Minimum Charge.*** Eliminate the minimum charge. Customers are only charged for their AWC monthly flow.
  - ***Alternative #3: Reduced Minimum Charge.*** Reduce the minimum charge allowance from 4 ccf to 2 ccf. This reduces the minimum charge by approximately 43 .

Table 1.2 shows the existing sewer rate structure. The proposed structure remains unchanged from the existing.

Table 1.2: Sewer – FY19 Utility Presented and FY19 Proposed Raftelis Rate Structure

Class(1)	BOD Strength mg/l	TSS Strength mg/l	Flow $ per ccf	BOD $ per ccf	TSS $ per ccf
1	0 – 300	0 – 300	Applies to Existing and All Alternatives		
2	300 – 600	300 – 600	Same volume rate for all classes	Volume rate varies by BOD strength	Volume rate varies by TSS strength
3	600 – 900	600 – 900			
4	900 – 1,200	900 – 1,200			
5	1,200 – 1,500	1,200 – 1,500			
6	1,500 – 1,800	1,500 – 1,800			
7	>1,800	>1,800	*Special Rate by Customer*		

(1) Customers in classes 1 through 6 are billed monthly based on their average winter consumption (AWC) times the sum of the rates for flow, BOD, and TSS rates or a minimum charge whichever is greater. AWC is the average of water usage for the months November through March.

1.2.2 Public Utilities Advisory Committee

Staff presented the water and sewer alternatives at the PUAC's January 25, 2018 meeting. The PUAC recommended the following:

- Water:
  - Monthly fixed charge: Varies by meter size; capital costs by meter size varies by on meter capacity ratios.
  - Volume rate structure: Alternative #2: COS/Existing Structure Adjusted for COS
- Sewer: Alternative #3: Reduced Minimum Charge

The remainder of this report will show the proposed water and sewer rates under these alternatives. The term "proposed rates" refers to rates based on the recommended rate structure alternatives from the PUAC.

1.2.3 Water Rate Study

FY19 Proposed Raftelis water rates for were developed based on the following:

- A system-wide 4% revenue increase over FY18
- Customer class cost-of-service analysis
- Rate structure recommendations from the RAC and final recommendations from the PUAC

Fixed Charge

The proposed fixed charge varies by meter size. The fixed charge recovers the following costs: meter reading/billing, customer service, and a portion of capital costs. Meter reading, billing and customer service costs do not vary by meter size. Capital costs increase as meter size increases recognizing the additional costs to serve larger capacity customers. The capital cost differential by

meter size is based on the ratio of the maximum allowable flow capacity to a ¾" meter. Table 1.3 shows the FY19 Utility Presented and FY19 Proposed Raftelis fixed charges.

Table 1.3: Water – FY19 Utility Presented and FY19 Proposed Raftelis Fixed Charges[1]

Meter Size	FY19 Utility Presented	FY19 Proposed Raftelis	Change - $	Change - %
3/4"	$9.89	$8.84	($1.05)	(11%)
1"	9.89	11.56	1.67	17%
1 ½"	11.68	18.37	6.69	57%
2"	12.68	26.55	13.87	109%
3"	21.28	48.34	27.06	127%
4"	22.78	72.86	50.08	220%
6"	32.88	140.98	108.10	329%
8"	59.11	222.71	163.60	277%
10"	109.63	576.91	467.28	426%

(1) County fixed charges are 1.35 times City fixed charges.

Volume Rates

The proposed volume structures for residential and commercial (CII) retains the 4-block inclining structure. The irrigation volume structure retains the 3-block inclining structure. The residential rate structure is a fixed block structure while the commercial or CII class is an individualized structure. Residential rates include single residence, duplex, and triplex classes. CII includes commercial, industrial, and institutional customers. The CII structure's thresholds are based on each customer's average winter consumption (AWC). The irrigation structure retains the individualized target budget-based structure. The volume rates developed in this study are based on each class' cost of service. Table 1.4 shows the FY19 Utility Presented and FY19 Proposed Raftelis rates.

Table 1.4: Water – FY19 Utility Presented and FY19 Proposed Raftelis Residential Volume Rates(1) City Customers

Block	FY19 Utility Presented $ per ccf	FY19 Proposed Raftelis $ per ccf	Change - $	Change - %
RESIDENTIAL(2)				
		Winter (November - April)		
All Usage	$1.35	$1.30	($0.05)	(3.7%)
		Summer (April - October)		
1	$1.35	$1.30	($0.05)	(3.7%)
2	1.85	1.78	(0.07)	(3.8%)
3	2.57	2.47	(0.10)	(3.9%)
4	2.74	2.63	(0.11)	(4.0%)
COMMERCIAL				
		Winter (November - April)		
All Usage	$1.35	$1.42	$0.07	5.2%
		Summer (April - October)		
1	$1.35	$1.42	$0.07	5.2%
2	1.85	1.94	0.09	4.9%
3	2.57	2.70	0.13	5.1%
4	2.74	2.87	0.13	4.7%
IRRIGATION				
		Winter (November - April)		
All Usage	1.85	1.71	($0.14)	(7.6%)
		Summer (April - October)		
1	$1.85	1.71	(0.14)	(7.6%)
2	2.57	2.38	(0.19)	(7.4%)
3	2.74	2.53	(0.21)	(7.7%)

(1) County rates are 1.35 times City rates

(2) Includes single residence, duplex, and triplex. See Table 1.1 for the block thresholds for each class.

1.2.4 Sewer Rate Study

FY19 Proposed Raftelis sewer rates were developed based on the following:

- A system-wide 15% revenue increase
- Customer class cost-of-service analysis
- Rate structure recommendations from the RAC and final recommendations from the PUAC

The FY19 Proposed Raftelis sewer structure and rates retain the customer class by sewer strength classification. The customer classes are assessed unit charges ($ per ccf) for flow, BOD, and TSS. Table 1.5 summarizes the FY19 Utility Presented and FY19 Proposed Raftelis rate structure and rates.

Table 1.5: Sewer - Comparison of FY19 Utility Presented and FY19 Proposed Raftelis Rates

Class	BOD Strength mg/l	TSS Strength mg/l	FY19 Utility Presented(1)	FY19 Proposed Raftelis(2)	Change - $	Change - %
1	0 – 300	0 – 300	$3.05	$3.11	$0.06	2.0%
2	300 – 600	300 – 600	3.97	4.05	$0.08	2.0%
3	600 – 900	600 – 900	5.37	5.47	$0.10	1.9%
4	900 – 1,200	900 – 1,200	6.79	6.88	$0.09	1.3%
5	1,200 – 1,500	1,200 – 1,500	8.13	8.24	$0.11	1.4%
6	1,500 – 1,800	1,500 – 1,800	9.53	9.64	$0.11	1.2%
7	>1,800	>1,800		*Special Rate by Customer*		
Extra Strength Rates, $ per lb						
Chemical oxygen demand (COD)			$0.221	$0.356	$0.135	61.3%
Biochemical oxygen demand (BOD)			0.442	0.713	$0.271	61.3%
Total suspended solids (TSS)			0.264	0.451	$0.187	70.9%

(1) Customers in classes 1 through 6 are billed monthly based on their average winter consumption (AWC) times the sum of the flow rates for flow, BOD, and TSS or a minimum charge of $11.93 whichever is greater. AWC is the average of water usage for the months November through March.

(2) Customers in classes 1 through 6 are billed monthly based on their average winter consumption (AWC) times the sum of the flow rates for BOD, and TSS rates or a minimum charge of $6.82 whichever is greater. AWC is the average of water usage for the months November through March.

1.2.5 Stormwater Rate Study

Table 1.6 shows compares the FY19 Utility Presented and FY19 Proposed Raftelis stormwater fees. There is no change to the structure for FY19.

Table 1.6: Stormwater - Comparison of FY19 Utility Presented and FY19 Proposed Raftelis Rates

Customer Class	FY19 Utility Presented	FY19 Proposed Raftelis	Change $	Change %
1 or 2 Units < .25 acres	$4.94	$4.94	$0.00	0.0%
1 or 2 Units > .25	6.91	6.91	0.00	0.0%
3 or 4 Units	9.88	9.88	0.00	0.0%
Impervious Area Based	5.43	5.43	0.00	0.0%

1.2.6 Miscellaneous Fees Study

The Department assesses fees for various goods and services associated with providing water, sewer, and stormwater service. These goods and services directly benefit the customer requesting the service. As such, these costs are passed directly to the customer rather than through all rate payers. Raftelis reviewed selected fees from the water, sewer, and stormwater utilities, proposed updates and also evaluated new fees for the utilities. The existing and proposed fees can be found in Section 7 of this report. The fee categories reviewed include:

- Water connection fees
- Meter inspection and testing
- Fire hydrant maintenance fees
- Flat water charge – City and County Agencies
- Pressure testing
- Disconnection
- Plan review fees
- Sewer inspections/Industrial wastewater discharge permits
- Stormwater inspection fees
- Stormwater discharge permits

Table 3.12: Water – FY19 Typical Monthly Summer Bills - Single Residence City Customers

Usage ccf	FY19 Utility Presented	FY19 Proposed Raftelis	Change ($)	Change (%)	% of Summer Bills
0	$9.89	$8.84	($1.05)	(10.6%)	4.8%
5	16.64	15.34	(1.30)	(7.8%)	23.1%
10	23.39	21.84	(1.55)	(6.6%)	18.5%
20	41.89	39.64	(2.25)	(5.4%)	19.5%
30	60.39	57.44	(2.95)	(4.9%)	12.2%
40	86.09	82.14	(3.95)	(4.6%)	7.7%
50	111.79	106.84	(4.95)	(4.4%)	4.8%
60	137.49	131.54	(5.95)	(4.3%)	3.0%
70	163.19	157.84	(5.35)	(3.3%)	1.9%

3.12 Secondary Irrigation Water Rate

The Department requested a review and update of the secondary irrigation water rate for select golf courses and parks. This secondary water service is to the culinary irrigation water demands of select sites. The cost to provide this service includes an annual return on the Department's water resources cost and a water delivery cost.

The secondary irrigation water rate follows the same inclining block volume rate structure as the culinary irrigation-only meter rate. Each customer is provided a monthly budget based on the following factors: permeable area, historical evapotranspiration and standard watering practices. Water use within the budget is charged at a rate comparable to Block 2 of the standard residential rate (a block established to reflect reasonable outdoor use). Water use that exceeds the budget is charged in the higher blocks. It is hoped the structure provides incentive for wise use of water. Table 3.13 on the next page shows the summary calculation. Detailed calculations are contained in the appendix.

Table 3.13: Water - Secondary Irrigation Water Rate Calculation

Annual Costs	Units	Unit Cost $ per AF	Unit Cost $ per ccf
Annual return water resource costs	$5,194,331		
Reliable Water Supply, Acre-Feet (AF)	115,713		
Water resource unit cost, $ per AF		$44.89	$0.10335
Water delivery cost	$1,641,658		
Projected volume, AF	14,009		
Water delivery cost, $ per AF		$117.19	
Total, $ per AF		**$162.08**	**$0.37315**
Rate Structure, $ per AF			
Block 2		$162.08	37.3 cents
Block 3		307.95	71.4 cents
Block 4		623.01	$1.434

COUNCIL STAFF REPORT

CITY COUNCIL *of* SALT LAKE CITY

Item Schedule:
Briefing: 10/02/18
Public Hearing: n/a
Potential Action: n/a

TO: City Council Members

FROM: Sam Owen, Constituent Liaison / Policy Analyst

DATE: September 27, 2018

RE: Informational: Department of Public Utilities

2018 Comprehensive Water and Sewer Rate Study

GOAL OF THE BRIEFING

Provide information about the process and recommendations of the Comprehensive Water and Sewer Rate Study, especially with regard to changes that will impact customers. **A subsequent transmittal is expected to amend the City's Consolidated Fee Schedule (CFS) to include Rate Study recommendations and new rate structures.**

ISSUE AT-A-GLANCE

During the spring of 2017, the Department of Public Utilities indicated it would begin a public engagement process known as the Rate Advisory Committee (RAC) to solicit deliberate feedback on a number of proposed alternatives to the existing rate structure for water and sewer service. The Rate Study also involved an analysis of stormwater rates; no changes are currently recommended for this Utility. Public Utilities has a practice of conducting a rate study every five to six years.

The RAC met over the course of six meetings and forwarded recommendations to the Public Utilities Advisory Committee (PUAC), which forwarded its selections to the Administration. The Administration worked with financial consultants Raftelis to formalize these selections into a final report, which is the subject of this briefing. The RAC examined a number of alternatives and the present Rate Study models its recommendations from the alternatives that were selected by members of the RAC.

The final Raftelis report makes recommendations for changes to the rate structure for the City's water and sewer service. The final report also includes a number of recommendations for adjustments to existing miscellaneous

Public Utilities fees, as well as new miscellaneous fees, to be included as part of a subsequent proposal to amend the CFS.

Recommendations to the water and sewer rate structures would be revenue neutral, meaning the proposed changes would redistribute existing costs amongst the utilities' customer classes without generating additional funds compared to fiscal year 2019 adopted rates. Rate Study recommendations to miscellaneous fees would reflect actual costs of performing services related to the fees.

Changes to the rate structure in the Water Utility would result in slightly decreased bills for most residential customers, and increases in bills for commercial and industrial users, as well as institutional users. These changes would primarily impact water users connected through larger meter sizes and those consuming larger volumes of water. The changes in this rate structure are in part meant to reflect the essential use affordability priority identified by the RAC (Attachment 1, page 2). Because fixed charges for smaller meters would be reduced, along with reductions in charges for lower volumes of water use, essential water use would be anticipated to become more affordable with adoption of the recommended changes. Some institutional users will also be able to access and continue accessing secondary water for irrigation use which could result in savings; addition of the corresponding secondary water fee to the CFS would also increase transparency.

Changes to the rate structure in the Sewer Utility would result in similar impacts, with residential users experiencing some savings and more intensive users such as commercial and industrial customers experiencing bill increases. These adjustments in part reflect the costs of providing service to more intensive users of this utility. See ADDITIONAL & BACKGROUND INFORMATION for discussion.

No rate structure changes were recommended in the Stormwater Utility, the Street Lighting Utility was not included as part of the present study.

The water service rate differential for City and County customers is also addressed extensively by the Rate Study (See Attachment 1, PDF pages 33, 34 and 114; See also Attachment 2, County Water Rate Differential).

ATTACHMENTS

1. Administrative Transmittal: Comprehensive Water, Sewer and Stormwater Rate Study
2. Memorandum: County Water Rate Differential
3. RAC Stakeholder list

POLICY QUESTIONS

1. Based on the Raftelis Rate Study recommendations, rates would decrease slightly for some groups of users such as single residences, increase slightly for other groups, and increase significantly for still others.

    a. The Department performed extensive outreach over a period of several months to collect stakeholder feedback on various alternatives for new rate structures. Based on information gathered by the Department during this process, the Council may wish to ask, for which groups would the overall impacts of implementing the Rate Study recommendations be anticipated as the most noticeable or significant? Possible users experiencing significant impacts might include:

        i. Housing developers and residents, especially multi-family
        (as costs incurred through increased connection and service fees would likely be reflected in costs passed on to consumers)

        ii. Commercial developers and businesses utilizing new commercial space

iii. Industrial users, especially those with more treatment-intensive discharge, who would pay significantly more for both water service and sewer service

iv. Institutional users such as schools and churches, although impacts for these two customer classes would likely be primarily for water service rather than sewer as well.

b. Based on possible impacts to new construction such as multi-family housing and commercial properties, has the Department conducted outreach or otherwise looked into effects on the production of new supplies in these markets—i.e., if the rate structure and fees were implemented as recommended in the subject Rate Study, has the Department or have others explored likely impacts to the pace of new construction or housing values in Salt Lake City?

i. The Council may wish to explore this question in the context of new development—primarily commercial/industrial—slated for the City's Northwest Quadrant in coming years.

2. A recent proposal from the Administration seeks fee relief for developers of new multi-family housing when affordability requirements are met. How would that program affect the proposed changes, in terms of considering city-fees for developers as a package?

3. Miscellaneous fee recommendations: The Raftelis study includes recommended changes to the rate structures for sewer and water customers, as well as recommended changes to miscellaneous fees. New miscellaneous fees were studied and information provided based on the maximum cost of various services for which the miscellaneous fees are assessed, such as new connections, plan review and repeat inspections. The full cost of performing these services (enumerated in section 6 of the Raftelis report, Attachment 1 page 54) is not currently being offset by fee-for-service revenue, but is covered by other revenue sources (water sales and sewer charges).

Adoption of the recommended changes to miscellaneous fees would not be revenue neutral, i.e. adopting the fee adjustments as outlined in the Raftelis report would result in new revenue and consideration of adjustments to the fiscal year 2019 adopted budget for Public Utilities. By contrast, the rate structure recommendations are revenue neutral for fiscal year 2019. Therefore, considering the miscellaneous fee recommendations at this time would have both budget and policy impacts.

a. The Council may wish to discuss whether recommended changes to miscellaneous fees and the resulting budget impacts, might be incorporated in a future budget discussion, such as with the fiscal year 2020 budget proposal for Public Utilities, when a holistic proposal could be prepared.

b. Furthermore, the Council may wish to allow more time to review and discuss the proposed fee increases separate from the rate structure proposal. This would allow time to understand the overall budget options, and to identify specific values with regard to the proposed increases and possible ramifications of adjustments.

i. The Council may wish to request that Public Utilities returns with a proposal of a preferred fee increase scenario based on the Raftelis findings.

ii. One purpose might also be to highlight how adopting new, increased fees could offset future rate increases for customers of the Utilities.

iii. The Council may wish to request that Public Utilities recommend miscellaneous fee increases that the Department would like to be considered in the shorter-term, as part of a possible CFS amendment to adopt the proposed rate structure changes. See KEY CHANGES—Miscellaneous Fees for discussion.

KEY CHANGES—Water Utility

Table 1.3: Water – FY19 Utility Presented and FY19 Proposed Raftelis Fixed Charges[1]

Meter Size	FY19 Utility Presented	FY19 Proposed Raftelis	Change - $	Change - %
3/4"	$9.89	$8.84	($1.05)	(11%)
1"	9.89	11.56	1.67	17%
1 ½"	11.68	18.37	6.69	57%
2"	12.68	26.55	13.87	109%
3"	21.28	48.34	27.06	127%
4"	22.78	72.86	50.08	220%
6"	32.88	140.98	108.10	329%
8"	59.11	222.71	163.60	277%
10"	109.63	576.91	467.28	426%
(1) County fixed charges are 1.35 times City fixed charges.				

Table 1.3 above shows monthly fixed charges assessed to customers based on the size of the water meter installed to provide water service. The Raftelis proposed changes to the fixed charges are shown in the highlighted column.

Fixed charges for water service help recover costs related to the Utility's basic capacity to provide service (e.g. costs of existing infrastructure such as reservoirs, pipes, pump stations and so on).

Most residential customers fall in the ¾ - inch and 1-inch meter sizes.

CONVERSION TABLE

Acre foot (AF)	Key definition Hundreds of cubic feet (ccf)	Gallons (g)
0.0022956841	**1**	**748**
1	**435.6**	**325,828.8**

Table 1.4: Water – FY19 Utility Presented and FY19 Proposed Raftelis Residential Volume Rates(1) City Customers

Block	FY19 Utility Presented $ per ccf	FY19 Proposed Raftelis $ per ccf	Change - $	Change - %
RESIDENTIAL(2)				
Winter (November – April)				
All Usage	$1.35	$1.30	($0.05)	(3.7%)
Summer (April – October)				
1	$1.35	$1.30	($0.05)	(3.7%)
2	1.85	1.78	(0.07)	(3.8%)
3	2.57	2.47	(0.10)	(3.9%)
4	2.74	2.63	(0.11)	(4.0%)
COMMERCIAL				
Winter (November – April)				
All Usage	$1.35	$1.42	$0.07	5.2%
Summer (April – October)				
1	$1.35	$1.42	$0.07	5.2%
2	1.85	1.94	0.09	4.9%
3	2.57	2.70	0.13	5.1%
4	2.74	2.87	0.13	4.7%
IRRIGATION				
Winter (November – April)				
All Usage	1.85	1.71	($0.14)	(7.6%)
Summer (April – October)				
1	$1.85	1.71	(0.14)	(7.6%)
2	2.57	2.38	(0.19)	(7.4%)
3	2.74	2.53	(0.21)	(7.7%)

(1) County rates are 1.35 times City rates

(2) Includes single residence, duplex, and triplex. See Table 1.1 for the block thresholds for each class.

Table 1.4 above shows volume rates in the form of cost per "ccf," or cost per one hundred cubic feet. One ccf equals approximately 748 gallons. The Raftelis proposed changes would result in lower rates for residential users. The amount decrease in residential water rates is close to the amount the rates were increased in the fiscal year 2019 adopted City budget. Rates for irrigation users would also decrease, and rates for commercial users would increase. See ADDITIONAL AND BACKGROUND INFORMATION for discussion on the redistribution of costs that could be said to have differential impacts on user groups.

Table 3.9: Water – FY19 Utility Presented and Proposed Rate Structures

Block	Residential		CII		Irrigation(1)
	FY19 Utility Presented	FY19 Proposed Raftelis	FY19 Utility Presented	FY19 Proposed Raftelis	FY19 Utility Presented
Winter Period (Nov-Mar)	Block 1 Rate for All Usage		Block 1 Rate for All Usage		Block 1 Rate for All Usage
Summer Rate Structure (April through November)					
Block 1(2)	0-10 ccf	0-10 ccf	0-AWC(3)	0-AWC	0 – Target Budget
Block 2	11-30 ccf	11-30 ccf	AWC-300%	AWC-300%	Target Budget – 300% of Budget
Block 3	31-70 ccf	31-60 ccf	300%-700%	300%-600%	>300% of Target Budget
Block 4	>70 ccf	>60 ccf	>700%	>600%	

(1) No changes to the irrigation rate structure.
(2) Single residence block 1: 0 to 10 ccf
Duplex block 1: 0 to 13 ccf
Triplex Block 1: 0 to 16 ccf
(3) AWC = Average Winter Consumption. "AWC – 300%" means usage greater than a customer's AWC and less than or equal to 300% of the customer's AWC.

Table 3.9 above outlines Raftelis proposed changes to water volume structures. The only recommended change to this aspect of the water rate structure is lowering the threshold at which Block 4 "kicks in." This change would mean that each respective user's highest rate would become active at a lower level of use. Such an adjustment in how rates are assessed can promote conservation.

Table 3.12: Water – FY19 Typical Monthly Summer Bills - Single Residence City Customers

Usage ccf	FY19 Utility Presented	FY19 Proposed Raftelis	Change ($)	Change (%)	% of Summer Bills
0	$9.89	$8.84	($1.05)	(10.6%)	4.8%
5	16.64	15.34	(1.30)	(7.8%)	23.1%
10	23.39	21.84	(1.55)	(6.6%)	18.5%
20	41.89	39.64	(2.25)	(5.4%)	19.5%
30	60.39	57.44	(2.95)	(4.9%)	12.2%
40	86.09	82.14	(3.95)	(4.6%)	7.7%
50	111.79	106.84	(4.95)	(4.4%)	4.8%
60	137.49	131.54	(5.95)	(4.3%)	3.0%
70	163.19	157.84	(5.35)	(3.3%)	1.9%

Table 3.12 above outlines how Raftelis proposed changes to the rate structure would impact non-commercial residential water bills.

- 65.9% of these bills would be estimated to come in between about 5% and 10% percent lower with the proposed changes.
- 27.9% of these bills would be estimated to receive a reduction approximately equal to the last two years of water rate increases.

Table 3.13: Water - Secondary Irrigation Water Rate Calculation

Annual Costs	Units	Unit Cost $ per AF	Unit Cost $ per ccf
Annual return water resource costs	$5,194,331		
Reliable Water Supply, Acre-Feet (AF)	115,713		
Water resource unit cost, $ per AF		$44.89	$0.10335
Water delivery cost	$1,641,658		
Projected volume, AF	14,009		
Water delivery cost, $ per AF		$117.19	
Total, $ per AF		**$162.08**	**$0.37315**
Rate Structure, $ per AF			
Block 2		$162.08	37.3 cents
Block 3		307.95	71.4 cents
Block 4		623.01	$1.434

1 acre-foot (AF) equals 435.6 hundreds of cubic feet (ccf) and 325,828.8 gallons

Table 3.13 above outlines a new secondary irrigation water rate. Irrigation rates are assessed on the basis of a "target budget" for irrigation water use that is formulated using factors like the customer's permeable area,

historical evapotranspiration and standard watering practices. Water use that exceeds the budget is charged in higher blocks, just like water use for non-irrigation customers.

KEY CHANGES—Sewer Utility

Table 4.11: Sewer - Typical Monthly Bill Comparison

AWC	FY19 Utility Presented	FY19 Proposed Raftelis	Change ($)	Change (%)
0	$11.93	$6.82	($5.11)	(42.8%)
1	11.93	6.82	(5.11)	(42.8%)
2	11.93	6.82	(5.11)	(42.8%)
3	11.93	9.33	(2.60)	(21.8%)
4	12.20	12.44	0.24	2.0%
5	15.25	15.55	0.30	2.0%
6	18.30	18.66	0.36	2.0%
7	21.35	21.77	0.42	2.0%
8	24.40	24.88	0.48	2.0%
9	27.45	27.99	0.54	2.0%
10	30.50	31.10	0.60	2.0%

Table 4.9: Sewer - FY19 Utility Presented Rates[1]

Class	BOD Strength mg/l	TSS Strength mg/l	Flow $ per ccf	BOD $ per ccf	TSS $ per ccf	Total $ per ccf
1	0 – 300	0 – 300	$1.87	$0.78	$0.40	$3.05
2	300 – 600	300 – 600	1.87	1.28	0.82	3.97
3	600 – 900	600 – 900	1.87	2.11	1.39	5.37
4	900 – 1,200	900 – 1,200	1.87	3.02	1.90	6.79
5	1,200 – 1,500	1,200 – 1,500	1.87	3.80	2.46	8.13
6	1,500 – 1,800	1,500 – 1,800	1.87	4.68	2.98	9.53
7	>1,800	>1,800	*Special Rate by Customer*			
Extra Strength Rates, $ per lb						
Chemical oxygen demand (COD)			$0.221			
Biochemical oxygen demand (BOD)			0.442			
Total suspended solids (TSS)			0.264			

(1) Customers billed based on the average water usage for the months November through March (AWC) or a minimum charge is $11.93, whichever is greater.

Table 4.10: Sewer – FY19 Proposed Raftelis Rates[1]

Class	BOD Strength mg/l	TSS Strength mg/l	Flow $ per ccf	BOD $ per ccf	TSS $ per ccf	Total $ per ccf
1	0 – 300	0 – 300	$1.94	$0.68	$0.49	$3.11
2	300 – 600	300 – 600	1.94	1.11	1.00	4.05
3	600 – 900	600 – 900	1.94	1.83	1.70	5.47
4	900 – 1,200	900 – 1,200	1.94	2.62	2.32	6.88
5	1,200 – 1,500	1,200 – 1,500	1.94	3.29	3.01	8.24
6	1,500 – 1,800	1,500 – 1,800	1.94	4.05	3.65	9.64
7	>1,800	>1,800	*Special Rate by Customer*			
Extra Strength Rates, $ per lb						
Chemical oxygen demand (COD)			$0.280	$0.356		
Biochemical oxygen demand (BOD)			0.561	0.713		
Total suspended solids (TSS)			0.619	0.451		

(1) Customers in classes 1 through 6 are billed monthly based on their average winter consumption (AWC) times the sum of the rates for flow, BOD, and TSS or a minimum charge of $6.82 whichever is greater. AWC is the average of water usage for the months November through March.

Tables 4.11, 4.9 and 4.10 above show the difference between fiscal year 2019 adopted rates for sewer service and Raftelis proposed rates for sewer service.

- Table 4.11 is an example of the proposed decrease in the minimum fixed charge for sewer service, from $11.93/month to $6.82/month. This table shows typical monthly bills for discharge that is consistent with all single residential customers and many types of business such as offices. The bills escalate as the customer's average winter consumption (AWC) escalates. For customers with AWC costs lower than the fixed minimum charge, only this minimum charge is assessed. For customers with AWC costs higher than the fixed minimum charge, the minimum charge is not assessed in addition to costs based on the AWC—in other words, these customers are charged on the basis of AWC, without that AWC cost being layered on top of the minimum charge.

- Tables 4.9 and 4.10 show, respectively, fiscal year 2019 sewer rates based on strength of discharge and the Raftelis proposal for adjusting these rates.

    - Sewer rates are assessed on the basis of both flow volume and flow strength (flow strength is measured by the factors biological oxygen demand (BOD) and total dissolved solids (TSS)). These factors are ranked and then multiplied based on that ranking to determine costs for customers.

    - Cost per hundred cubic feet of flow increases with the Raftelis proposal, along with cost per hundred cubic feet of flow based on measurements of each BOD and TSS. The Raftelis proposal also includes cost increases for "Extra Strength Rates," and creates an additional set of factors by which these extra strength rates are assessed as well.

- Although some monthly bills would decrease based on the proposed decrease in the fixed minimum charge for sewer service, many monthly bills would increase based on the proposed adjustments that increase charges for flow, BOD and TSS. These increases in charges reflect cost of service and are revenue neutral based on the fiscal year 2019 adopted revenue figures.

KEY CHANGES—Miscellaneous Fees

The Raftelis findings involve recommendations for miscellaneous fee increases, intended to recoup the full cost of performing various services such as, and not limited to, those related to new connections, plan review and inspections. Costs for performing these services are currently not entirely offset by existing fees but are covered by other existing revenue sources.

If the recommended increases for miscellaneous fees were adopted en bloc as proposed in the Raftelis study, the result would not be revenue neutral. The Council may also wish for more detailed discussion with regard to the fee increases. As such, the Council may wish to request that Public Utilities include the recommendations for miscellaneous fees in its fiscal year 2020 budget proposal, perhaps broken down into one or more preferred scenarios. Doing so might also create the opportunity for ramifications of fee increases to be more fully explored, e.g. in terms of possible offsets to projected rate increases in coming years or in terms of impacts to the development and construction markets in coming years. These aspects of the study recommendations are also addressed in POLICY QUESTIONS.

As part of the current discussion and a possible subsequent amendment to the CFS, the Council may wish to consider Public Utilities' input on whether any fee increases would most need to be considered at this time. It has been indicated that one such recommendation is the suggested change to miscellaneous fees related to stormwater, outlined in table 6.8 below.

Some recommended changes might also entail offsets or balancing with regard to the General Fund. For example, changes related to fire hydrants and flat rates for water use would entail additional expenses for both the City Fire Department and the Unified Fire Authority. Other recommended changes might spur or compel other General Fund-related discussions such as those related to planning and permitting fees, and how costs for performing these services are or are not fully offset by corresponding charges.

Table 6.8: Stormwater Miscellaneous Fees

Fee Type	Existing Service Fee	Calculated Service Fee	Change $	Change %
Storm Water Inspection Fee	N/A	$132	132	New
Discharge into City Storm Water System – Includes 3 site visits	125	132	7	5.6%
Discharge into Stormwater System Re-inspection Fee	30	44	14	46.7%
Discharge into City Stormwater Registration Fee	20	44	24	120.0%

ADDITIONAL AND BACKGROUND INFORMATION

Service demand for the Utilities can be broken down into three main categories, also known as cost components: average day, maximum day and maximum hour.

- For every facility with the system used to provide service (sewer, water, stormwater, etc.), there is an underlying average demand, or uniform rate of usage, exerted on this facility based on what it takes to provide average, every day service for customers. This is the average day cost component.

- Certain facilities are operated and designed to meet the demand above the average day demand, i.e. to provide service for maximum day demand, which is extra-capacity or beyond just average. Costs associated with those facilities are allocated to both the average day and maximum day cost components.

- Similarly, other facilities are designed to meet demands in excess of maximum day requirements, known as maximum hour demand, or extra capacity designed to meet the systems' very highest and least frequent peaks of demand. Costs associated with these facilities are allocated to the average day, maximum day, and maximum hour cost components.

These types of service demand—average day, maximum day and maximum hour—constitute three of the five cost components to which attributes of the total system are allocated. The remaining two are meters & services and billing & collections. Costs are allocated differentially among users of the Water Utility based in part on how the facilities necessary to service the types of customers come into play.

For a simple example, heavy water users place demand on the system that necessitates the creation of facilities associated with meeting higher demand, such as storage and pumping infrastructure. Types of customers associated with heavier water use and thus higher demand on the system are also associated with the need for the infrastructure connected with meeting the higher demand they place on the system. In this way, costs are allocated among the classes of users such that costs of constructing, maintaining and operating infrastructure necessary to serve the respective classes are represented in the differential rates and fees to which various customers are subject.

Attachment 1, PDF page 93 provides one example of how these allocations are made on a percentage basis between five cost components for the Water Utility.

Similarly, allocations are also made among cost components of the Sewer Utility. These allocations correspond to costs assessed to sewer customers, again on the basis of connecting respective costs to provide service with charges assessed to respective classes of customers and the differential needs among the classes.

Attachment 1, PDF page 119 provides one example of how thse allocations are made on a percentage basis among the cost components for the Sewer Utility.

Similar connections between cost of service and charges assessed to recoup those costs underly the Raftelis proposed adjustments to the miscellaneous fees, as well.

APPENDIX

Table 4.7: Sewer – FY19 Proposed Raftelis Customer Class Cost of Service

BOD Class	TSS Class	Flow, ccf	BOD	TSS	Bills	Total
1	1	$16,599,021	$5,783,469	$4,169,093	$1,098,589	$27,650,171
1	2	43,678	15,218	22,489	0	81,386
1	3	19,895	6,932	17,364	0	44,191
1	7	562	196	1,051	0	1,808
2	1	651,072	372,264	163,527	1,678	1,188,540
2	2	1,130,381	646,318	582,020	5,975	2,364,693
2	3	0	0	0	0	0
2	4	97,359	55,667	116,153	941	270,121
3	1	187,736	176,947	47,153	246	412,081
3	2	614,217	578,916	316,253	491	1,509,878
3	3	27,650	26,061	24,133	491	78,335
3	4	1,037	977	1,237	41	3,292
4	1	47,383	63,920	11,901	41	123,245
4	2	545,789	736,280	281,020	1,193	1,564,282
4	3	842	1,136	735	0	2,714
4	4	9,872	13,317	11,777	0	34,967
5	1	89,625	152,133	22,511	0	264,268
5	2	2,245	3,811	1,156	82	7,294
5	4	1,620	2,750	1,933	0	6,303
5	5	713	1,210	1,101	0	3,024
6	1	95,414	199,466	23,965	0	318,844
6	2	18,945	39,604	9,754	0	68,303
6	4	1,058	2,213	1,263	0	4,534
7	1	42,512	327,616	10,784	41	380,952
7	2	54,738	486,111	28,466	0	569,315
7	3	50,614	542,061	44,635	41	637,351
7	4	6,675	60,952	8,043	0	75,670
7	5	778	10,111	1,213	0	12,102
Total		**$20,341,431**	**$10,305,656**	**$5,920,730**	**$1,109,849**	**$37,677,666**

Table 4.7 exhibits the proportions between cost of service and the number of customers to whom sewer service would be provided. For example, discharge-intensive customers that rank BOD class 7 and TSS class 3 would account for only 41 bills, but $637,351 in total cost of service. By these figures, the average monthly cost of serving these discharge-intensive customers would be $15,545.15 each, compared to an average cost of $25.17 serving BOD class 1 and TSS class 1 customers (largely residential). The significantly higher average monthly cost of service for serving discharge-intensive customers would reflect the cost of volume and treatment capacity that must be in place to serve these customers.




SALT LAKE CITY DEPARTMENT OF PUBLIC UTILITIES
RENEWABLE ENERGY STUDY CONTRACT No.51360066

SALT LAKE CITY RENEWABLE ENERGY PLAN

Energy Strategies, Sunrise Engineering, Utah Clean Energy, Carollo Engineers
Consulting Team

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1.0 EXECUTIVE SUMMARY

The Salt Lake City Department of Public Utilities (DPU) is striving to reduce its reliance on electricity generated from fossil fuels as it provides essential services to its customers. To achieve these objectives, DPU seeks to diversify its energy portfolio through the development of renewable resources on Salt Lake City and DPU owned and managed properties, including solar photovoltaic (PV) systems, hydroelectric, cogeneration, wind power, and wastewater heat recovery systems. To support this goal, DPU selected a consultant team to conduct a renewable energy feasibility assessment and create this renewable energy plan. The projects described in this report offer DPU the opportunity to harness the sun, wind, and water to generate clean electricity. By exploring these renewable energy projects now, DPU will be prepared to adapt to future trends and needs and to improve its operations city-wide.

DPU selected a consultant team headed by Energy Strategies and including Sunrise Engineering, Utah Clean Energy, and Carollo Engineers, collectively referred to as the "Consultant Team," to conduct the renewable energy feasibility assessment. The Consultant Team members have extensive experience helping private companies, institutions of higher education, and government agencies evaluate the technical, economic and regulatory feasibility of renewable energy and other clean energy technologies.

This study consisted of three sequential phases: a Preliminary Site Scoping Evaluation (Phase I), a Site-Specific Evaluation (Phase II), and a detailed evaluation of six potential project sites, including a regulatory assessment, an economic analysis, and recommendations for funding mechanisms and resources for each project (Phase III).

Phase I Preliminary Scoping Evaluation

DPU provided a list of 151 properties which were identified as potential sites for renewable energy projects. All 151 sites were screened and those found not to be suitable for a renewable energy project were eliminated. The remaining 42 sites were ranked using a screening matrix based on six criteria: suitability of the site for a renewable energy project, interconnection opportunities, zoning compatibility, permitting, and generation potential. Although not all 42 sites were ultimately reviewed in the Phase II analysis, many of these sites could support a viable renewable energy project. Combined, these sites could generate 18,779 megawatt-hours (MWh) of renewable energy.

Salt Lake City completed a 1 MW solar photovoltaic farm on a former landfill site at 1955 West 500 South in 2014. Existing incentives for solar, including a 30% federal tax credit which expires in 2016, can reduce the upfront expense of installing panels. DPU has the opportunity to install a solar farm more than three times the size of the landfill solar farm at the Terminal and Park Reservoirs.

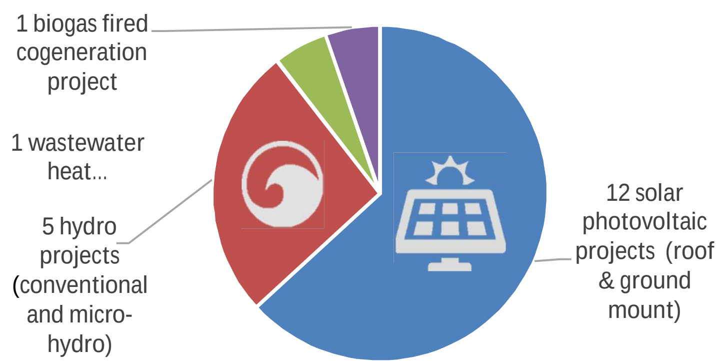
Phase II Site-Specific Evaluation

The results of the Phase I screening evaluation were presented to DPU for review and 19 sites were selected for more detailed evaluation in Phase II. These sites were chosen for further screening based on their score in Phase I screening matrix, because they provide opportunities for DPU to evaluate innovative technologies, or for both reasons. The 19 selected sites included:

- The 14 highest-scored sites from the Phase I analysis,
- 3 solar PV sites which received lower scores due to smaller generation potential but scored well in other categories,
- 2 projects that were not scored because further analysis was required: a wastewater heat recovery project at the West Temple trunkline and a cogeneration project at the Salt Lake City Water Reclamation Facility.

Combined, these projects could generate 13,690 megawatt hours of electricity, enough to offset approximately 44 percent of the electricity currently purchased by DPU from Rocky Mountain Power (RMP) and Murray City Power.

Figure 1-1. Projects Evaluated in Phase II



Conclusions and Recommendations of the Phase II Regulatory and Economic Analysis

From this group of 19 projects, DPU selected a representative cross-section of six projects to undergo a more detailed evaluation including regulatory assessment and economic analysis. A sixth project, wastewater heat recovery, was originally included in the Phase III detailed analysis. The wastewater heat recovery technology proved to be incompatible with the existing Central Heating Plant, so a demonstration project at the West Temple Trunkline was included in the analysis instead. The combined estimated overnight capital cost for the two solar photovoltaic (PV) and two hydroelectric projects is $14.8 million, and these four projects would be able to generate 6,287 MWh of electricity, and avoid 4,735 $MTCO_2e$ of greenhouse gas (GHG) emissions.

Table 1-1. Sites Included in Phase III Detailed Analysis

Site	Technology	Capacity (kW)	Benefit
Salt Lake City Water Reclamation Facility	Biogas Cogeneration	1,400	Use biogas to produce electricity; reduce the amount of biogas which is flared; offset purchases from RMP.
West Temple Trunkline	Wastewater Heat Recovery	N/A	Recover heat from wastewater; reduce natural gas consumption
15th East Reservoir[1]	Roof-mounted Solar PV	274	Produce electricity
Mountain Dell Dam	Hydroelectric	260	Produce electricity
Terminal & Park Reservoirs	Roof-mounted Solar PV	3,488	Produce electricity
Pressure Reducing Valve Station B11-R13	Hydroelectric Reverse-pump Turbine	190	Produce electricity

Regulatory Analysis:

The regulatory and financing assessment identified regulatory barriers and optimal rate schedules for each of the six Phase III sites in addition to various financing options available for each of the projects. While some of the rate options discussed are available now, others are currently under review by the Utah Public Service Commission (PSC). For those rates that are currently under review by the PSC, it is recommended that DPU continue to monitor the proceedings until new rates will be finalized.

A primary question asked regarding each potential site was whether electricity production from a renewable energy project at the site would exceed electricity usage at the site. Utah's net metering policy allows a facility to receive a credit for electricity produced on-site which can be used to offset purchases of electricity from the utility. However, electricity produced in excess of total annual usage is forfeited without compensation. If a renewable energy project produces more electricity than is

[1] Although a 274-kW solar installation was evaluated at the 15th East Reservoir, a smaller installation of approximately 25-kW could entirely offset electric usage on-site and potentially improve the economic viability of this project.

used on-site annually, the facility must contract to sell the excess electricity at wholesale rates or else forfeit it. Whether or not a facility is able to use the electricity on-site or must sell it obviously impacts the overall economics of the renewable energy project. Virtual net metering and selling excess electricity to the grid can help offset the capital investment in a renewable energy project.

While the Consultant Team recognizes it is DPU's preference to internally fund renewable energy projects using revenue from its utility operations, there are opportunities to leverage DPU's available funds with other funding sources to accelerate the deployment of City-owned renewable energy projects. All of the funding sources and financing mechanisms identified are viable options for lowering the upfront capital investment required by DPU. Moreover, from the perspective of DPU, lowering the capital investment will improve the economics of projects.

Economic Analysis:

Each project underwent an economic analysis which compared the projected cost of utility service at a given site to the potential savings DPU could capture by producing renewable energy. The economic value of each project was expressed as Net Present Value (NPV). First, each site was assessed using current regulatory and economic assumptions, including utility prices which are predicted to increase modestly over time. Next, two costs-of-carbon sensitivities were run to account for costs associated with future GHG regulations.[2] Assumed costs were \$25/MTCO$_2$e and \$50/MTCO$_2$e. Finally, one more sensitivity analysis was run assuming electricity generated by the pressure reducing valve project and the Terminal and Park Reservoirs solar PV project could be used to offset electricity consumed at other DPU facilities through virtual alternative net metering arrangement (which is not currently available in Utah). The results of the economic analysis are summarized in Table 1-2.

Summary and Conclusions

A detailed analysis of each of the six selected projects is provided in this report: table 9-1 provides an economic ranking of all six projects under several different regulatory scenarios, and table 9-2 ranks all six energy projects based on their potential to reduce DPU's greenhouse gas footprint. DPU must weigh several different factors when prioritizing amongst the projects presented in this report, including the economic analysis, the estimated avoided greenhouse gas emissions, the feasibility of each project, and other potential benefits of a project (such as increasing the visibility of Salt Lake City's energy initiatives). A summary of each project is provided below, including challenges associated with the project and recommendations for cost-effective completion, should DPU choose to pursue that project.

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[2] Federal agencies measure the potential impact of carbon emission regulations by assigning a cost to CO_2 emissions, represented as \$/megaton of carbon dioxide or carbon dioxide equivalent. This figure is used both to estimate the economic damages associated with an increase in carbon dioxide (CO_2) emissions and the value of a reduction in CO_2 emissions. The EPA has selected four Social Cost of Carbon values for use in regulatory analyses, representing various assumed discount rates. The most recent estimates for these values are available at http://www.epa.gov/climatechange/EPAactivities/economics/scc.html.

Table 1-2. Summary of Economic Analysis

Site	Technology	Rate Schedule	Overnight Capital Cost	Non-Fuel Operating Expense	Levelized Cost	Net Present Value compared to Cost of Utility Service ($Millions)		
			2014$ Millions	2014$ Millions	$ per MWh	$0 per $MTCO_2e$	$25 per $MTCO_2e$	$50 per $MTCO_2e$
Salt Lake City Water Reclamation Facility	Biogas Cogeneration (no BNR, no Nat. Gas)	Sch. 31 (9)	$0.00	$76.579	$25.60	($1.458)	($1.996)	($2.533)
	Biogas Cogeneration (BNR, Nat. Gas)	Sch.31 (9)	$0.00	$123.907	$61.50	$3.112	$3.468	$3.824
15th East Reservoir[3]	Roof-mounted Solar PV	Net metered	$0.920	$0.013	$153.50	$0.426	$0.314	$0.202
West Temple Trunkline	Wastewater Heat Recovery	N/A	$0.695	$0.000	N/A	$0.695	$0.584	$0.566
Mountain Dell Dam	Hydroelectric	Net metered	$1.551	$0.019	$92.00	$0.355	$0.064	($0.228)
Terminal & Park Reservoirs[3]	Roof-mounted Solar PV	Sch. 37	$11.292	$0.150	$139.50	$10.155	$8.699	$7.242
		Net metered			$139.50	$2.354	$0.898	($0.559)
Pressure Reducing Valve Station B11-R13	Hydroelectric Reverse-pump turbine	Sch. 37	$0.999	$0.015	$55.50	$0.585	$0.258	($0.068)
		Net metered			$55.50	($0.188)	($0.515)	($0.841)

Several projects rise to the top because they offer DPU attractive opportunities to reduce its environmental impact and the risk associated with carbon regulations while also lowering operations costs. If DPU were able to use electricity produced by one renewable energy project to offset electricity consumption at a different DPU site, either through virtual net metering or another, alternative net metering arrangement, savings associated with some projects would increase significantly. Although grants and financing mechanisms were not evaluated in the economic

[3] Costs and NPV are for a turnkey project without using a power purchase agreement (PPA) or other incentives. For solar PV projects, a PPA or prepaid lease structure would allow DPU to take advantage of a federal tax incentive through third-party ownership and could result in significant upfront cost reductions (up to 30percent). A PPA can be structured such that ownership reverts to DPU after tax advantages are fully utilized. In the case of the 15th East Reservoir, although a 274-kW solar installation was evaluated at the 15th East Reservoir, a smaller installation of approximately 25-kW could entirely offset electric usage on-site. Financial incentives to install a larger system are limited and the NPV would improve if the system were sized to meet the electricity needs of the on-site facility.

analysis, they would significantly reduce the overnight capital cost of several projects. For example, using a power purchase agreement (PPA) for solar photovoltaic installations allows DPU to realize savings of up to 30 percent due to a federal tax incentive for solar. Similar savings are achieved if DPU were to receive an incentive through the Utah Solar Incentive program. A portfolio of available financing options is described in Chapter 8, including the Blue Sky Grant Program, Qualified Energy Conservation Bonds, the U-Save Energy Program, the Utah Solar Incentive Program, and PPAs. Table C summarizes the challenges and recommendations associated with each project.

Salt Lake City Water Reclamation Facility

At the Salt Lake City Water Reclamation Facility, two cogeneration engines already exist and are used to convert excess biogas into clean energy. However, the current rate schedule at the facility does not allow for the sale of excess electricity to the grid, so the engines are not both operated at the same time for fear that they will produce excess energy. Switching to a rate schedule which does allow for the sale of excess electricity to the grid would allow DPU to operate both engines concurrently, burn more waste biogas, and produce more clean electricity to offset on-site electricity use. In the future, DPU may be required to convert to a Bio Nutrient Removal (BNR) process, which will reduce the amount of excess biogas production while also increasing electricity usage. Although the NPV of biogas cogeneration is negatively impacted by a BNR process, DPU could better utilize existing cogeneration engines with no infrastructure upgrades until required to switch to a BNR process.

The Salt Lake City Water Reclamation Facility uses cogeneration engines to convert waste biogas into clean electricity. By switching to a rate schedule that allows the Water Reclamation Facility to export excess power to the grid, the Facility could operate the existing cogeneration engines more frequently, make use of more waste biogas, and produce more clean energy.

Mountain Dell Dam

A hydroelectric turbine at the existing Mountain Dell Dam could be used to generate power to offset on-site electricity usage and poses no significant technical or regulatory challenges. If the future regulatory costs of carbon regulation are assumed to be \$50/$MTCO_2e$, a hydroelectric turbine at the Mountain Dell Dam has an attractive NPV.

B11-R13 Pressure Reducing Valve (PRV)

A micro-hydroelectric turbine at the B11-R13 PRV could produce electricity from the energy that is generated when the pressure in water pipelines is reduced before it is delivered to homes and

businesses. The NPV of this site is attractive if the site were able to virtually net meter and electricity produced at this PRV could be used to offset DPU load at other facilities. Virtual net metering is not currently available in Utah and there is no significant load at the PRV itself, so the electricity could instead be sold to the grid. The NPV of the project is still attractive even without virtual net metering when future carbon costs are assumed to be $50/MTCO_2e.

Terminal and Park Reservoirs

A large solar photovoltaic installation at these reservoirs could produce a significant amount of clean energy, however there is minimal DPU load on-site. If virtual net metering were available it would improve the NPV of this project significantly. Although leases and PPAs were not considered in this analysis, a lease or PPA would allow DPU to take advantage of a federal tax incentive through a third-party ownership structure and could result in significant upfront cost reductions (up to 30 percent). A PPA can be structured such that ownership reverts to DPU after tax advantages are fully utilized, and using a PPA would also significantly impact the assumed NPV. Notably, this project has the potential for the biggest environmental impact. Solar photovoltaic panels could produce enough electricity to offset 3,381 $MTCO_2e$ of emissions associated with utility electricity. This represents approximately 13 percent of the GHG emissions associated with DPU's consumption of purchased electricity and natural gas.

Reservoirs can be used to produce clean energy in several different ways. A hydroelectric turbine at the existing Mountain Dell Dam could be used to generate power and offset on-site electricity usage. Solar photovoltaic panels can be sited on top of enclosed reservoirs, such as the 15th East Reservoir and the Terminal and Park Reservoirs, so that otherwise un-utilized real estate can become a source of clean electricity.

15th East Reservoir

A 274-kW solar installation was evaluated at the 15th East Reservoir which would produce an average of 335,000 kWh of electricity each year. However, electricity meters located at this site report that the on-site load is only 70,000 kWh of electricity each year. A smaller 25-kW installation at this site could net meter and offset on-site electricity usage, however this option was not evaluated. Although DPU could build a 274-kW installation, as evaluated in this study, and contract to sell the excess electricity, a smaller net metered solar installation will offer a more attractive NPV. A lease or a PPA, which was not considered in this evaluation, would allow DPU to take advantage of a federal tax incentive through a third-party ownership structure and could result in upfront cost reductions of up to 30 percent.

Salt Lake City Wastewater Heat Recovery

Wastewater heat recovery at a site located adjacent to DPU's main office in Salt Lake City would utilize a heat exchanger to extract heat from wastewater flowing in the sewer trunkline along West Temple and provide space heating to DPU's main office. Although this project would allow DPU to reduce natural gas purchases, it would increase electricity usage. Even when the cost of carbon regulation is assumed to be \$50/MTCO_2e, the NPV of the cost of utility service of the wastewater heat recovery system is estimated to exceed the value of natural gas service provided by Questar over the 30 year-life of the project.

Table 1-3. Summary of Recommendations

Site	Technology	Summary	Challenges	Recommendations
Salt Lake City Water Reclamation Facility	Biogas Cogeneration	Best and most cost-effective opportunity for DPU to generate renewable electricity. A change in operations of engines would enable SLCWRF to burn additional biogas or NG and generate at least 50 percent more electric power.	• Federal water quality standards may require DPU to switch to a bio-nutrient removal (BNR) process in the future. • Existing tariff schedule does not allow generation to exceed load at the site.	• Make operational changes to increase capacity factor of engines and more effectively utilize biogas from site • Evaluate benefits of implementing a FOG program to increase biogas production • Evaluate whether SLCWRF can move to a different rate schedule that would enable it to sell excess electricity back to RMP.
	Biogas Cogeneration (BNR, NG)	Bio-nutrient removal process (BNR) may be required in the future and will have a negative impact on biogas production and make the existing cogeneration system uneconomic.	• Changing to a BNR process will use more electricity and produce less biogas as a byproduct	• If required to switch to BNR process, explore viability of supplementing biogas production by implementing a FOG program.
15th East Reservoir	Roof-mounted Solar PV	Excellent candidate for roof mounted solar PV technology. Limited load at the site makes a 274 kW system uneconomic however economics would improve significantly with a 25 kW system designed to meet site load.	• Minimal electricity usage on site • Unfavorable QF power purchase rates	• Additional analysis should be conducted by DPU to evaluate viability of installing smaller capacity system designed to meet load. • Explore economics of RMP grants and entering into a third party PPA or lease structure to significantly reduce up front capital cost and take full advantage of 30% federal tax credit
West Temple Trunkline	Wastewater Heat Recovery	At this site and given the technology configuration evaluated, the project is uneconomic and would offset natural gas consumption but increase electricity use.	• Low natural gas and electricity prices. • There are many more economically viable renewable energy projects at DPU owned sites.	• A technology demonstration should be considered if other partners, i.e. Questar or RMP, can be found to offset the upfront capital investment a technology demonstration project could be viable.
Mountain Dell Dam	Hydroelectric	An attractive site for renewable energy development because of the ease of interconnection, potential to offset 75% of load and it is eligible for net metering.		• This project is an excellent candidate to for development in the next 5 years. • Evaluate alternative financing options such as a PPA or lease to improve the economics
Terminal & Park Reservoirs	Roof-mounted Solar PV	Solar PV at this site has the potential to produce a large amount of renewable energy and offset GHG emissions.	• $11.3 million capital costs • Unfavorable QF power purchase rates and minimal site load make this project uneconomic	• Evaluate the use of a PPA or lease financing arrangement to take advantage of federal tax credits and apply to the Utah Solar Incentive Program to significantly improve the economics of the project. • Negotiate with RMP to allow this project to offset load at other DPU loads at full retail price.
Pressure Reducing Valve Station B11-R13	Hydroelectric Reverse-pump turbine	Significant RE generation potential. Cost effective when $50 price for carbon included in financial analysis. Attractive technology that can be used at numerous sites on SLC water delivery system.	• Most PRVs have minimal on-site load • Low QF power purchase terms	• Negotiate with RMP to allow this project to offset load at other DPU loads at full retail price. • Economics could be improved by adopting alternative financing approaches.

2.0 INTRODUCTION

2.1 Background

In early 2013, Salt Lake City introduced its *Sustainable Salt Lake – 2015 Plan*, a roadmap designed to enhance Salt Lake City's resiliency, vitality, and sustainability. The plan lays out key goals and strategies for Salt Lake City regarding renewable energy and GHG reductions, including a long-term goal to transform all Salt Lake City municipal facilities into "net zero" energy users. Short-term strategies include increasing renewable energy generation on Salt Lake City's municipal facilities to 2.5-MW and supporting the installation of 10-MW of photovoltaic solar on buildings in the Salt Lake metropolitan area, both by 2015. Reaching these targets will help Salt Lake City reach its 2015 climate change goals to reduce GHG emissions attributed to city buildings and fleet by 13 percent by 2015.

The Salt Lake City Department of Public Utilities (DPU) provides drinking water, wastewater treatment, and other essential services to residents and visitors of the Salt Lake Valley. In line with its mission to serve the Salt Lake Valley and also protect our environment, - DPU is striving to reduce its reliance on electricity generated from fossil fuels and diversify its energy portfolio through the development of renewable energy resources.

DPU has already taken steps towards incorporating more sustainable energy practices in its operations: a significant portion of DPU's water distribution system is designed to rely on gravity rather than electric pumps. Methane produced by anaerobic digesters at the Salt Lake City Water Reclamation Facility (SLCWRF) on average generates six million kWh of electricity per year. The electricity from this cogeneration system is used to power treatment plant operations, and preliminary assessments suggest there is excess digester capacity at the facility. In addition, DPU has examined other renewable energy options, including micro-hydroelectric opportunities in its water distribution system, and DPU and Salt Lake City properties that are potentially suitable for solar photovoltaic (PV) systems.

DPU is interested in expanding its efforts to develop renewable energy and reduce its reliance on electricity generated from fossil fuels as it provides these essential services to its service area and county residents. DPU owns and manages Pressure Reducing Valve (PRV) stations on its water distribution system, water rights, dam sites, a wastewater treatment plant that produces methane, covered reservoirs, building rooftops and other properties that could potentially support renewable energy projects. The access to these sites and the potential availability of wind, solar, biogas and hydroelectric resources presents an opportunity to develop new sources of clean energy, and that could position DPU as a leader in helping Salt Lake City achieve its renewable energy and GHG emissions goals.

In recognition of the opportunity to further develop its renewable energy potential at sites owned by Salt Lake City, DPU issued a Request for Qualifications (November 2013) and a Request for

Proposals (December 2013) Renewable Energy Study RFP No. 51360066, seeking the technical expertise and analysis needed to conduct an evaluation of existing and potential renewable energy projects, and to develop a Renewable Energy Plan for DPU.

2.2 Project Team

To support Salt Lake City's on-going efforts to diversify its energy portfolio and reduce its reliance on carbon-intensive fossil fuels, DPU selected a consultant team headed by Energy Strategies that included Sunrise Engineering, Utah Clean Energy, and Carollo Engineers (Consultant Team) to conduct the renewable energy feasibility assessment. The Consultant Team members have extensive experience helping private companies, institutions of higher education, and government agencies evaluate the technical, economic and regulatory feasibility of renewable energy and other clean energy technologies.

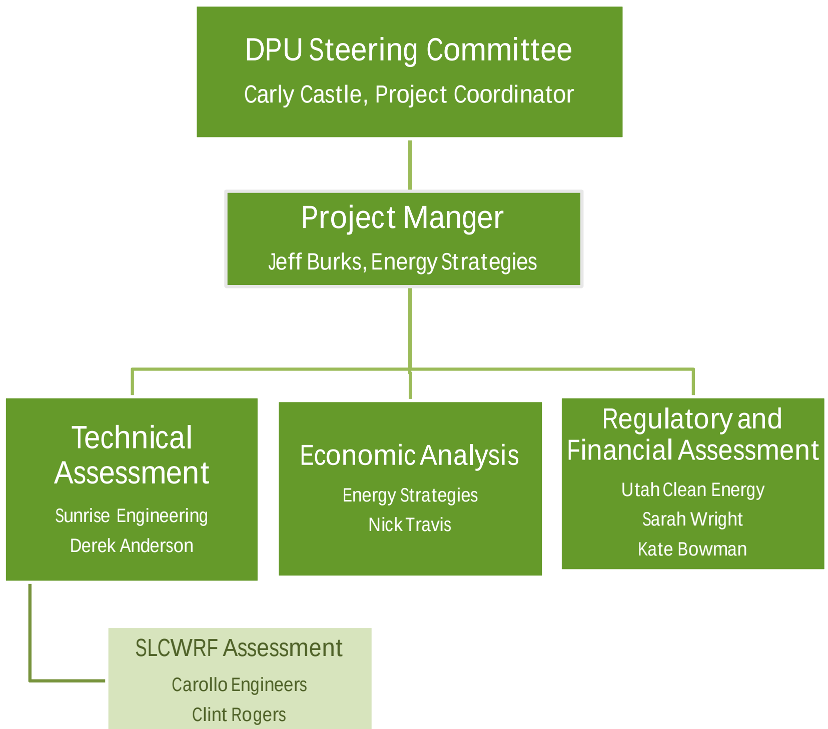
Energy Strategies L.L.C. has conducted over 100 technical, economic, and financial investment analyses and regulatory assessments of utility scale; and distributed renewable energy and co-generation systems for both public and private sector clients. Sunrise Engineering and Carollo Engineers have provided engineering assessments, design, and installation services for numerous small hydroelectric, micro-hydroelectric, biogas-to-energy, wind, and solar projects for both municipal governments and private developers. Utah Clean Energy has worked closely with Salt Lake City on their solar energy, energy efficiency, and climate policy initiatives since 2002, and provides integral experience and proven success within state regulatory and policy arenas to assist in the development and implementation of the Renewable Energy Plan.

In addition to the Consultant Team, Carly Castle, Special Projects Coordinator for DPU, and the DPU Steering Committee rounded out the project team that worked on the renewable energy development planning project. DPU Steering Committee members included:

- Jeff Niermeyer, Director
- Tom Ward, Deputy Director
- Laura Briefer, Deputy Directr
- Tyler Poulson, Program Manager, Division of Sustainability
- Jim Lewis, Finance Manager
- Mark Christensen, Financial Analyst
- Dale Christensen, Water Reclamation Manager
- Giles Demke, Wastewater Plant Maintenance Engineer
- Mark Stanley, Operations and Maintenance Superintendent
- Jesse Stewart, Water Quality Manager

The Consultant Team worked closely with Salt Lake City DPU personnel to ensure that all renewable energy options were identified and to implement a scope of work that would result in an actionable plan. If implemented, the plan will support Salt Lake City and DPU's goals to reduce dependence on fossil-generated electricity, increase the deployment of renewable energy, and reduce its GHG emissions.

Figure 2-2. Project Team



2.3 Overview of Approach

The evaluation of potential renewable energy projects at locations owned by Salt Lake City and DPU was divided into three sequential phases: a Phase I Preliminary Site Scoping Evaluation, a more detailed Phase II Site-Specific Evaluation, and a third phase evaluation where a cross section of six renewable energy projects evaluated in Phase II were selected to undergo a regulatory assessment and economic analysis.

The purpose of the Phase I Preliminary Scoping Evaluation was to conduct a high-level site assessment to identify, evaluate, and rank sites located at Salt Lake City properties and facilities based on the sites' ability to support a renewable energy project and generate power. The evaluation was designed to provide an initial, high-level screening of potential sites and provide DPU with a prioritized list of sites recommended for more detailed evaluation in Phase II.

The purpose of the Phase II assessment was to provide DPU with sufficient detail about siting characteristics, economic feasibility, regulatory pathways, and options for financing renewable energy projects to enable Salt Lake City to develop an implementation plan for project development. The

19 renewable energy projects selected from Phase I were screened through three sequential assessments in Phase II. The first, a detailed on-site assessment, was conducted by Sunrise Engineering (or by Carollo Engineers for the Salt Lake City Water Reclamation Facility). The on-site assessments recognized that even though a site may exhibit favorable generation potential in Phase I, environmental conditions, geological characteristics, interconnection access, and permitting and zoning limitations may preclude development of a renewable energy project at the location. An on-the-ground detailed assessment of 20 criteria was conducted at each site, including generation potential, interconnection and permitting requirements, zoning standards, and sustainability characteristics. Each site assigned a score for each assessment category using a 0 to 5 scale. Scorecard results were tabulated and input into a spreadsheet tool that scored each project on a weighted 100 point scale. These projects were then ranked according to score with 100 representing the best possible score.

Using the ranked results and input from the Consultant Team, the DPU Steering Committee selected a representative cross section of six projects from the 19 ranked projects taking into consideration technology, location, generation capacity, cost effectiveness, and project visibility. Six projects were selected for further evaluation, including a comprehensive evaluation of the regulatory feasibility and economic viability of each project.

Utah Clean Energy completed a regulatory assessment and identified financing options for each project. The regulatory assessment details current statutes, rules, and regulations that have the potential to impact the development, interconnection, and delivery of each renewable energy project evaluated.

Energy Strategies employed an annual cash flow model to evaluate the economic viability of each of the six renewable energy projects relative to a “Business as Usual” (BAU) scenario. The economic model provided an incremental analysis and comparison of both cash flow and GHG emissions savings associated with each proposed renewable energy project compared to the BAU case to establish the cost effectiveness and environmental benefits of each project.

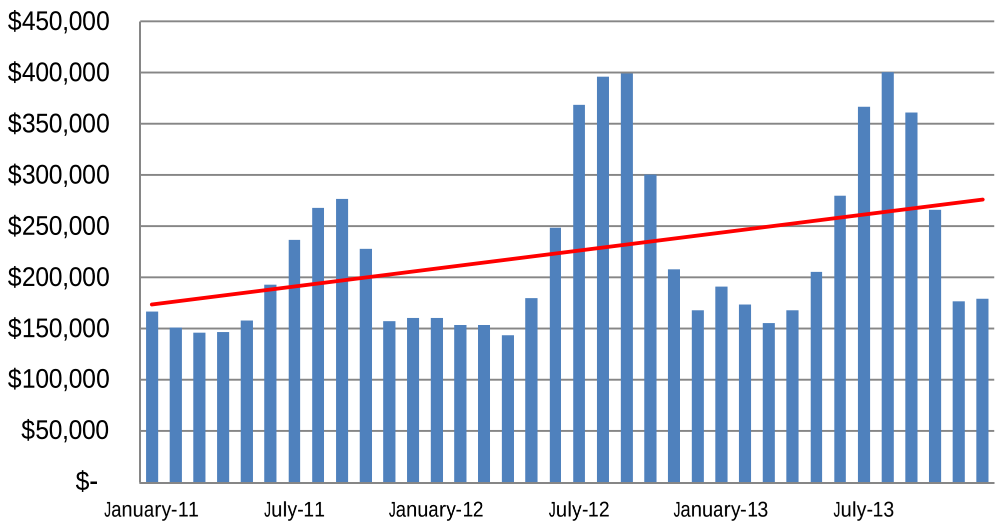
The results of the evaluation process employed by the Consultant Team were intended to provide DPU with sufficient detail on the 19 renewable energy projects evaluated in Phase II to allow for their subsequent development. A detailed description of methodologies for screening of renewable energy projects, detailed evaluations of site characteristics, economics, and regulatory options was provided in this report.

3.0 ENERGY USE PROFILE AND CO_2 EMISSIONS FOOTPRINT

Energy is one of the biggest economic and environmental costs of delivering water to taps and treating wastewater, and DPU is striving to reduce its reliance on coal and fossil fuels as it provides these essential services to its service area.

DPU supplies more than 349,000 customers in Salt Lake City and surrounding areas in Salt Lake County with culinary water, providing an average of 89.8 million gallons of water daily. Delivery of water to Salt Lake City service area residents depends on a complex network of free-flowing streams, reservoirs, aqueducts, water treatment plants, distribution systems, and water mains. DPU also collects and treats wastewater at the Salt Lake City Water Reclamation Facility (SLCWRF), a 56-million gallon wastewater treatment plant. Additionally, DPU manages the street lighting enterprise fund, which is responsible for maintaining and operating more than 15,000 street lights within Salt Lake City. To manage this vast system, DPU uses a significant amount of energy. In 2013, DPU consumed 32,320 MWh of electricity and burned 16,819 decatherms (DTH) of natural gas to operate the systems it manages. Figure 3-1 illustrates DPU's electricity and natural gas expenditures by month.

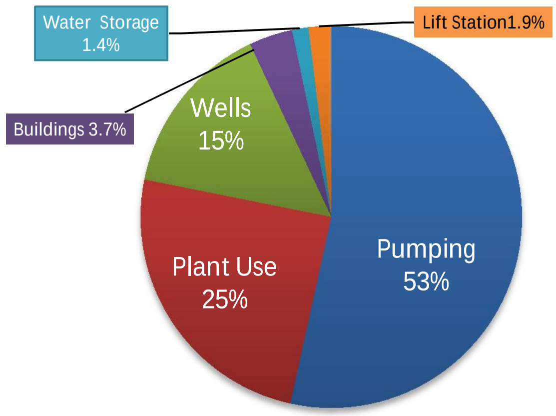
Figure 3-1. Electricity and Natural Gas Expenditures by Month



DPU is served by two electric utilities; Rocky Mountain Power (RMP) provides the vast majority of DPU's electricity, and Murray City Power provides power to a single pump station. The electricity provided by RMP has a significant environmental footprint in terms of water consumed and emissions of criteria pollutants and CO_2. Electric rate structures vary by facility.

In general, the majority of DPU's electricity use is from pumping water and wells to supply water to its customers. About 75 percent of DPU's electricity demand is assigned to wells and pumps, as illustrated in Figure 3-2.

Figure 3-2. Energy Consumed by End Use



3.1 Electricity

DPU has a peak energy demand in the summer months and its energy demand is correlated to its customers' water demand. Unfortunately, DPU's demand for electricity peaks during the summer (when the cost of electricity is higher), and electricity demand is lower in the winter (when the cost of electricity is lower). The monthly and yearly changing electricity demand can be seen in Figure 3-3.

In 2013, DPU spent $2.8 million dollars on electricity alone. DPU pays six different rates for electricity, which are based on RMP rate schedules for different types of facilities. The average price paid by DPU in 2013 was 8.7 cents per kWh, an increase from the average price in 2011 (7.9 cents/kWh) and in 2012 (8.2 cents/kWh). DPU paid approximately 10 percent more for electricity in 2013 than in 2011, as shown in Table 3-1. This change in the average price is based on a number

Figure 3-3. Electricity Consumption by Month 2011-2013

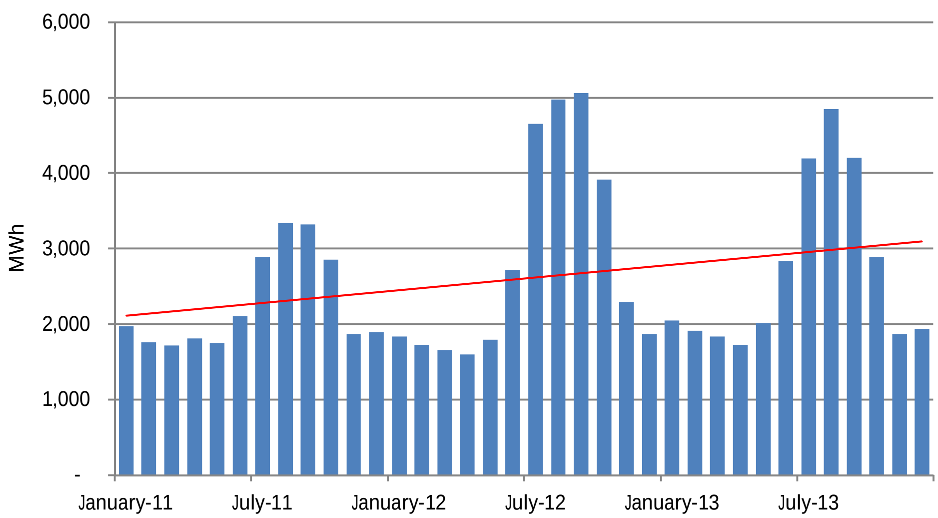


Table 3-1. DPU Electricity Use

Year	MWh	Average $/kWh	Dollars Spent	Emissions Tons CO_2[2]
2011	27,295	$0.079	$ 2,158,849	22,655
2012	34,085	$0.082	$ 2,774,725	28,291
2013	32,320	$0.087	$ 2,805,383	26,826

of factors, including higher RMP electricity rates and more purchases of electricity during summer peak energy times.

The challenge for DPU in future years will be to manage costs given a growing population and increasing electricity costs. For example, in 2011 DPU spent $2.1 million on electricity, however, in 2013 DPU spent $2.8 million on electricity (an increase of $700,000 or, 23 percent, in two years). This increase in energy expenditures can be seen in Figure 3-3, and the upward trend is illustrated by the red trend line.

3.2 Natural Gas

DPU's natural gas use is very different than its electricity use. Unlike electricity demand, DPU's natural gas usage peaks in the winter months to meet heating demand at plants and buildings. Questar Gas Company (Questar) supplies DPU with natural gas, and DPU's demand follows a typical pattern for natural gas with higher peaks in the winter and less demand in the summer.

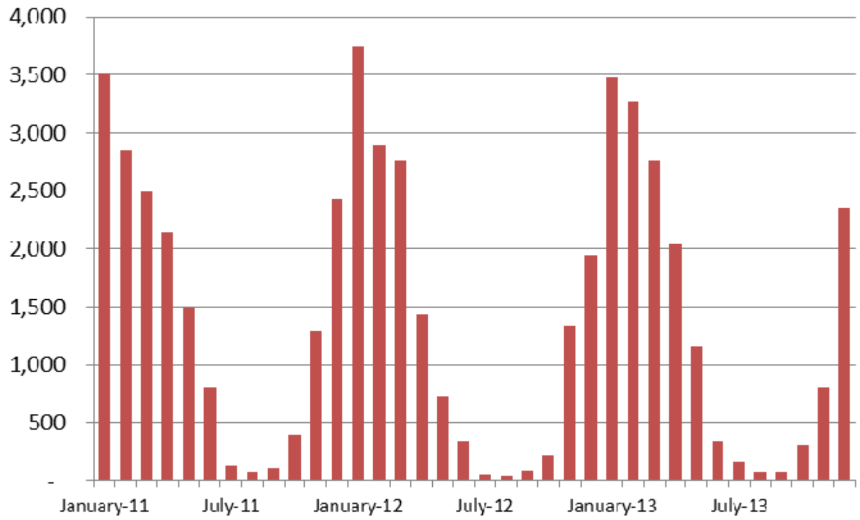
Unlike electricity, DPU's natural gas use and spending has been stable, ranging from $133,661 in 2011 to $123,941 in 2013, as shown in Table 3-2. Figure 3-4 illustrates natural gas consumption by month between 2011 and 2013.

Table 3-2. DPU Natural Gas Use

Year	Decatherm (DTH)	Average $/DTH	Dollars Spent	Emissions Tons CO_2
2011	17,740	$102	$133,661	1,048
2012	15,609	$83	$110,352	922
2013	16,819	$108	$123,941	994

2 Based on Salt Lake City's assumption that the power provided to them has an emission rate of 1.66lbsCO_2/kWh.

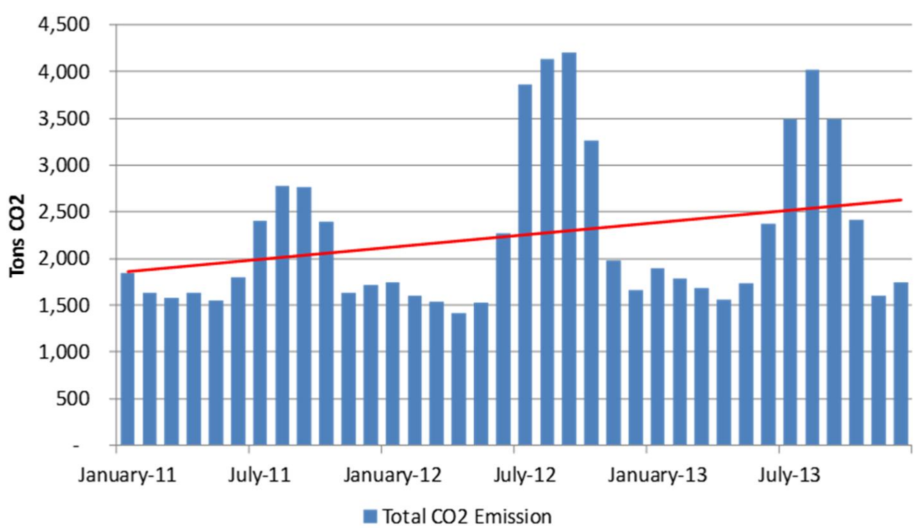
Figure 3-4. Natural Gas Consumption by Month 2011-2013 (DTh)



3.3 DPU Energy Use Carbon Footprint

Salt Lake City estimates there are 1.66 lbs/kWh of CO_2 emissions associated with its electricity use and 13.446 lbs/DTH carbon emission associated with burning natural gas. PacifiCorp, Rocky Mountain Power's parent company, produces 65 percent of its electricity from coal (based on PacifiCorp's 2013 Resource Plan).[3] DPU uses significantly more electricity than natural gas, which means DPU's CO_2 emissions are primarily due to electricity use. In 2013, the CO_2 emissions associated with DPU's consumption of electricity and natural gas totaled 27,820 tons. For the three years data was collected, CO_2 emissions ranged from a low of 23,703 tons in 2011 to a high of 29,213 tons the following year (Figure 3-5).

Figure 3-5. DPU Carbon Footprint from Energy Use 2011-2013



[3] PacifiCorp Integrated Resource Plan, https://www.rockymountainpower.net/about/irp.html.

4.0 PHASE I PRELIMINARY SCOPING EVALUATION

The objective of the Phase I Preliminary Scoping Evaluation was to identify, evaluate, and rank sites located at Salt Lake City properties and facilities which have the potential for renewable energy development. The evaluation was designed to organize 151 sites into a prioritized list based on the evaluation criteria, and then identify those sites which are recommended for evaluation in Phase II.

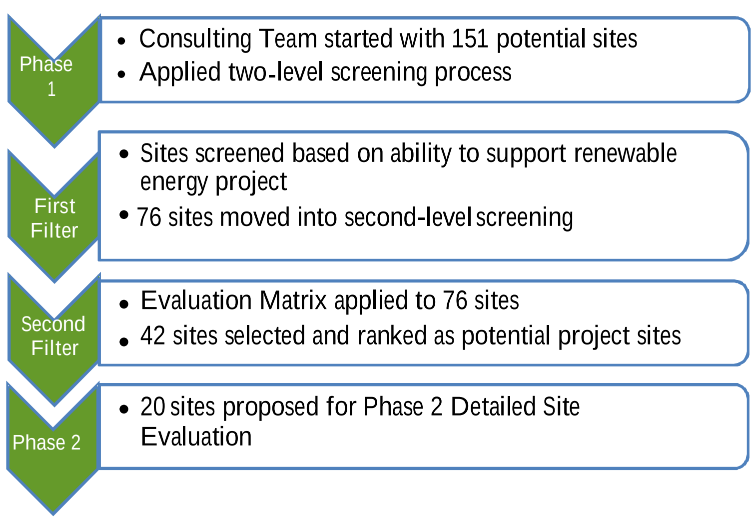
The Phase I evaluation included 50 potential solar photovoltaic (PV) sites (35 water storage facilities, 10 buildings, and 5 open land parcels); 95 potential hydroelectric sites (51 PRV sites, 44 water rights hydropower applications sites, 4 canal drop structures, and 1 pipeline); 2 potential wind power sites; 3 potential wastewater heat recovery sites; and 1 cogeneration site. Several of the water rights hydropower application sites overlapped with PRV sites and the evaluated pipeline sites.

4.1 Assessment Methodology

The 151 sites identified by DPU were put through a two-level screening evaluation. The first level filter assessed the ability of the site to support a renewable energy project and generate power. Sites identified as incapable of supporting a project were immediately eliminated from further consideration (see First Filter in Figure 4.1).

Sites were eliminated if they did not exhibit the necessary physical characteristics to viably support a renewable energy project and generate power. Sites identified as capable of supporting a project were funneled to the second-level filter, a matrix analysis of the project potential based on 6 criteria. Figure 4-1 illustrates the overall process.

Figure 4-1. Phase I Screening Methodology



The purpose of the matrix analysis was to objectively score and rank the remaining sites on a quantitative basis. Projects were ranked in order to select priority project sites which progressed to Phase II of the evaluation.

The matrix employed to conduct the second screening included three site evaluation criteria: annual generation potential, site characteristics, and environmental factors. Annual generation consists of the generation potential at a site. Site characteristics included the potential to offset existing site load, the potential to interconnect and the distance to power distribution infrastructure, and the approximate percentage of DPU load that could be potentially displaced at the site (if available). Environmental factors considered included perceived impact on the surrounding environment and local acceptance of a project. Table 4-1 illustrates the Phase I screening matrix criteria and scoring.

Table 4-1. Phase I Screening Matrix Criteria and Scoring

Category	Weighting Factor	5	4	3	2	1	0
Annual Generation							
Generation (kWh)	5	≥1,000,000	500,000-1,000,000	250,000-500,000	100,000-250,000	<100,000	
Site Characteristics							
Potential to Offset Existing DPU Load	2	Yes					No
Potential to Interconnect	3	Yes		Likely		Maybe	No
Proximity to Load & Distribution Infrastructure	4	≤500 ft	500-1000 ft	1000-1500 ft	1500-2000 ft	2000-2500 ft	2500+ ft
Percentage of DPU Load Displaced	1	81%-100%	61%-80%	41%-60%	21%-40%	1%-20%	<1%
Environmental Factors							
Environmental Impact	5	Negligible	Minor			Moderate	Major
Public Acceptance		100% Positive	90% Positive	80% Positive	70% Positive	60% Positive	50% Positive

Each criterion was given a rating of one through five, five being the highest, and weighted in such a way that if a site were to receive a rating of five for all criteria, it would accumulate a total score of 100 points.

4.2 Solar Photovoltaic Generation

Several types of solar photovoltaic systems were evaluated for this project, including ground-mounted systems of various sizes, small utility-scale systems, and distributed rooftop solar systems. Major factors considered in the design of these systems included shading, solar insolation (the average amount of solar radiation available in a given area and time), location, and mounting considerations. The advantage of the roof-mounted systems is that they require no additional land and can take advantage of existing DPU or City-owned buildings with flat rooftops. Land requirements for PV installations depend on many factors such as tracking technology, efficiency, and capacity factor. Common practice is to state land requirements in terms of acres per MW. Estimates from recent environmental impact studies done for large scale solar PV plants under development in California and Nevada suggest a requirement of between six and nine acres per MW is common.[4]

[4] NREL, "Land-Use Requirements for Solar Power Plants in the United States." http://www.nrel.gov/docs/fy13osti/56290.pdf

Fifty sites were evaluated for solar photovoltaic (PV) power potential. The sites consisted of 35 water storage facilities (reservoirs and tanks), 10 buildings or building complexes, and 5 open land parcels. Due to their proximity, Terminal Reservoir and Park Reservoir were combined as one site, as well as Granite Oaks Tank and Telford Reservoir, leaving 48 sites for evaluation. All of the solar PV sites exhibited the potential to generate electricity, so none of the solar PV sites were eliminated by the level one filter. Table 4-2 provides a summary of the 48 solar PV sites evaluated.

Table 4-2. Solar PV Potential Evaluation Summary

Site Name	Site Type	Capacity (kW)	Average Annual Generation (kWh)	On-Site or Adjacent Loads
Terminal Reservoirs/Park Reservoir	Water Tank/Res. - Roof Mount	1562	2,280,520	Wells 3580 E #4 & #5
Baskin Reservoir	Water Tank/Res. - Roof Mount	395	576,700	Bonneville PS
15th East Reservoir	Water Tank/Res. - Roof Mount	290	423,400	500 S Well & University PS
Military Reservoir	Water Tank/Res. - Roof Mount	256	373,760	Military PS
Victory Road Reservior	Water Tank/Res. - Roof Mount	248	362,080	
Wilson Reservoir	Water Tank/Res. - Roof Mount	241	351,860	Arlington Hills PS
Marcus Reservoir	Water Tank/Res. - Roof Mount	190	277,400	
Morris Reservoir	Water Tank/Res. - Roof Mount	176	256,960	North Bench PS
McEntire Reservoir	Water Tank/Res. - Roof Mount	142	207,320	
13th East Reservoir	Water Tank/Res. - Roof Mount	114	166,440	
Ensign Downs Lower Tank	Water Tank/Res. - Roof Mount	105	153,300	Ensign Downs PS
Tanner Reservoir	Water Tank/Res. - Roof Mount	67	97,820	Dyers Inn Well
Granite Oaks Tank/Telford Reservoir	Water Tank/Res. - Roof Mount	54	78,840	Granite Oaks PS
Tavaci Tank	Water Tank/Res. - Roof Mount	47	68,620	Tavici PS
Capital Hill Tanks	Water Tank/Res. - Roof Mount	45	65,700	
Mt Opympus Tanks	Water Tank/Res. - Roof Mount	45	65,700	Mount Olympus PS
East Bench Tanks	Water Tank/Res. - Roof Mount	38	55,480	Carrigan Cove PS
Ft Douglas Reservoir	Water Tank/Res. - Roof Mount	34	49,640	
Emigrattion Reservoir	Water Tank/Res. - Roof Mount	31	45,260	
White Reservoir	Water Tank/Res. - Roof Mount	30	43,800	
Perry' Hollow Tank	Water Tank/Res. - Roof Mount	28	40,880	
Teton Tanks	Water Tank/Res. - Roof Mount	15	21,900	
Eastwood Tanks	Water Tank/Res. - Roof Mount	14	20,440	Eastwood PS
Carrigan Cove Tank	Water Tank/Res. - Roof Mount	10	14,600	
Ensign Down Upper Tank	Water Tank/Res. - Roof Mount	9	13,140	
Canyon Cover Upper Tank	Water Tank/Res. - Roof Mount	9	13,140	
Canyon Cover Lower Tank	Water Tank/Res. - Roof Mount	9	13,140	
Ferguson Tank	Water Tank/Res. - Roof Mount	9	13,140	
Raineer Tank	Water Tank/Res. - Roof Mount	6	8,760	
North Bench Tank	Water Tank/Res. - Roof Mount	5	7,300	
Neff's Cayon Tank	Water Tank/Res. - Roof Mount	4	5,840	
Olympus Cove Tank	Water Tank/Res. - Roof Mount	2	2,920	
Millcreek Tank	Water Tank/Res. - Roof Mount	2	2,920	Lower Boundary PS
Boeing	Building - Roof Mount	733	1,070,180	Building Load
XPEDX	Building - Roof Mount	456	665,760	Building Load
Highland High School	Building - Roof Mount	333	486,180	Building Load
Roberts Restaurant and Adjacent Building	Building - Roof Mount	267	389,820	Building Load
410 N. Wright Brothers Drive	Building - Roof Mount	228	332,880	Building Load
Salt Lake City Sports Complex	Building - Roof Mount	187	273,020	Building Load
The Leonardo	Building - Roof Mount	91	132,860	Building Load
Sorenson Multicultural and Unity Fitness Center	Building - Roof Mount	58	84,680	Building Load
SLCDPU Buildings	Building - Roof Mount	57	83,220	Building Load
Horizonte Training Center	Building - Roof Mount	13	18,980	Building Load
South Lift	Open Parcel - Ground Mount	299	436,540	South Sewer LS
Smith & Loveless	Open Parcel - Ground Mount	85	124,100	Smith & Loveless and 4000 W Sewer LS
Concord Lift	Open Parcel - Ground Mount	79	115,340	Concord Sewer LS
6200 S. Well	Open Parcel - Ground Mount	63	91,980	6200 S Well & 6200 S Irrigation PS
Greenfield Village	Open Parcel - Ground Mount	51	74,460	Greenfield Village Well

For purposes of estimating capacity and generation it was estimated that 33.5 percent of a rectangular roof, or 30 percent of a circular roof, can be effectively used for installation of PV modules. The estimated capacity and average annual Alternating Current (AC) generation at each of the sites evaluated are summarized in Table 4-2.

Sites that were not adjacent to a DPU load and found to have an average annual generation less than 100,000 kWh were eliminated from further detailed evaluation of site characteristics and environmental factors in the matrix. Nineteen sites were eliminated based on these criteria, leaving 31 sites fully evaluated and ranked.

4.3 Hydroelectric Generation

Three hydroelectric generation technologies were evaluated for potential use at DPU and Salt Lake City sites: a conventional penstock-turbine configuration installed in conjunction with surface water impoundments; reaction turbines installed at Pressure Reducing Valve (PRV) stations used to control pressure in Salt Lake City's culinary water pipeline system; and micro-siphon hydroelectric generation systems that rely on the flow of surface waters in a canal or similar conveyance with a drop structure.

Ninety-five sites were evaluated for hydroelectric potential. The sites consisted of 51 PRVs, 44 water rights hydropower applications sites, four canal drop structures, and one pipeline. Several of the water rights hydropower application sites overlapped PRV sites and the evaluated pipeline site, which brought the total to 95 sites evaluated. Thirty-one of the PRV stations, 40 of the water rights hydropower application sites, and one of the canal drop structures were eliminated after the level one filter was applied. The estimated capacity and average annual generation at each of the 24 remaining sites potentially suitable for installation of hydroelectric technology are summarized in Table 4-3.

Sites that were not adjacent to a DPU load and that were found to have an average annual generation less than 100,000 kWh were eliminated from further detailed evaluation of site characteristics and environmental factors in the matrix. Eleven sites were eliminated based on these criteria, leaving 13 sites fully evaluated in the matrix.

4.4 Wind Power

Wind power is extracted from air flow using wind turbines to produce electric power. Wind power is very consistent from year to year but has significant variation over shorter time scales. As a renewable resource, wind is classified according to wind power classes, which are based on wind speed frequency distributions and air density. These classes range from Class 1 (the lowest) to Class 7 (the highest). In general, at a 50-meter height, wind power Class 4 or higher could be useful for generating wind power with turbines in the range of 250-kW to 750-kW.

Table 4-3. Hydroelectric Potential Evaluation Summary

Site Name	Site Type	Capacity (kW)	Average Annual Generation (kWh)	On-Site or Adjacent Loads
D74-DV1	PRV	359	1,310,352	
B35-R18	PRV	422	1,539,757	
B11-R13	PRV	292	1,064,622	
C41-R20	PRV	281	1,025,114	
B6-R73	PRV	266	970,091	
D69-R40	PRV	63	228,660	
A23-R5	PRV	59	216,797	
C1-R74	PRV	54	196,973	
F78-CR28	PRV	41	151,340	
G35-CR53	PRV	36	131,639	Private Well
E10-R55	PRV	24	88,569	
F60-CR47	PRV	19	70,807	
G38-CR57	PRV	17	62,052	7800 S PS
C12-R15	PRV	16	58,332	
D41-R35	PRV	13	46,610	
B36-R19	PRV	13	46,447	
D69-R39	PRV	11	38,378	
C41-R22	PRV	9	33,786	
F26-CR14	PRV	2	6,834	
F76-CR48	PRV	1	2,546	Dyers Inn Well
Mountain Dell Dam	Surface Water	410	2,370,536	Parley's WTP
Big Spill	Surface Water	15	65,520	On-site pump, lighting and gates
The Tower	Surface Water	8	32,256	On-site gates
2100 S. Plaza	Surface Water	2	8,784	On-site gates

For the evaluation of wind power potential, DPU requested the evaluation of two sites, Mountain Dell Reservoir and the adjacent water treatment plant. For the first level filter the Consultant Team utilized the U.S. Department of Energy and NREL 50-meter height wind resource map for Utah.[5] The map shows Wind Power Density (WPD) estimates at 50 meters (approximately 164 feet) above the ground and identifies wind resources that could be used for community-scale wind development using wind turbines at 50 to 60-meter hub height. The evaluation of the wind resource map indicates that the larger contiguous areas of good-to-excellent resources are located in western Utah, especially near the Raft River Mountains near the Idaho border, and in the area near Milford. Other good–to–excellent wind resource areas are located on the higher ridge crests throughout the state. In the Salt Lake Valley, the best wind resources (Class 2 to Class 4) are located at the mouths of Parley's, Millcreek, Big Cottonwood, and Little Cottonwood Canyons, and along Traverse Ridge.

The evaluation of the wind resource potential at the Mountain Dell Reservoir sites and the adjacent water treatment plant indicate these sites are located in Class 1 (the lowest) zone where the wind speed at the 50-meter height ranges from zero to 12.5 miles per hour. Accordingly, Mountain Dell

[5] Utah 50-Meter Wind Map, U.S. Department of Energy and National Renewable Energy Laboratory http://apps2.eere.energy.gov/wind/windexchange/maps_template.asp?stateab=ut.

Reservoir and the adjacent water treatment plant were not considered to be viable candidates for wind power generation and eliminated from consideration.

4.5 Wastewater Heat Recovery

Municipal wastewater is a promising source of energy which can be harnessed by using the discharge of water through sewer mains as a heat source and retrofitting lines with heat exchangers in conjunction with a larger heat pump. There are two different ways of recovering energy from wastewater: installation of a heat exchanger on the bed of the sewer or an external heat exchanger with an upstream pump and filter installation.

For the evaluation of wastewater heat recovery opportunities, DPU requested the technology be evaluated for its potential application at treated discharge water at the SLCWRF where it could be used for drying sludge. Additionally, the sewer main along 500 South near the Central Heating Plant, and the sewer main along West Temple next to the DPU campus were evaluated to supplement heating load at adjacent buildings.

In the Phase I screening it was determined that utilizing wastewater heat recovery at SLCWRF to increase the efficiency of drying sludge was not likely an economical or operationally feasible application of the technology. A demonstration project at the West Temple trunkline adjacent to the DPU campus was evaluated instead.

4.6 Cogeneration at SLCWRF

Carollo Engineers conducted an assessment of the SLCWRF to identify opportunities to expand or replace cogeneration technology at the site. A preliminary screening of the SLCWRF treatment plant was not undertaken because the site already supported a cogeneration system that used a renewable energy source, biogas, to generate electricity. The project was moved to the Phase II detailed site evaluation for further consideration. During Phase II, the Consultant Team evaluated optimizing the use of the plant’s biogas production with the existing cogeneration system in addition to new generation options.

4.7 Summary of Phase I Evaluation and Site Prioritization

The Phase I evaluation process conducted an initial screening of 151 sites. These included 50 sites for solar PV potential (35 water storage facilities, 10 buildings, and 5 open land parcels); 95 sites for hydroelectric potential (51 PRVs, 44 water rights hydropower applications sites, four canal drop structures and one pipeline); two sites for wind power potential; three sites for wastewater heat recovery potential; and one site for cogeneration potential. This preliminary screening and evaluation identified the technical generation potential of different renewable energy technologies at specific sites owned and operated by DPU. Of the original 151 sites identified, 42 sites were ultimately fully evaluated using the matrix spreadsheet.

The results show that sites with a score of 80 or higher generally had the ability to both generate at a higher capacity and offset either all or a portion of on-site DPU loads. The exceptions were four PRV sites that were not located adjacent to DPU loads but have the potential to generate at a higher capacity than other sites and possibly interconnect at a distribution line. Sites with mid-range scores between 60 and 79 were generally sites that either had a low generation potential but are located adjacent to a DPU load, or generate at a moderate capacity when compared to other sites and must interconnect to a distribution line nearby or potentially a short distance from the site. Sites with a low range score of less than 60 were generally sites with greater environmental impact potential or exhibited site constraints that may render the site more difficult to develop. Table 4-4 illustrates the results of the Phase I scoring. Appendix A provides the complete Phase I evaluation matrix input and results.

Table 4-4. Phase I Evaluation Scores

Ranking	Site Name	Technology	Site Type	Capacity (kW)	Annual Energy (kWh)	Total Points
1	Mountain Dell Dam	Hydroelectric	Surface Water	410	2,370,536	98
2	Terminal Reservoirs/Park Reservoir	Solar PV	Water Tank/Reservoir - Roof Mount	1,562	2,280,520	92
3	Morris Reservoir	Solar PV	Water Tank/Reservoir - Roof Mount	176	256,960	90
4	South Lift	Solar PV	Open Parcel - Ground Mount	299	436,540	90
5	15th East Reservoir	Solar PV	Water Tank/Reservoir - Roof Mount	290	423,400	86
6	Salt Lake City Sports Complex	Solar PV	Buildings - Roof Mount	187	273,020	86
39	Military Reservoir	Solar PV	Water Tank/Reservoir - Roof Mount	256	373,760	86
7	B35-R18	Hydroelectric	PRV	422	1,539,757	85
8	B11-R13	Hydroelectric	PRV	292	1,064,622	85
9	C41-R20	Hydroelectric	PRV	281	1,025,114	85
10	Victory Road Reservior	Solar PV	Water Tank/Reservoir - Roof Mount	248	362,080	85
11	Concord Lift	Solar PV	Open Parcel - Ground Mount	79	115,340	85
12	Baskin Reservoir	Solar PV	Water Tank/Reservoir - Roof Mount	395	576,700	84
13	Wilson Reservoir	Solar PV	Water Tank/Reservoir - Roof Mount	241	351,860	82
16	B6-R73	Hydroelectric	PRV	266	970,091	80
17	East Bench Tanks	Solar PV	Water Tank/Reservoir - Roof Mount	38	55,480	79
18	G35-CR53	Hydroelectric	PRV	36	131,639	78
14	6200 S. Well	Solar PV	Open Parcel - Ground Mount	63	91,980	76
19	Tanner Reservoir	Solar PV	Water Tank/Reservoir - Roof Mount	67	97,820	76
20	Granite Oaks Tank/Telford Reservoir	Solar PV	Water Tank/Reservoir - Roof Mount	54	78,840	76
21	Mt Opympus Tanks	Solar PV	Water Tank/Reservoir - Roof Mount	45	65,700	76
22	Eastwood Tanks	Solar PV	Water Tank/Reservoir - Roof Mount	14	20,440	76
23	Sorenson Multicultural and Unity Fitness Center	Solar PV	Buildings - Roof Mount	58	84,680	76
24	SLCDPU Buildings	Solar PV	Buildings - Roof Mount	57	83,220	76
25	Greenfield Village	Solar PV	Open Parcel - Ground Mount	51	74,460	76
26	Marcus Reservoir	Solar PV	Water Tank/Reservoir - Roof Mount	190	277,400	75
27	Capital Hill Tanks	Solar PV	Water Tank/Reservoir - Roof Mount	45	65,700	75
28	G38-CR57	Hydroelectric	PRV	17	62,052	74
29	D69-R40	Hydroelectric	PRV	63	228,660	70
30	C1-R74	Hydroelectric	PRV	54	196,973	70
31	A23-R5	Hydroelectric	PRV	59	216,797	67
32	Ensign Downs Lower Tank	Solar PV	Water Tank/Reservoir - Roof Mount	105	153,300	67
15	D74-DV1	Hydroelectric	PRV	359	1,310,352	65
33	Big Spill	Hydroelectric	Surface Water	15	65,520	60
34	Smith & Loveless	Solar PV	Open Parcel - Ground Mount	85	124,100	49
35	McEntire Reservoir	Solar PV	Water Tank/Reservoir - Roof Mount	142	207,320	45
36	13th East Reservoir	Solar PV	Water Tank/Reservoir - Roof Mount	114	166,440	45
37	F78-CR28	Hydroelectric	PRV	41	151,340	42
38	Tavaci Tank	Solar PV	Water Tank/Reservoir - Roof Mount	47	68,620	42
39	Salt Lake City Water Reclamation Facility	Cogeneration				
40	Salt Lake City Water Reclamation Facility	WWHR	Treated Wasetwater Effluent			
41	500 South Trunkline	WWHR	Wastewater Conveyance Main			
42	West Temple Trunkline	WWHR	Wastewater Conveyance Main			

As a result of the Phase I screening evaluation, 42 sites were ranked and presented to DPU for review. After consultation with the DPU Steering Committee, 19 sites were selected for more detailed evaluation in Phase II, as shown in Table 4-5.

Table 4-5. Renewable Energy Projects Selected for Phase II Evaluation

Site Name	Technology
Terminal and Park Reservoirs	Roof-mounted Solar PV
Morris Reservoir	Roof-mounted Solar PV
15th East Reservoir	Roof-mounted Solar PV
Victory Road Reservior	Roof-mounted Solar PV
Baskin Reservoir	Roof-mounted Solar PV
Wilson Reservoir	Roof-mounted Solar PV
Sorenson Fitness Center	Roof-mounted Solar PV
DPU Campus	Roof-mounted Solar PV
South Lift Station	Ground-mounted Solar PV
Concord Lift Station	Ground-mounted Solar PV
6200 S. Well	Ground-mounted Solar PV
Greenfield Village Well	Ground-mounted Solar PV
Mountain Dell Dam	Hydroelectric
PRV Station B35-R18	Hydroelectric
PRV Station B11-R13	Hydroelectric
PRV Station C41-R20	Hydroelectric
PRV Station D74-DV1	Hydroelectric
SLCWRF	Biogas Cogeneration
West Temple Trunkline	Wastewater Heat Recovery

5.0 PHASE II SITE-SPECIFIC EVALUATIONS

The Phase I evaluation was designed to filter potential renewable projects into a smaller set of projects that were subjected to a site-specific technical assessment. A total of 19 project sites (12 solar sites, five hydroelectric sites, one wastewater heat recovery site, and one cogeneration site) were evaluated as part of the Phase II Site-Specific Evaluations.

5.1 Overview of Methodology

The Phase II evaluation of the 19 renewable energy project sites was broken down into three sequential assessments. The first, a detailed site assessment, was conducted by Sunrise Engineering, Carollo Engineers, and Utah Clean Energy. The site evaluation was undertaken in recognition of the fact that even though a site may exhibit favorable generation potential in Phase I, structural considerations, environmental conditions, geological characteristics, interconnection access, and permitting and zoning limitations may preclude development of a renewable energy project at the location.

Each site was visited by team members and subjected to a detailed evaluation of its technical capability to support a renewable project. The evaluation criteria and scoring range were developed by the Consultant Team in consultation with the DPU Steering Committee.

The Consultant Team understood DPU was seeking both a quantitative and qualitative evaluation and comparative assessment of renewable energy project sites. A scoring and ranking system was created by the Consultant Team to allow for a consistent and objective ranking and comparative analysis of the diverse range of renewable energy technologies and sites. Assessment of the viability of each renewable energy project was conducted on the basis of six categories covering site compatibility, generation potential, interconnection and permitting requirements, zoning standards, and sustainability characteristics. Each category was scored on the basis of two to six criteria that were assigned a score using a 0 to 5 scale, with five being the highest score. Recognizing that some factors are more important for success than others, the scorecard results were tabulated and input into a spreadsheet tool that assigned a percentage weight to each criteria and each category, and calculated a final weighted score of 0 to 5 for each project. The weighted score for each site was then converted to a 100-point scale. Table 5-1 shows the detailed site evaluation criteria by evaluation category.

5.2 Solar PV

Twelve solar PV sites were selected for the Phase II detailed site evaluation. These project sites are provided in Table 5-2.

5.2.1 Detailed Site Evaluation

Each solar site was evaluated using a four step process: data collection and site analysis, preliminary PV array layout, capacity and generation estimation, and scoring and ranking of projects.

Table 5-1. Detailed Site Evaluation Criteria and Scoring

Evaluation Category	Criteria	Scoring Weight
Site	• Compatibility with the existing site use. • Compatibility with existing infrastructure. • Site access for construction and interconnection activities. • Obvious topographical, geologic, property, environmental constraints. • Potential public safety risk. • Conflicts with established land uses and potential of being a public nuisance.	30%
Interconnection	• Direct access to DPU load or the distribution system. • Complexity and costs of interconnection requirements.	15%
Zoning	• Extent to which the development of a renewable energy project would be compatible with existing zoning ordinances. • Whether those ordinances could potentially be changed if necessary.	15%
Permitting	• Required no. of permits. • Complexity of a permitting process.	10%
Generation	• Quality of the renewable energy resource. • Potential to increase DPU energy system resiliency to power outages and reliability. • Contribute to offsetting electricity load at the site. • Contribute to offsetting DPU's largest and most critical end use loads.	20%
Sustainability	• Contribution to meeting Salt Lake City's renewable energy goals. • Reducing reliance on fossil fuel generated electricity. • Contribute to meeting Salt Lake City's GHG goals. • Whether the project will enhance opportunities to educate Salt Lake City residents and improve public perception of DPU and Salt Lake City's commitment to clean energy and air. • Potential to enhance opportunities for local clean energy vendors and jobs. • Demonstrates leadership in the deployment of distributed renewable energy systems in Salt Lake City and help remove regulatory or policy barriers.	10%

Data collection consisted of a site visit to each of the 12 solar sites. Site assessments included the evaluation of site characteristics including current use of the site, structural design issues, available space, shading obstacles, consideration of potential interconnection options, zoning requirements, ease of permitting, a more detailed evaluation of generation potential strategies, and anecdotal information obtained from speaking with DPU employees.

Radiation data in the Salt Lake City area was also collected and a shading analysis was performed at each site using a Solar Pathfinder instrument, which takes into account the site latitude and how an obstruction may cause shading at a site over a calendar year.

Table 5-2. Solar PV Sites Evaluated in Phase II

Site Name	Site Type	Installation Type
Terminal and Park Reservoirs	Water Tank/Reservoir	Roof Mount
Morris Reservoir	Water Tank/Reservoir	Roof Mount
15th East Reservoir	Water Tank/Reservoir	Roof Mount
Victory Road Reservior	Water Tank/Reservoir	Roof Mount
Baskin Reservoir	Water Tank/Reservoir	Roof Mount
Wilson Reservoir	Water Tank/Reservoir	Roof Mount
Sorenson Fitness Center	Building	Roof Mount
DPU Campus	Building	Roof Mount
South Lift Station	Open Parcel	Ground Mount
Concord Lift Station	Open Parcel	Ground Mount
6200 S. Well	Open Parcel	Ground Mount
Greenfield Village Well	Open Parcel	Ground Mount

The interconnection assessment evaluated whether there was direct access to DPU loads or electrical distribution and the technical feasibility of interconnection. Each of the solar sites evaluated had a nearby or adjacent DPU service load and potential interconnection point to the electrical distribution system. It was also found that each of the potential sites would require either the upgrade or installation of a pad-mount transformer to facilitate a tie-in to the distribution system.

Five of the solar sites would require a zoning ordinance change in order to install solar PV arrays (Baskin Reservoir, Concord Lift Station, Morris Reservoir, Terminal and Park Reservoirs, Victory Road Reservoir), however, it is not anticipated that an ordinance change would result in a lengthy protracted process. The other seven sites are already zoned for solar array installation.

It is anticipated that a conditional use permit would be required for each site and would be relatively simple to obtain for at least 10 of the 12 potential sites. Two of the sites (Concord Lift Station and Wilson Reservoir) may be more difficult to permit due to adjacent property owner access issues (Concord Lift Station) and the potential to impair scenic vistas (Wilson Reservoir).

A preliminary PV array layout was developed to maximize the number of PV modules that may reasonably be installed at each site. Based on the PV array layout, the potential first year of electricity generation for each site was estimated. The accumulative output for 25 years was also estimated using a module degradation rate of 0.6 percent per year. Table 5-3 provides a summary of the capacity and generation estimates at each site.

5.2.2 Scoring and Ranking of Solar PV Projects

Scores for each of the 12 solar sites were developed following the evaluation of each site. Based on the results of the on-site evaluation of siting characteristics, generation potential, ease of interconnection with load and/or the grid, permitting and zoning, and consideration of additional

sustainability, criteria scores for each solar site were tabulated and ranked relative to the other potential solar PV projects. Table 5-4 provides a summary of the scoring and ranking of each site.

Table 5-3. Solar PV Capacity and Generation Estimates

Site Name	Number of Panels	AC Capacity (kW)	Average Annual Generation (kWh)
Terminal & Park Reservoirs	15,853	3,488	4,489,218
Morris Reservoir	1,244	274	360,918
15th East Reservoir	1,244	274	334,918
Victory Road Reservoir	2,029	446	556,634
Baskin Reservoir	1,908	420	514,706
Wilson Reservoir	1,161	255	335,868
Sorensen Fitness Center			
DPU Campus			
South Lift Station	1,312	289	380,608
Concord Lift Station	288	63	75,461
6200 South Well	220	48	49,644
Greenfield Village Well			

Table 5-4. Solar PV Project Scoring and Ranking

Project Site	Technology	Capacity (kW)	Score
Sorenson Fitness Center	Building Rooftop PV	NA	85.6
DPU Campus	Building Rooftop PV	NA	85.4
15th East Reservoir	Roof Mounted PV	274	84.6
South Lift Station	Ground Mounted PV	289	83.3
Wilson Reservoir	Roof Mounted PV	255	71.9
6200 S. Well	Ground Mounted PV	48	68.6
Greenfield Village Well	Ground Mounted PV	NA	67.3
Morris Reservoir	Roof Mounted PV	274	67.2
Victory Road Reservoir	Roof Mounted PV	446	66.3
Terminal & Park Reservoirs	Roof Mounted PV	3,488	65.0
Baskin Reservoir	Roof Mounted PV	420	62.6
Concord Lift	Ground Mounted PV	63	50.6

5.3 Hydroelectric Generation

Five of the 95 hydroelectric sites evaluated in Phase I were selected for a more detailed Phase II evaluation. The selected sites include one conventional hydroelectric site at Mountain Dell Dam just upstream of the Parley's Water Treatment Plant, and four PRV sites located within the water distribution system, as shown in Table 5-5.

Table 5-5. Hydroelectric Sites Evaluated in Phase II

Site Name	Site Type
Mountain Dell Dam	Surface Water
PRV Station B35-R18	Pressure Reducing Valve
PRV Station B11-R13	Pressure Reducing Valve
PRV Station C41-R20	Pressure Reducing Valve
PRV Station D74-DV1	Pressure Reducing Valve

5.3.1 Detailed Site Evaluation

Evaluation of each hydroelectric site was accomplished in three steps: collection and analysis of flow data, capacity and generation estimation, and scoring and ranking of projects.

Data collection consisted of a site visit to each of the five hydroelectric sites. Site assessments included the evaluation of physical site characteristics (site usage, available space), consideration of potential interconnection strategies, and anecdotal information obtained from speaking with DPU employees. Relevant historical flow data was also provided by DPU for each site. The historical flow data was utilized to develop a flow duration curve providing data on the probability of flow magnitudes based on historical data.

The technical feasibility of interconnection was evaluated at each potential hydroelectric site whether there was direct access to DPU loads or to electrical distribution lines. The proximity and ease of interconnection was preliminarily evaluated including the identification of additional infrastructure that may be necessary. Only the Mountain Dell Dam site had an adjacent DPU service load (Parley's Water Treatment Plant). PRV stations B11-R13, B35-R18, and C41-R20 are each located adjacent to a potential interconnection point to the electrical distribution system. While there are high voltage transmission lines located adjacent to D74-DV1 (adjacent to the I-80 and I-215 interchange), there is no nearby access to the three-phase distribution system. Therefore, construction of a three-phase distribution line would be required to develop hydroelectric power at D74-DV1. Each of the potential sites would require installation of a pad-mount transformer to facilitate a tie-in to the distribution system.

Zoning ordinances in the vicinity of the PRV sites currently allow for utility buildings or structures and transmission wire lines, pipes, or poles. Therefore, it is not anticipated that an ordinance change would be required.

It is anticipated that DPU would be required to either file a notice of intent to construct a qualifying conduit hydropower facility (QCHF), or complete the Conduit Exemption process with the Federal Energy Regulatory Commission (FERC) to complete a project at the Mountain Dell Dam site. For the PRV station sites (B11-R13, B35-R18, and D74-DV1) filing a notice of intent to construct a QCHF with FERC would be required.

Based on a more detailed analysis of flow and head conditions at each hydroelectric site, the capacity and average annual generation at each site was estimated and provided in Table 5-6.

Table 5-6. Hydroelectric Capacity and Generation Estimates

Site Name	Capacity (kW)	Average Annual Generation (kWh)
Mountain Dell Dam	260	690,000
PRV Station B35-R18	220	1,145,000
PRV Station B11-R13	190	773,000
PRV Station C41-R20	170	872,000
PRV Station D74-DV1	300	700,000

The most technically feasible hydroelectric development at Mountain Dell Dam site would be a facility installed upstream of the Parley's Water Treatment Plant at the toe of Mountain Dell Dam, which utilizes the flow and head from Mountain Dell Dam only. Based on our assessment of flow data provided for the Little Dell site and our evaluation of the pre-design report prepared by Alpha Engineering and RB&G Engineering, Inc. (2014), the Consultant Team concluded the results of the report were not reasonable or practical. If DPU still wishes to operate a hydroelectric facility utilizing the head and flow from the Little Dell Bypass, a more detailed evaluation of the hydrology conditions is warranted.

Each of the four PRV stations are technically feasible but would require expansion or reconstruction of the existing vaults to accommodate hydroelectric equipment and controls. It would also be necessary to provide measures to ensure uninterrupted flow to the distribution system in the event the hydroelectric equipment is offline.

In the case of PRV stations B11-R13 and D74-DV1, each vault could be expanded or reconstructed with minimal or no disturbance to adjacent traffic conditions. However, both B35-R18 and C41-R20 are located in vaults directly beneath the roadway. While sites D74-DV1, B35-R18, and C41-R20 have flatter topography directly adjacent to the vault, site B11-R13 is located along a slope which could require significant slope stabilization measures during construction of a vault expansion.

If DPU desires to develop the hydroelectric potential at the PRV stations, it is recommended the sites be metered to collect flow data for at least a year to understand how the flow data from the model may vary from what is actually occurring on-site. This would ensure a more accurate sizing of potential turbine and generator equipment.

5.3.2 Scoring and Ranking of Hydroelectric Projects

For each of the five hydroelectric project sites that underwent a detailed, on-site assessment, scoring was completed based on siting characteristics, generation potential, ease of interconnection with load and/or the grid, permitting and zoning, and consideration of additional sustainability criteria. The scores of each hydroelectric site were tabulated and sites ranked relative to the other projects sites. The Mountain Dell Dam site scored the highest primarily due to its generation potential, proximity to existing load, and interconnection access. A summary of the scoring and ranking results is provided in Table 5-7.

Table 5-7. Hydroelectric Project Scoring and Ranking

Project Site Name	Technology	Capacity (kW)	Score
Mountain Dell Dam	Conventional Hydroelectric	260	80.3
B11-R13	Reverse Pump Turbine	190	58.3
D74-DV1	Reverse Pump Turbine	300	55.4
B35-R18	Reverse Pump Turbine	220	53.8
C41-R20	Reverse Pump Turbine	170	53.8

5.4 Wastewater Heat Recovery

Based on the results of the Phase I preliminary evaluation, the West Temple wastewater heat recovery site located adjacent to DPU Campus was determined to be technically feasible and selected for further evaluation in Phase II.

5.4.1 Detailed Site Evaluation

Data collection consisted of a site evaluation of physical site characteristics (site usage, available space), consideration of potential usage strategies, and anecdotal information obtained from speaking with DPU employees. Relevant historical sewer flow and temperature data were also provided by DPU. The historical data was utilized to understand the energy potential associated with the site.

The proposed wastewater heat recovery facility project would utilize a heat exchanger to extract heat from wastewater flowing in the sewer trunkline along West Temple, adjacent to DPU's administration campus. The main office currently utilizes four forced air gas units to heat the facility. Wastewater heat recovery technology would utilize a portion of the flow from the adjacent sewer

line, recover heat from the water, and then return it to the sewer line. Where the flow line of the sewer line is approximately 15-feet below street level, water would be screened and pumped to a heat exchanger where heat would be transferred to a water/glycol mixture. The water/glycol mixture would then run to a heat pump which would be connected to the existing forced air system. The heat pump would utilize electric energy to boost the heat potential to the range typically required for a forced air heating system.

The peak output from the system would be approximately 737 MBH (737,000 BTU/hour) utilizing a 156-kW heat exchanger with a 60-kW heat pump. Based on the annual heating profile provided by DPU, it appears a wastewater heat recovery system would meet all the heating requirements for DPU's main office from March through October, and meet a percentage of the need during peak winter heating (January—50 percent, February—60 percent, November—70 percent, December—50 percent). The utility service that would be avoided is natural gas, while additional electricity service is required to operate the heat pump.

5.4.2 Scoring of Wastewater Heat Recovery Site

Scoring for this project considered the viability of the site to support wastewater heat recovery technology, potential to offset natural gas, interconnection with existing heating system load, permitting and zoning, and consideration of additional sustainability criteria. The West Temple Project was not scored because it is a demonstration project that will provide an opportunity to demonstrate the viability of this technology, learn about how it could be used throughout Salt Lake City, and serve as an important educational resource.

5.5 SLCWRF Biogas Cogeneration

The Salt Lake City Water Reclamation Facility was selected to be evaluated in Phase II based on the fact that the site already had a cogeneration system using a renewable energy source—biogas—to generate electricity.

Carollo Engineers prepared a technical memorandum which provides details of the site evaluation, analysis of alternative technologies, and generation assessment. The technical memorandum is included as Appendix B.

5.5.1 Detailed Site Evaluation

Currently at the SLCWRF, digester gas is collected and used to fuel a boiler for digester heating needs or cleaned prior to combustion in two 700-kW engine generators to generate electricity to serve on-site load. Electricity generated through the combustion of digester gas offsets a portion of the power that must be purchased from the local energy utility. Any digester gas in excess of what can be used in the engine generators or boiler is destroyed by flare.

The Consultant Team evaluated two options for maximizing the generation of electricity from biogas at SLCWRF: using the existing generators to combust more biogas through operational

changes, or replacing the generators with newer equipment or other technologies. Based on an analysis of current gas productions, as well as digester gas production projections, the following alternatives were developed and evaluated.

- Alternative 1—Use existing cogeneration engines, run one engine with no natural gas supplementation.
- Alternative 2—Use existing cogeneration engines, run two engines with no natural gas supplementation.
- Alternative 3—Use existing cogeneration engines, run two engines with natural gas supplementation.
- Alternative 4—Replace existing engines with a new engine.
- Alternative 5—Replace existing engines with new micro-turbine.
- Alternative 6—Replace existing engines with new fuel cell.

Each of the alternatives was evaluated based on digester gas production from two treatment process configurations, the current wastewater treatment process, and a biological nutrient removal (BNR) process, which may be required by federal water quality standards in the future.

The results of the detailed analysis as well as recommendations are provided in the complete technical memorandum in Appendix B.

5.5.2 Scoring of SLCWRF Cogeneration Site

Scoring the site was based on the of viability of the site to support generation of renewable electricity, potential to offset natural gas consumed, interconnection requirements, permitting and zoning, and consideration of additional sustainability criteria. The project site scored high due to the existence of the biogas-cogeneration system already in operation including the supporting infrastructure. On a 100 point scale, the project's score was 92.9.

5.6 Summary of Phase II Detailed Site Evaluation Scoring and Ranking

Nineteen project sites went through the Phase II detailed site assessment and were scored according to six categories using 20 criteria covering site, generation potential, interconnection and permitting requirements, zoning standards, and sustainability characteristics. Each criterion was assigned a score of 0 to 5. Scores were then tabulated and input into a spreadsheet tool that calculated a weighted average score based on 100-point scale. The higher the score the more likely the Consultant Team considered the project to be successful in meeting DPU's energy and environmental objectives. Table 5-8 includes all 19 projects ranked from highest to lowest based on the score each project site received. Appendix C provides the detailed Phase II scoring and ranking matrix input and results.

Table 5-8. Detailed Site Evaluation Scoring and Ranking

Site Name	Technology	Capacity (kW)	Scores
SLCWRF	Biogas Cogeneration	1,400	92.9
Sorenson Fitness Center	Building Solar PV	-	85.6
DPU Campus	Building Solar PV	-	85.4
15th East Reservoir	Roof-mounted Solar PV	274	84.6
South Lift Station	Ground-mounted Solar PV	289	83.3
West Temple Trunk-line	Wastewater Heat Recovery	NA	NA
Mountain Dell Dam	Hydroelectric	260	80.3
Wilson Reservoir	Roof-mounted Solar PV	255	71.9
6200 South Well	Ground-mounted Solar PV	48	68.6
Greenfield Village Well	Ground-mounted Solar PV	-	67.3
Morris Reservoir	Roof-mounted Solar PV	274	67.2
Victory Road Reservoir	Roof-mounted Solar PV	446	66.3
Terminal & Park Reservoirs	Roof-mounted Solar PV	3,488	65.0
Baskin Reservoir	Roof-mounted Solar PV	420	62.6
PRV Station B11-R13	Hydroelectric	190	58.3
PRV Station D74-DV1	Hydroelectric	300	55.4
PRV Station B35-R18	Hydroelectric	220	53.8
PRV Station C41-R20	Hydroelectric	170	53.8
Concord Lift Station	Ground-mounted Solar PV	63	50.6

The Consultant Team met with the DPU Steering Committee and used the ranked scores and information from the detailed site evaluations as the basis for developing a short list of projects that would undergo additional economic analysis and regulatory assessment. The Steering Committee and Consultant Team then selected a representative cross section of six projects from the 19 ranked projects. These six projects were advanced to a more comprehensive evaluation. The projects selected for additional assessment are listed in Table 5-9.

Table 5-9. Renewable Energy Projects Selected for Economic and Regulatory Analysis

Site Name	Technology	Capacity (kW)	Scores
SLCWRF	Biogas Cogeneration	1,400	92.9
15th East Reservoir	Roof-mounted Solar PV	274	84.6
West Temple Trunkline	Wastewater Heat Recovery	NA	NA
Mountain Dell Dam	Hydroelectric	260	80.3
Terminal & Park Reservoirs	Roof-mounted Solar PV	3,488	65.0
PRV Station B11-R13	Reverse-pump turbine	190	58.3

6.0 REGULATORY ASSESSMENT—RATE SCHEDULE ANALYSIS

The regulatory assessment addressed tariff options for each of the six renewable energy project sites. The purpose was to identify and make recommendations for the most appropriate rate schedule for the site to maximize the economic benefit of the renewable energy project. Four categories and six rate tariffs were evaluated by the Consultant Team; partial requirements tariffs designed to provide supplementary, backup, and maintenance power to customers who obtain any part of their regular electric requirements from self-generation; tariffs provided by RMP as required by the Public Utilities Regulatory Policy Act (PURPA) to promote greater use of domestic energy and renewable energy;[6] a new tariff designed to serve large customers who would like to build renewable energy projects or purchase renewable energy from third parties and deliver the power to their facilities through RMP's distribution system; and net metering tariffs that allow customers with on-site renewable energy facilities to connect to the electrical grid and receive credit for excess electricity that is produced, but not consumed, on-site. Table 6-1 provides a description of the Rate Tariffs Evaluated.

Table 6-1. Rate Tariffs Evaluated

Tariff Schedule	Description
Electric Service Schedule 31	This schedule is for customers who have on-site generation capacity and require backup and maintenance power. Schedule 31 anticipates that customers will be reducing or eliminating usage of utility power the majority of the time and does not provide credits for electricity production in excess of usage, nor does it allow for resale of excess electricity.
Electric Service Schedule 37	Schedule 37 is available to owners of certified small Qualifying Facilities (QFs): either cogeneration facilities with a design capacity of 1-MW or less, or small power production facilities with capacity of 3-MW or less. Prices for the sale of power through this schedule are published, "standard offer" rates. QFs enter into a written power sales contract with RMP based on the published prices.
Electric Service Schedule 38	Schedule 38 is available to owners of certified cogeneration QFs with capacity greater than 1-MW or small power production QFs with capacity greater than 3-MW. Large QFs negotiate pricing and contract terms directly with RMP.
Electric Service Schedule 32	Customers who want to develop their own renewable energy facilities may contract for the delivery of the electricity from their own off-site renewable projects to their facilities through this tariff. Under this tariff the customer must contract for more than 2-MW of electricity delivery and is responsible for paying all interconnection and integration costs to RMP.
Electric Service Schedule 135 – Net Metering	Schedule 135 is intended primarily to allow an on-site renewable energy project to offset part or all of the customer's own electrical requirements. The customer-generator can aggregate its electrical requirements from multiple meters for the purpose of net metering, as long as all meters are located at or adjacent to the same property. Non-residential facilities can be up to 2-MW.

[6] An owner or operator of a generating facility with a maximum net power production capacity of greater than 1-MW (1,000 kW) may obtain QF status by submitting a "self-certification" (no fee), or by applying for and obtaining FERC certification of QF status (fee required).

6.1 Salt Lake Water Reclamation Facility

The SLCWRF was recently switched from Schedule 9 to Schedule 31, which is Partial Requirements General Service for large customers with more than 1-MW of on-site generation. However, if on-site generation were less than 1-MW, the plant would return to Schedule 9 (General Service, High Voltage).[7] Schedule 31 customers are not eligible for net metering.[8]

The purpose underlying the new “Partial Requirements Service” rate schedule is to set rates such that a customer would pay an equivalent amount under Schedule 31 as they would pay under their general service rate schedule (i.e., Schedule 9) if they did not have on-site generation offsetting their bills. Since DPU has the opportunity to alter the cogeneration process at the reclamation facility, DPU should consider the economics of generation alternatives under Schedule 31 compared to Schedule 9. If on-site cogeneration capacity is less than 1-MW, the facility may revert to Schedule 9 and take backup, supplementary, and maintenance power at Schedule 9 rates.

Finally, DPU could increase use of the existing engines and produce more electricity without upgrading equipment by switching to a rate schedule that allows occasional excess generation. DPU should consider the economics of various technologies according to the rate schedules associated with on-site generation capacity greater than or less than 1-MW (under Schedules 31 and 9, respectively). Neither Schedule 31 nor Schedule 9 allows net metering. However, as a facility taking service under Schedule 31, the SLCWRF may sell excess electricity back to the utility at wholesale “avoided costs” rates using either Schedule 37 (if the capacity sold is less than 1-MW) or Schedule 38 (if greater than 1-MW).

6.2 15th East Reservoir

The 15th East Reservoir is currently receiving electricity through Schedule 6A, a “time of use” schedule that rewards facilities that shift the bulk of their electricity usage to off-peak hours with lower electricity rates during those hours. A substantial portion of the electricity usage at the reservoir appears to be during on-peak hours where Salt Lake City is paying the highest rate. Schedule 6A might not currently be providing the most advantageous rates for this facility. A solar installation will provide electricity primarily during on-peak hours, reducing usage at the reservoir during that time, so Schedule 6A will be a more practical rate schedule for this facility if solar PV is installed.

If a solar PV array is designed to meet existing load and installed at the 15th East Reservoir, the site would be a good candidate for RMP’s Schedule 135 Net Metering Tariff. However, net metering does not allow a customer to receive credits in excess of their annual usage, so in order to make the solar project a good candidate for net metering, the size of the system needs to be designed based on the average annual electricity usage at this site (rather than the area available for a solar installation at

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[7] The applicability of Schedule 31 recently changed from an elective rate schedule for customers with specific attributes, to a mandatory rate schedule for customers with more than 1-MW of on-site generation.

[8] Schedule 135 is available to non-residential Schedules 6, 6A, 6B, 8, 10, 15, and 23, which all take service at distribution voltage.

the site). It would be possible to install a larger solar array at the site, however electricity generation from the solar PV would exceed the on-site electricity load, and DPU could not receive net metering credits for electricity generated in excess of the annual usage.

Given that the technical potential for solar generation at this site greatly exceeds on-site electricity usage, DPU could choose to construct a larger solar installation than is necessary to meet electricity needs on-site and instead contract to sell the excess electricity in one of two ways. First, this site could be developed to deliver electricity directly to DPU as one project in a portfolio of DPU-owned renewable projects through the contracting provisions allowed under Electric Service Schedule 32. This tariff was enabled by Senate Bill 12 (SB 12) in 2012 (codified at Utah Code Ann. Section 54-17-801, et seq.). Although customers utilizing Schedule 32 must contract to take more than 2-MW of electricity, the law permits multiple renewable energy facilities with 2-MW of aggregated capacity to deliver electricity to a single contract customer. While the cogeneration facility is technically eligible for Schedule 32, this rate schedule will likely only be advantageous for waste heat projects due to the method by which the charge for demand is calculated.

A solar installation at the 15th East Reservoir could certify as a QF and contract to sell electricity to RMP under Electric Service Schedule 37's "avoided cost" rates. Pricing under Schedule 37 was recently litigated and the newly approved published rates are available up to 25-MW of project capacity until next year, when RMP must update pricing again.

6.3 Mountain Dell Reservoir

The Parley's Canyon Water Treatment Plant is currently receiving electricity through Schedule 6A, a "time of use" schedule that rewards facilities that shift the bulk of their electricity usage to off-peak hours with lower electricity rates during those hours. Electricity usage at Parley's Water Treatment Plant appears to be fairly evenly split between on-peak hours and off-peak hours, and so rate Schedule 6A might not currently be providing the most advantageous rates for this facility if a renewable energy project is not developed on-site.

If the hydroelectric project is developed this site is a good candidate for net metering on Schedule 135. A 260-kW hydroelectric turbine falls under the 2-MW capacity limit allowed through Schedule 135. The hydroelectric turbine would produce more electricity in the summer months: an average of 442 MWh annually during the summer season and 247 MWh annually during the winter season. This seasonality is advantageous for a net-metered facility. Credits for excess generation roll over from month to month and can be used to offset future electricity bills, however, all credits for excess generation are forfeited at the end of the annualized billing period, on March 31st.

6.4 Terminal and Park Reservoirs

There is minimal on-site load at this facility compared to the technical potential of the site, so net metering is not a practical option for this site. A solar facility built to take advantage of the available space could produce a substantial amount of electricity. There are four options available for a solar

facility at the Terminal and Park Reservoirs, two of which are immediately available. A third option, Schedule 32, will be available as soon as the proposed tariff is finalized by the Public Service Commission.

Electric Service Schedule 32 is designed to serve large customers, like DPU, who would like to source a larger portion of their electric service from renewable energy resources than is currently available through RMP. Using Schedule 32, large customers will be able to build or purchase energy from off-site renewable energy projects and pay RMP for the delivery of such electricity to their facilities. Thus, DPU could build a solar facility at Terminal and Park Reservoirs and contract for the delivery of electricity from the Reservoirs to another facility through this tariff. Although solar facilities are technically eligible for Schedule 32, this rate schedule may not be advantageous for solar projects due to the method by which the charge for demand is calculated.

Using Schedule 37, DPU could certify the Terminal and Park Reservoirs as a QF and contract to sell electricity to RMP using "avoided cost" rates available to renewable QFs sized 3-MW and smaller.[9] Since Schedule 37 is only available to small projects (3-MW and under), DPU has a couple of options for this site:

- Certify this facility as a QF, build a 3-MW project, and sell the electricity to the utility under Schedule 37.
- Have two separate project owners develop QF projects, each smaller than 3-MW, in order to take advantage of the full technical potential at the site. A single QF project owner may not build more than one project (of the same technology) within a single mile radius; however, Salt Lake City could work with the Metropolitan Water District of Salt Lake and Sandy (MWDSLS) (the owner of two of the water tanks comprising the facility) to develop two separate QF projects at the Terminal and Park Reservoirs, owned by Salt Lake City and MWDSLS respectively. Both facilities could use the same interconnection point, and it may be possible to operate both QFs as a single facility.

Pricing under Schedule 37 was recently litigated and the newly approved published rates are available to 25-MW of project capacity until next year, when RMP must update pricing again. This option is available now and current prices are provided in Table 6-2.

Table 6-2. Schedule 37 Levelized Prices (Nominal) for Solar PV (Cents per kWh)

	On-Peak Energy Prices		Off-Peak Energy Prices	
	Winter	Summer	Winter	Summer
Fixed Tilt Solar PV	4.013	4.246	3.548	3.781
Tracking Solar PV	4.188	4.420	3.613	3.846

9 For more information about QFs, how to become certified as a QF, and Schedule 37 See Appendix D, "Schedule 37."

Through Schedule 38, the Terminal and Park Reservoirs could certify as a QF and contract to sell electricity to RMP using "avoided cost" rates, available to renewable QFs larger than 3-MW.[10] Unlike Schedule 37, pricing under this schedule is not published; rather, the Commission approved a pricing calculation method that RMP uses to establish "indicative prices" upon request. Pricing and contract terms are then negotiated directly with RMP. Because negotiating pricing with RMP can be a costly and time consuming process, this option, though available to facilities as small as 3-MW, may not be economically feasible for a project smaller than 20-MW. This tariff will be undergoing pricing and process revisions in the coming months.

6.5 PRV Station B11-R13

A 190-kW hydroelectric turbine is proposed to generate electricity using pressure head at an existing PRV in a vault structure. There is no on-site load at this location, so there are a few potential options for using the energy produced at this facility, of which only one is immediately available.

A hydroelectric turbine at this site could certify as a QF and contract to sell electricity to RMP under Electric Service Schedule 37 "avoided cost" rates, available to renewable QFs 3-MW and smaller.[11] Pricing under Schedule 37 was recently litigated and the newly approved published rates are available up to 25-MW of project capacity until next year when RMP must update pricing again. This option is available now and current prices are provided in Table 6-3.

Table 6-3. Schedule 37 Levelized Prices (Nominal) for Baseload Renewable Energy (Cents per kWh)

	On-Peak Energy Prices		Off-Peak Energy Prices	
	Winter	Summer	Winter	Summer
Baseload Renewable Energy	4.589	4.819	3.859	4.089

This site could potentially sell electricity through the contracting provisions enabled under Electric Service Schedule 32. Although customers utilizing Schedule 32 must contract to take more than 2-MW of electricity delivery through Schedule 32, the law permits multiple renewable energy facilities to deliver electricity to a single contract customer. Thus, this site could be one of a portfolio of facilities serving DPU load under Schedule 32.

10 For more information about QFs, how to become certified as a QF, and Schedule 38 See Appendix D, "Schedule 38."

11 For more information about QFs, how to become certified as a QF, and Schedule 37 See Appendix D, "Schedule 37."

7.0 ECONOMIC ANALYSIS OF RENEWABLE ENERGY PROJECTS

The DPU Steering Committee and the Consultant Team identified project opportunities at six sites for further economic and regulatory assessment. This section describes the approach, assumptions and results of the economic analysis for each project.

The economic analysis is performed using an annual cash flow model developed by Energy Strategies. The model looks at the economic viability of each project by quantifying the net present value (NPV) of the cost of utility service. The cost of utility service measures the cash flow throughout the life of the project, compared to a business-as-usual (BAU) case where DPU continues to receive utility service from either RMP or Questar. If the NPV is negative then the project is economical, i.e., the costs producing electricity or savings of natural gas due to the renewable energy project is less than utility service over the life of the project.

The model also estimates the levelized cost of power and avoided GHG emissions for each project compared to utility service from RMP and Questar. The economic model also accounts for increases and decreases in the following measures versus the relevant business as usual scenario:

- On-site generating capacity, kW
- Overnight capital, 2014$ millions
- Average annual generation, MWh
- Non-fuel operating expense, 2014$ millions
- As modeled assuming $0 per $MTCO_2e$ compliance cost
- Sensitivity analysis at $25 and $50 per $MTCO_2e$ compliance cost

A single power generation technology was evaluated for each of four sites proposed for renewable energy development: 15th East Reservoir, B11-R13, Mountain Dell Dam, and Terminal and Park Reservoirs. Four new power generation technologies were evaluated for the fifth site, the SLCWRF. An economic analysis was also conducted for the 1530 South West Temple wastewater heat recovery project but it was based on natural gas saved.

The dollar value assigned to generation is a key assumption. For all but two options, it is assumed that generation would offset purchases of power from RMP and the value of the generation is based on current prices in the electric service schedule that applies to each site.

In the cases of the PRV station B11-R13 and Terminal and Park Reservoirs, generated power exceeds site requirements and is assumed to be sold back to RMP under the Schedule 37 rate. In addition, a sensitivity analysis was conducted on these two sites to evaluate the economic feasibility of those projects if DPU were able to receive credit for excess generation and use it to offset DPU electricity bills at other locations.

7.1 SLCWRF Biogas Cogeneration Site

The SLCWRF biogas cogeneration site is located at Redwood Road and approximately 2000 North in Salt Lake City. Cogeneration already exists at the SLCWRF, where biogas is burned to run two 700-kW engines. The Phase II detailed site evaluation found that the cogeneration system is operating at 48 percent of its nameplate capacity, and generates an average of 5,230 MWh per year to meet the SLCWRF's annual load of 10,858 MWh. In practice, the SLCWRF is running a single engine and consuming 68 percent of the 97,637 MMBtu of biogas produced at the treatment plant each year. The remaining biogas is either consumed as boiler fuel or flared. Five cogeneration options were evaluated for the SLCWRF. Cogeneration capacity estimates varied from 666-kW to 1400-kW for the alternatives evaluated.

Two of the alternatives used operational changes to maximize the use of the two existing 700-kW reciprocating engines. The first alternative evaluated running the engines at a capacity factor high enough to utilize all the biogas produced at the treatment plant. The second alternative assumed the engines were run at their maximum operating capacity which would require the biogas be supplemented with natural gas. The other three options evaluated included replacing the existing engines with a new 1,426-kW reciprocating engine, a 1,000-kW micro-turbine, or 1,400-kW fuel cells. Each of the five power generation technologies considered were also evaluated under two wastewater treatment process scenarios: 1) current process (primary clarification, trickling filters, aeration basins, secondary clarifiers, and solids digestion); and 2) biological nutrient removal process.

To the extent cogeneration at the SLCWRF is currently being limited to one engine, there appears to be an economic opportunity to lower the cost of electricity service supplied to the plant by operating both existing engines using biogas and natural gas as fuels.

If the two existing 700-kW engines are run utilizing only the biogas produced by the treatment plant, DPU would reduce NPV of utility service by $1.458 million over the 20-year life of the project, compared to continuing to receive the same level of service from RMP. If a cost of carbon of \$25/MTCO$_2$e or \$50/MTCO$_2$e is assumed in the cash flow analysis, then NPV of the economic benefits of the project increase to $2.0 million and $2.5 million respectively.

Running both engines at the capacity factor they are designed to operate at would require utilizing all of the biogas produced at the plant and additional purchase of supplemental natural gas service from Questar. Still, even under this scenario, operating the cogeneration engines to supply electricity to the site proved to be more economical compared to purchasing the equivalent amount of power from RMP. Doing so would reduce NPV of electricity service to the SLCWRF by $243,000 over the 20-year life of the project. If a cost of carbon of \$25/MTCO$_2$e or \$50/MTCO$_2$e is assumed in RMP's electricity rates, then NPV of the economic benefits of the project increases to $697,000 and $1.12 million respectively.

Table 7-1. Technologies Evaluated For Salt Lake City Water Reclamation Facility

Project Site	Type of Power Technology	Effective Generation Capacity kW	RMP Electricity Service Schedule	Total Fuel Consumed MMBTU	Digester Gas Available MMBTU	Natural Gas Consumed	Average Annual Generation MWh
Salt Lake City Water Reclamation Facility	Existing Recip (Run 1)	1,320	RMP 31 (9)	66,151	97,637	-	
	Existing Recip (Run 2 no NG)	1,320		97,128		-	2,553
	Existing Recip (Run 2 with NG)	1,320		111,818		14,181	3,642
	New Recip	1,390		88,333		-	3,855
	Microturbine	844		77,457		-	1,124
	Fuel Cell	1,330		94,582		599	5,187
Salt Lake City Water Reclamation Facility Biological Nutrient Removal	Existing Recip (Run 1)	1,320	RMP 31 (9)	61,651	59,672	1,979	
	Existing Recip (Run 2 with NG)	1,320		111,818		52,146	4,130
	New Recip	827		58,111		289	671
	Microturbine	562		60,816		1,562	-506
	Fuel Cell	855		71,555		11,883	1,964

Moreover, both approaches would result in a meaningful reduction of GHG emissions compared to the current operations where one engine is operated. In the case where both engines are operated based on the available biogas supply from the plant, GHG emissions will be reduced by 1,558 tons, or about 6 percent of DPU's estimated CO_2 emissions emitted from the consumption of electricity and natural gas. Burning all available biogas plus supplemental natural gas to maximize output of the cogeneration engines will also reduce net GHG emissions compared to the reference case by 1,223 tons.

Replacing the existing engines with new reciprocating engines, micro-turbines, and fuel cells was also evaluated. All scenarios where the existing engines were replaced with new cogeneration technology entail significant incremental investment of capital (between $5 and $12 million), making replacement of the existing engines uneconomical. Even when a value of $50 per $MTCO_2e$ is attributed to GHG emissions, replacing the existing engines with newer generation technology is not justified if lowering the cost of electricity service at the SLCWRF is the objective.

The economic analysis described above assumed that SLCWRF would continue to treat effluent using the current process (primary clarification, trickling filters, aeration basins, secondary clarifiers, and solids digestion). If the SLCWRF is required to implement a biological nutrient removal process, this will significantly lower the amount of biogas produced and negatively impact the economic value of all cogeneration opportunities at the SLCWRF. However, the SLCWRF can continue to

operate the existing biogas cogeneration engines, and maximize their use through operational changes, until required to switch to a biological nutrient removal process.

Table 7-2. Salt Lake City Water Reclamation Facility NPV of the Cost of Utility Service

Project Site	Type of Power Technology	Overnight Capital	Non-Fuel Operating Expense	Cost of Utility Service Present Value $Millions			Levelized Cost
		2014$ Millions	2014$ Millions	$0 per MTCO2e	$25 per MTCO2e	$50 per MTCO2e	$ per MWh
Salt Lake City Wastewater Reclamation Facility	Existing Recip (Run 2 No NG)	$0.00	$76.58	($1.46)	($1.996)	($2.533)	$26.50
	Existing Recip (Run 2 with NG)	$0.00	$109.27	($0.27)	($0.697)	($1.120)	$35.50
	New Recip	$9.36	$25.06	$5.94	$5.092	$4.240	$80.00
	Microturbine	$6.73	$65.36	$6.42	$6.169	$5.920	$95.00
	Fuel Cell	$12.09	$328.18	$12.31	$11.181	$10.046	$111.00
	Biological Nutrient Removal						
	Existing Recip (Run 2 with NG)	$0.00	$123.91	$3.11	$3.468	$3.824	$61.50
	New Recip	$8.58	($33.73)	$6.99	$6.785	$6.581	$113.50
	Microturbine	$5.30	$5.88	$5.63	$5.713	$5.795	$108.50
	Fuel Cell	$10.67	$192.50	$12.49	$12.222	$11.953	$149.50

7.2 15th East Reservoir Solar PV Site

The 15th East Reservoir Solar PV site is located at a partially buried concrete reservoir directly east of Rice Eccles Stadium along 500 South in Salt Lake City. The site scored high on the detailed site evaluation and was considered a good candidate site for a future solar PV energy project. The development site would be located on an existing concrete reservoir with open roof space that could support a 274-kW solar PV installation. The majority of the large roof space is relatively new and unobstructed by objects that would create shading impacts. The reservoir is currently surrounded by adequate security fencing, and for the most part is not visible to public at the ground level. The location also has direct access just east of the site to three-phase electrical distribution. There is also on-site access to a DPU load at the University Pump Station and 500 South Well.

A 274-kW solar installation was evaluated at the 15th East Reservoir. A system this size could produce an average of 335,000 kWh of electricity each year. However, electricity meters located at this site report that the on-site load is only 70,000 kWh of electricity each year. This site could support almost five times more solar than is necessary to meet the electricity needs of the on-site facilities. A smaller 25-kW installation at this site could net meter and offset on-site electricity usage however this option was not evaluated. The larger installation would produce more electricity than could be used on-site, and DPU would have to contract to sell the electricity in order to see a financial benefit.

The economic analysis conducted for the 15th East Reservoir site assumed the maximum number of solar panels the site could support would be installed on the roof of the reservoir. The upfront capital costs of the 274-kW solar PV system was estimated to be $920,000, and NPV of operation and maintenance at the site was estimated to be $13,000 per year. Assuming the value of the PV generation at the site would be based on the Schedule 6A rate, NPV of the power generated by the solar array is estimated to exceed the value of electricity supplied by RMP by $426,000 over the 30-year life of the project. Even when a price of carbon of $50/MTCO$_2$e is assumed in the analysis, the project still has an NPV of $200,000 more than service provided by RMP.

However, a smaller, net-metered installation designed to offset on-site electrical usage was not run through the economic analysis. It would likely have a better NPV than the 274-kW project that was evaluated. A lease or a PPA, which was not considered in this evaluation, would allow DPU to take advantage of a federal tax incentive through a third-party ownership structure and could result in a cost reduction of up to 30 percent of. If DPU were to utilize a lease or a PPA, consider optimizing the size of the project based on on-site load, and take advantage of the falling cost of solar, it is likely that this project would offer a better NPV than the cost of utility service over the life of the project.

Table 7-3. 15th East Reservoir NPV of the Cost of Utility Service[12]

Project Site	Type of Power Technology	Use of Generation	Overnight Capital	Non-Fuel Operating Expense	Cost of Utility Service Present Value $Millions			Levelized Cost
			2014$ Millions	2014$ Millions	$0 per MTCO2e	$25 per MTCO2e	$50 per MTCO2e	$ per MWh
15th East Reservoir	Solar PV	Net Metered	$0.920	$0.013	$0.426	$0.314	$0.202	$153.50

7.3 Mountain Dell Dam Hydroelectric Site

The Mountain Dell Dam Hydroelectric site is located at the Parley's Water Treatment Plant along I-80 in Parley's Canyon. A hydroelectric facility would likely be located at the downstream toe of Mountain Dell Dam just upstream of the water treatment facility. The Mountain Dell Dam site was selected by the DPU Steering Committee and Consultant Team for further economic analysis and electric rate assessment because of the following favorable project site characteristics:

1. Sufficient flow to support year-round generation of power.
2. Presence of an existing dam with a water source that employs an energy dissipation valve to burn energy just upstream of the water treatment plant.
3. Available space to develop a facility with the removal of an existing concrete structure (sand separator) and modifications to existing piping.
4. Direct access on-site to water treatment plant facility electrical load and three phase electrical distribution.

[12] Costs and NPV are for a turnkey project without using a PPA or other incentives.

5. Simplified FERC permitting process as power would be a secondary beneficial use of the water, the conduit is owned by Salt Lake City, and the generation capacity is less than 5-MW.

Based on a review of the site and previously performed hydroelectric analyses at Mountain Dell Dam, the Consultant Team concluded there is sufficient space to develop a project at the toe of the dam just upstream of the water treatment plant. The hydroelectric plant would be operated by utilizing water from the Little Dell Reservoir through a 42-inch diameter bypass line 24 hours a day, 365 days a year. The hydroelectric facility would likely utilize a Crossflow-type turbine with an installed capacity of 260-kW and an average annual generation of 690,000 kWh. On-site load at Parley's Treatment Plant is approximately 900 MWh annually, so the electricity produced by a hydroelectric turbine at this location could be used to offset roughly three quarters of electricity used at this site.

Parley's Water Treatment Plant is currently receiving electricity through Schedule 6A. The economic analysis conducted for the Mountain Dell Dam site assumed a 260-kW turbine is installed and generates an annual average 690,000 kWh that is used to offset 75 percent of the load at the Parley's Treatment Plant. Accordingly, the value of the generation from the hydroelectric project was assumed to be the average retail rate for Schedule 6A, which is $11.2772 cents per kWh.
The upfront capital costs of the turbine and power system is estimated to be $1.6 million and the annual average non-fuel operating expenses are estimated to be $19,000 per year. Assuming the value of the generation at the site is based on the Schedule 6A rate, NPV of the power generated by the hydroelectric project is estimated to exceed the value of electricity supplied by RMP by $355,000 over the 50-year life of the project. However, when a price of $50/MTCO$_2$e is assumed in the cash flow analysis, the project's NPV is $228,000 less than service provided by RMP, and this site is considered to be economically viable option for a renewable energy project.

Table 7-4. Mountain Dell Dam Hydroelectric NPV of the Cost of Utility Service

Project Site	Type of Power Technology	Use of Generation	Overnight Capital	Non-Fuel Operating Expense	Cost of Utility Service Present Value $Millions			Levelized Cost
			2014$ Millions	2014$ Millions	$0 per MTCO2e	$25 per MTCO2e	$50 per MTCO2e	$ per MWh
Mountain Dell Dam	Hydroelectric	Net Metered	$1.551	$0.019	$0.355	$0.064	($0.228)	$92.00

7.4 Terminal and Park Reservoirs Solar PV Site

The Terminal and Park Reservoirs solar PV site is located directly west of I-215 at 3300 South in Salt Lake County.

The Terminal and Park Reservoirs site consists of four buried reservoirs (Terminal South, Terminal North, Sam Park, and Sam Park West) with open roof space that could be made available for installation of ground-mounted solar PV panels. The location provides a site that is unobstructed by

objects that would create shading impacts, security fencing, and direct access just south and west to a three-phase electrical distribution system.

A solar PV facility at the Terminal and Park Reservoirs site would likely utilize fixed tilt 275-W PV modules with an installed capacity of 3.5-MW AC and an average annual generation of 4,490,000 kWh.

A 3.5-MW solar PV installation was evaluated for Terminal and Park Reservoirs. The upfront capital costs of the system were estimated to be $11.3 million, and the annual non-fuel operating expense estimated at $13,000 per year. There is virtually no on-site load at this facility compared to the technical potential of the site, so net metering is not a practical option for this site. There are four options available for distributing the excess generation from a solar facility at the Terminal and Park Reservoirs, three of which are immediately available: Tariff Schedules 32, 37, and 38.

Assuming the value of the PV generation at the site would be based on the Schedule 37, NPV of the power generated by the solar array is estimated to exceed the value of electricity supplied by RMP by $10.2 million over the 30-year life of the project. Even when a price of carbon of $50/MTCO$_2$e is assumed in analysis the project still has an NPV of $7.2 million more than service provided by RMP.

Because Schedule 32 had not been finalized by the Public Service Commission at the time of the economic analysis, the economic viability of this tariff option was not evaluated. Although solar facilities are technically eligible for Schedule 32, this rate schedule may not be advantageous for solar projects due to the method by which the demand is calculated. However, this analysis did estimate NPV of the cost of utility service if an alternative net metering tariff were available to DPU and the electricity generated from the PRV Station B11-R13 could be credited to offset DPU loads at other locations. For purposes of this analysis it was assumed the applicable tariff is Schedule 6A.

The only circumstance where the Terminal and Park Reservoirs site would provide lower cost electricity service compared to RMP is by assuming an alternative net metering tariff is available to DPU at the equivalent of the average retail rate for Schedule 6A (i.e., 11.2772 cents per kWh), and including a $50/MTCO$_2$e in the cash flow analysis. Under this scenario, NPV of utility service of this project is $559,000 less than service provided by RMP.

This analysis did not include an assessment of leases or PPAs. Either of these financing structures would allow DPU to take advantage of a 30 percent federal tax incentive through a third-party ownership. Furthermore, the cost of solar has fallen significantly since this report was commissioned. If DPU were to utilize a lease or a PPA, take advantage of the falling cost of solar, and/or apply to receive an incentive through the Utah Solar Incentive Program, this project might offer a better NPV than the existing cost of utility service.

Table 7-5. Terminal and Park Reservoirs NPV of the Cost of Utility Service

Project Site	Type of Power Technology	Use of Generation	Overnight Capital	Non-Fuel Operating Expense	Cost of Utility Service Present Value $Millions			Levelized Cost
			2014$ Millions	2014$ Millions	$0 per MTCO2e	$25 per MTCO2e	$50 per MTCO2e	$ per MWh
Terminal Park Reservoir	Solar PV	Schedule 37	$11.292	$0.150	$10.155	$8.699	$7.242	$139.50
	Solar PV	Net Metered			$2.354	$0.898	($0.559)	$139.50

7.5 PRV Station B11-R13 Hydroelectric Site

The PRV station B11-R13 hydroelectric site is located at the intersection of 1000 East 500 South in Salt Lake City. An existing vault containing two PRV valves is located on-site. A hydroelectric facility would likely be located at the same location or adjacent to the existing PRV vault.

A 190-kW hydroelectric turbine is proposed to generate electricity using pressure head at an existing PRV in a vault structure. A hydroelectric facility at the B11-R13 PRV would likely utilize a reverse pump-type turbine with an installed capacity of 190-kW and an average annual generation of 773,000 kWh.

The upfront capital costs of this renewable energy system are estimated to be $1 million and the annual non-fuel operating expense at the site is estimated to be $13,000 per year. Interior lighting for the vault is the extent of the on-site load, so net metering is not a practical option for this site. There are only two options available for distributing the generation from the B11-R13 PRV vault, Tariff Schedules 32 and 37.

Assuming the value of the electricity produced at the site would be based on the Schedule 37, NPV of the power generated by this micro-hydroelectric project is estimated to exceed the value of electricity supplied by RMP by $585,000 over the 50-year life of the project. However, when a price of $50/MTCO$_2$e is incorporated into the cash flow analysis, the project is economic. Under this scenario, NPV of the cost of utility service is $68,000 less than service provided by RMP.

Because Schedule 32 had not been finalized by the Public Service Commission at the time of the economic analysis, the economic viability of this tariff option was not evaluated. However, this analysis did estimate the NPV of the cost of utility service if an alternative net metering tariff were available to DPU. Alternative net metering tariffs could allow parties who own renewable generation facilities at one location to receive credit for that generation at another. Under such a tariff, the facility does not have to be adjacent to the renewable energy project. In this scenario, electricity generated from the B11-R13 PRV station could be credited to offset DPU loads at other locations. For purposes of this analysis it was assumed the value of electricity that would be offset by the PRV station micro-hydroelectric project would be equivalent to the published Schedule 6A rate.

Table 7-6. PRV Station B11-R13 Hydroelectric NPV of the Cost of Utility Service

Project Site	Type of Power Technology	Use of Generation	Overnight Capital	Non-Fuel Operating Expense	Cost of Utility Service Present Value $Millions			Levelized Cost
			2014$ Millions	2014$ Millions	$0 per MTCO2e	$25 per MTCO2e	$50 per MTCO2e	$ per MWh
PRV Station B11-R13	Micro-Hydro	Schedule 37	$0.999	$0.015	$0.585	$0.258	($0.068)	$55.50
		Virtual Net Metering			($0.188)	($0.515)	($0.841)	$55.50

Assuming an alternative net metering tariff is available improves the economic viability of the B11-R13 PRV project significantly. NPV of electricity service from the project is $188,000 less than electricity service provided by RMP over the 50-year project life. When a cost of CO_2e is incorporated into the cash flow analysis, the economics of the project are strengthened even further. At $25/MTCO_2e$, NPV is $515,000 less than the business-as-usual scenario; and when the price of carbon is assumed to be $50/MTCO_2e$, NPV of the project improves to $841,000.

7.6 West Temple Wastewater Heat Recovery Site

The wastewater heat recovery site, located adjacent to DPU's main office in Salt Lake City, would utilize a heat exchanger to extract heat from wastewater flowing in the sewer trunkline along West Temple. A heat exchanger and pump would be utilized to provide space heating to DPU's main office.

The economic analysis at this site was performed assuming the addition of a 156-kW heat exchanger with a 60-kW heat pump tied into the 36-inch sewer trunkline adjacent to the main DPU office building, and that the addition of a new, low-heat delivery system would be integrated with the existing buildings. The upfront capital costs of the wastewater heat recovery system and low temperature heat delivery system was estimated to be $695,000, and the annual non-fuel operating expenses were assumed to be zero. The system is estimated to conserve 1,862 MMBtu of natural gas annually. However, the addition of a heat pump would increase electricity use at DPU's main office by 123.6 MWh each year. Based on these assumptions, NPV of the cost of utility service of the wastewater heat recovery system is estimated to exceed the value of natural gas service provided by Questar by $602,000 over the 30 year-life of the project. At a price of $50/MTCO_2e$, the project only performs marginally better due to the fact the annual average avoided carbon dioxide emissions from the project is only 41 metric tons per year.

Table 7-7. West Temple Wastewater Heat Recovery NPV of the Cost of Utility Service

Project Site	Type of Power Technology	Use of Generation	Overnight Capital	Non-Fuel Operating Expense	Cost of Utility Service Present Value $Millions			Levelized Cost
			2014$ Millions	2014$ Millions	$0 per MTCO2e	$25 per MTCO2e	$50 per MTCO2e	$ per MWh
DPU Office	Heat Recovery	N/A	$0.695	$0.000	$0.602	$0.584	$0.566	N/A

8.0 POTENTIAL PROJECT FINANCING MECHANISMS

This section of the plan is intended to assist DPU with identifying financing mechanisms to support the deployment of renewable energy technologies on DPU-owned and operated property. While the Consultant Team recognizes it is DPU's preference to internally fund renewable energy projects using revenue from its utility operations, there are opportunities to leverage DPU's available funds with other funding sources to accelerate the deployment of City-owned renewable energy projects and the benefits associated with renewable energy deployment. This includes creating new local-based economic opportunities, increasing diversity of DPU electricity supply, mitigating risk of higher energy prices in the future, and reducing CO_2 emissions.

8.1 Apply for the Utah Solar Incentive Program (USIP)

This program is available to any customer whose bills are subject to the Schedule 195 solar incentive program surcharge. In 2016, the program will provide a $0.85 per-watt incentive for the upfront cost of installing a solar project less than 25-kW in size, or a $0.65 per-watt incentive for a solar project greater than 25-kW in size (with a maximum value of $650,000). The incentive is awarded through a lottery. In 2016, incentives will be available for 4,500-kW of capacity for projects less than 25-kW in size, and 10,000-kW of capacity for projects greater than 25-kW in size. In 2014, RMP awarded incentives to 100 percent of small commercial applicants and 37 percent of large commercial applicants. The USIP cannot be used in conjunction with any other RMP grant or incentive programs, including the Blue Sky Community Grants. For more information and application instructions, see Appendix D.

8.2 Apply for a Blue Sky Community Grant

Renewable energy installations, including hydroelectric projects, can apply to receive a Blue Sky Community Grant. RMP accepts applications for Blue Sky Community grants on an annual basis. Blue Sky grants can only fund up to 60 percent of the total project costs. See Appendix D for more details.

8.3 Consider a PPA

Power Purchase Agreements (PPAs) are available to local governments in Utah for net-metered projects. PPAs are a commonly used financing mechanism for solar installations, offering solar electricity at no upfront cost. PPAs allow a third-party developer to build, own, and maintain a solar photovoltaic system at a DPU facility. DPU would agree to purchase electricity produced by the solar panels at a fixed price for a predetermined time period. This arrangement offers significant cost savings because the third party developer can take advantage of tax credits and pass on the savings to DPU. A PPA can include a "buy-out" option which would allow DPU to purchase the solar facility at a pro-rated price after the tax benefits have been utilized by the developer or investor. See Appendix D for more details.

8.4 Utilize Qualified Energy Conservation Bonds

Qualified Energy Conservation Bonds (QECBs) are a debt instrument that enables qualified states, territories, and local governments to issue tax credit bonds with very low effective interest rates in order to fund energy conservation or renewable energy projects. The State of Utah, Salt Lake City, and Salt Lake County all received a separate allocation for QECBs from the U.S. Department of the Treasury, and the majority of these allocations are still available. For more information about QECBs and how to apply, see Appendix D.

8.5 Finance with the U-Save Energy Fund Program

The U-Save Energy Fund finances energy-related cost reduction retrofits on existing equipment and installations for publically owned buildings by offering loans with low interest rates. A revolving loan mechanism allows borrowers to repay the loans using cost savings realized from the retrofits. Entities considering use of the U-Save Energy Fund are encouraged to evaluate renewable energy technologies, including rooftop solar water and space heating installations, solar photovoltaic, and small wind installations. A revolving loan mechanism allows borrowers to repay the loans using cost savings realized from the retrofits. For more information about the U-Save Energy Fund and instructions for applications, see Appendix D.

9.0 SUMMARY AND CONCLUSIONS

This Plan is a broad framework that identifies DPU's opportunities for renewable energy projects; evaluates their technical, economic, and practical feasibility; and provides strategies and recommendations for their implementation.

The purpose of the plan is to provide DPU with sufficient detail on the final selected 19 renewable energy projects that were evaluated in the Phase II detailed site evaluation to either allow for the subsequent development of renewable energy projects or to identify sites that show potential and are good candidates for additional assessment.

One of the objectives of this analysis was to identify potentially viable renewable energy projects that could increase the diversity of DPU's electricity supply and contribute to growing Salt Lake City's renewable energy portfolio and reducing its GHG footprint. It is clear from this assessment that DPU-managed infrastructure and property can support a diverse portfolio of renewable energy technologies and projects. Among the technologies evaluated at the 19 Phase II selected sites were biogas-fired cogeneration, distributed roof-mounted solar PV, utility-scale roof- and ground-mounted solar PV systems, conventional hydroelectric generation, wastewater heat recovery, and micro-hydroelectric projects. When combined, these sites demonstrate the technical potential to support the installation of renewable energy capacity that would generate 13,690 megawatt-hours (MWh) of electricity, enough to offset approximately 44 percent of the electricity currently purchased from Rocky Mountain Power and Murray City. The renewable energy potential is even greater if all 41 sites that were evaluated in Phase I are accounted for. Including these additional sites raises the renewable energy generation potential to 18,779 MWh.

Of course these numbers only represent the technical potential. Economics and regulatory feasibility are also necessary considerations that need to be accounted for when a decision is made to implement a project. From the outset it was understood that this study would form the foundation and provide guidance for more detailed future evaluations of project sites that could include analysis using more detailed engineering, site, and economic assessments. The scope of work and budget for this study did not allow for a regulatory assessment of rate schedules and economic analysis to be completed for each of the 19 candidate project sites that showed high technical potential. Accordingly, the DPU Steering Committee and Consultant Team selected six representative sites for further analysis that would enable DPU to benchmark the regulatory and economic performance of the remaining 13 sites and technologies for future consideration.

9.1 Economic Analysis

Of the six renewable energy project sites selected for the more detailed regulatory and economic assessment, five sites involved projects that would generate electricity; the Terminal and Park Reservoirs, 15th East Reservoir, Mountain Dell Dam, PRV Station B11-R13, and the Salt Lake City

Water Reclamation Facility biogas cogeneration project. One site, the DPU Campus wastewater heat recovery project, would offset heating load, decreasing the purchases of natural gas.

The combined estimated overnight capital investment required to develop the four solar PV projects and hydroelectric projects is $14.8 million. Based on the generation capacities assumed in this analysis these four projects would be able to generate 6,287 MWh of electricity and avoid 4,735 $MTCO_2e$ of GHG emissions.

The economic analysis of biogas cogeneration at the SLCWRF considered increasing the generation of underutilized capacity of the two engines and replacement with four different technology options utilizing biogas produced at the treatment plant. If the SLCWRF retained the use of the two 700-kW reciprocating engines and operated them to utilize all the available biogas produced at the treat plant, it could avoid any additional capital investment and generate 2,553 MWh more electricity while reducing the GHG emissions associated with SLCWRF operations by 1,558 $MTCO_2e$. An overnight capital investment of between $6.7 and $12.1 million would be required to replace the two existing 700-kW engines with either a new 1400-kW reciprocating engine, an 844-kW micro-turbine or a 1330-kW fuel cell.

For an estimated capital investment of $695,000, DPU could also install wastewater heat recovery technology to supplement heating load at DPU's main office complex. This option would reduce natural gas consumed by the existing boiler by 1,862 MMBTU but increase the electricity consumption by 123.6 MWh, resulting in a net reduction of GHG emissions of 41 $MTCO_2e$.
For purpose of this study, the economic viability of each project is determined by quantifying the NPV of the cost of utility service, as measured by cash flow throughout the life of the project, and then comparing the costs to a business-as-usual case where DPU continues to receive utility service from either RMP or Questar. If NPV is negative, the costs of electricity or natural gas produced by the renewable energy project is less than utility service over the life of the project. Therefore, the project is economical.

While all six projects were technically feasible and provided good locations for the development of renewable energy, only one project proved to be economically viable under the current regulatory, utility pricing, and economic assumptions adopted for this analysis. Using the NPV of the cost of utility service as the metric for demonstrating financial viability, only the SLCWRF biogas cogeneration was able to meet this cost effectiveness threshold. An operational change would allow DPU to operate both 700-kW engines to utilize all the biogas produced by the plant with no additional capital investment. This technology option proved cost effective whether both engines were operated using biogas or supplemented with natural gas to maximize generation capacity.

Table 9-1. Economic Ranking of Renewable Energy Projects
(Net Present Value of the Cost of Utility Service)

Project Site	Type of Power Technology	Use of Generation	Overnight Capital	Non-Fuel Operating Expense	Cost of Utility Service Present Value $Millions			Levelized Cost
			2014$ Millions	2014$ Millions	$0 per MTCO2e	$25 per MTCO2e	$50 per MTCO2e	$ per MWh
SLCWRF	Existing Recip (Biogas)	Schedule 31	$0.000	$76.579	($1.458)	($1.996)	($2.533)	$26.50
SLCWRF	Existing Recip (Biogas/NG)	Schedule 31	$0.000	$109.272	($0.273)	(0.697)	($1.120)	$35.50
PRV Station B11-R13	Micro-Hydro	Virtual Net Metering	$0.999	$0.015	($0.188)	($0.515)	($0.841)	$55.50
Mountain Dell Dam	Hydroelectric	Net Metered	$1.551	$0.019	$0.355	$0.064	($0.228)	$92.00
15th East Reservoir	Solar PV	Net Metered	$0.920	$0.013	$0.426	$0.314	$0.202	$153.50
PRV Station B11-R13	Micro-Hydro	Schedule 37	$0.999	$0.015	$0.585	$0.258	($0.068)	$55.50
DPU Office	Heat Recovery	N/A	$0.695	$0.000	$0.602	$0.584	$0.566	N/A
Terminal Park Reservoir	Solar PV	Virtual Net Metering	$11.292	$0.150	$2.354	$0.898	($0.559)	$139.50
Terminal Park Reservoir	Solar PV	Schedule 37	$11.292	$0.150	$10.155	$8.699	$7.242	$139.50

The economic analysis also included a sensitivity analysis that incorporated a cost of carbon into the cash flow analysis to account for potential future GHG regulations and the additional costs it would add to electricity generated from fossil fuels. The assumed cost of carbon for this sensitivity analysis was $25/MTCO$_2$e and $50/MTCO$_2$e. The economic viability of the six projects improved when a price for carbon dioxide was incorporated into the cash flow analysis to account for future fuel price and regulatory risk of GHG regulations. The point to be made about the results of this price sensitivity scenario is that DPU can view the development, generation, and use of electricity from on-site renewable energy projects as a hedge against fuel and energy price increases due to future GHG regulations.

A second sensitivity analysis assumed the generation from the PRV station B11-R13 and Terminal and Park Reservoirs could be used to offset electricity consumed at other DPU facilities through an alternative net metering arrangement (which is not currently available in Utah). Under this assumption, NPV of the PRV Station B11-R13 project exceeds the value of utility service provided by RMP under all cost-of-carbon regulation scenarios. The Terminal and Park Reservoirs solar PV project was still uneconomical under the $0 and $25/MTCO$_2$e cost assumptions but became economically viable when a price of $50/MTCO$_2$e was incorporated into the cash flow analysis. Economics of all the projects evaluated could be improved through DPU adopting some form of third party alternative financing such as a lease or a PPA.

9.2 GHG Emissions

Considering the six renewable energy projects from the standpoint of their contribution to reducing DPU's GHG emissions footprint, the Terminal and Park Reservoirs project has the biggest impact by avoiding 3,381 $MTCO_2e$. This represents approximately 13 percent of the GHG emissions associated with DPU's consumption of purchased electricity and natural gas. The two SLCWRF cogeneration options, where biogas and biogas plus supplemental natural gas are burned to enable the existing engines to run a higher capacity factors, contribute the next largest GHG emissions reductions, avoiding 1,553 and 1,233 $MTCO_2e$.

If DPU developed all six renewable energy projects, it is estimated it could reduce its GHG emissions footprint by 6,228 $MTCO_2e$, or 25 percent.

Table 9-2. Estimated Avoided GHG Emissions by Project

Project Site	Type of Power Technology	Use of Generation	Average Annual Generation	Annual GHG Emissions
			MWh	MTCO2e
SLCWRF	Existing Recip (Biogas)	Schedule 31	2,553	1,553
SLCWRF	Existing Recip (Biogas/NG)	Schedule 31	3,642	1,233
PRV Station B11-R13	Micro-Hydro	Virtual Net Metering	773	582
Mountain Dell Dam	Hydroelectric	Net Metered	690	520
15th East Reservoir	Solar PV	Net Metered	335	252
PRV Station B11-R13	Micro-Hydro	Schedule 37	773	582
DPU Office	Heat Recovery	None	(124)	41
Terminal Park Reservoir	Solar PV	Virtual Net Metering	4,489	3,381
Terminal Park Reservoir	Solar PV	Schedule 37	4,489	3,381

9.3 Rate Schedule Assessment

The regulatory rate schedule assessment evaluated tariff options at each of the renewable energy project sites to determine what tariff rate options were available and would maximize the economic benefits of the proposed renewable energy projects.

The first question addressed was whether the site was on the most appropriate tariff given existing consumption of electricity. Two sites, Mountain Dell and the 15th East Reservoir, are currently receiving power on Schedule 6A, a “time-of-use” tariff, that charges higher rates for electricity consumed during “on-peak” hours and charges significantly lower rates during off-peak hours. In the absence of a renewable energy project at either site, Schedule 6A may not be the appropriate rate schedule or offer the best pricing.

The next question considered at each potential renewable energy site was whether the project would produce electricity that would contribute to meeting load or would generate excess at the site. If excess generation is likely from the new renewable project then options for selling electricity back to RMP were evaluated and considered in the context of maximizing the value DPU would receive for the additional generation.

Based on price, the most advantageous rate RMP currently offers for renewable energy projects is Schedule 135—Net Metering. This tariff is offered to customers with on-site renewable facilities to be connected to the grid and receive credit for excess electricity produced but not consumed at the site. Thus the customer is billed for their "net usage" over the course of a month.

Additionally, for the cogeneration development at the SCLWRF, or the renewable energy projects at the Terminal and Park Reservoirs, 15th East Reservoir, or the B11-R13 PRV station, excess sales to the grid are currently governed by either Schedule 37 (less than 1-MW for cogeneration or less than 3-MW for other renewable projects), or Schedule 38 (greater than 1-MW for cogeneration or greater than 3-MW for other renewable projects). In either case, selling electricity to the grid serves as an important offset to the capital investment incurred with the renewable generation development.

Other rate considerations include the new Schedule 32, which would allow DPU to source a large portion of its electrical service from renewable resources obtained from sources other than RMP. This rate will soon be finalized by the Public Service Commission, and it will offer an alternative option for DPU. The rate has a 2-MW threshold, so aggregation of generation from smaller facilities will be critical for all projects except the Terminal and Park Reservoirs. DPU could aggregate a portfolio of renewable energy sites located throughout Salt Lake City which collectively meet the 2-MW threshold.

9.4 Financing

There are opportunities to leverage DPU's available funds with other funding sources to lower the upfront capital costs and accelerate the deployment of City-owned renewable energy projects. All of the funding sources and financing mechanisms identified by the Consultant Team are viable options for lowering the upfront capital investment required by DPU. Moreover, from the perspective of DPU, lowering the capital investment will improve the economic viability of the projects that receive supplemental funding.

10.0 RECOMMENDATIONS

10.1 Renewable Energy Projects

Based on the analysis conducted by the project team, the following recommendations are offered for action in the near-term:

1. Salt Lake City Wastewater Reclamation Facility

The SLCWRF's existing cogeneration units offer the best and most cost-effective near-term opportunity for DPU to increase the generation of electricity from renewable energy sources and significantly reduce its carbon footprint. DPU should:

- Implement changes in the operations of the existing cogeneration engines at the site. There is sufficient biogas produced at the site to increase utilization of the existing engines by 50percent without running up against limitations placed on the amount of electricity the SLCWRF can produce under RMP's Tariff Schedule 31.
- More fully utilize existing digester gas production capacity by incorporating a fats, oils and grease (FOG) collection program and add this waste stream to the digesters at the SLCWRF. This would increase the production of biogas and enable the cogeneration engines to operate at near capacity.
- In the absence of a FOG program, SLCWRF should supplement the biogas burned by the cogeneration engines with natural gas. While the GHG emissions reduction benefits are decreased, burning natural gas in combination with biogas is still economic from a cost of utility service perspective.
- Evaluate the regulatory opportunity and economics of generating excess power for sale to RMP under Schedules 37 or 38, or to deliver excess generated electricity to one of DPU's other electricity loads under Schedule 32.

2. 15th East Reservoir Site

The 15th East Reservoir site is an excellent candidate for a solar PV installation from a location, resource, and technology standpoint. A 274-kW solar installation was evaluated at the 15th East Reservoir site and proved to be uneconomical from a NPV cost of utility service perspective. However, the 274-kW system would generate almost five times more electricity than is necessary to meet the needs of the reservoir's operations. A net-metered, 25-kW installation sized to offset on-site electricity usage would significantly reduce the upfront capital costs and improve the economic viability of the project. This site is a strong candidate for a solar PV project and additional analysis should be conducted by DPU to further evaluate design alternatives, regulatory strategies, and alternative financing options that could improve its economic viability. DPU should evaluate:

- Whether the electric service at the 15th East Reservoir site could be aggregated with electric meters at the adjacent Rice Eccles Stadium to take full advantage of net metering and the 274-kW solar generation capacity the site would support.
- The economic advantages of a third party project financing mechanism such as a lease or a PPA. This would allow DPU to take advantage of a federal tax incentive through a third-party ownership structure, which could reduce the cost by 30 percent and improve the economics of the project.
- Evaluate the economics of a solar PV system that is designed to optimize the size of the system based on on-site load. At a minimum, it will reduce the upfront capital costs of the project and significantly improve the NPV cost of utility service over the life of the project.

3. Mountain Dell Dam Hydroelectric Project

The Mountain Dell Reservoir hydroelectric project is considered an attractive site for development because of the ease of interconnection to existing load, and the potential for the hydroelectric power system to be net metered and offset 75 percent of the power currently purchased from RMP at $0.1128 per kWh. The project proved economical on a NPV basis when price of \$50/MTCO$_2$e is assumed in the cash flow analysis. There is an opportunity to significantly improve the financial viability of this project and reduce DPU's upfront capital costs through a lease or a PPA. DPU should investigate this type of arrangement before the federal tax incentives expire at the end of 2016.

4. Pressure Release Valve Station B11-R13 Micro-Hydroelectric Project

Like the Mountain Dell hydroelectric project, the PRV B11-R13 micro-hydro project was economically viable when a price of \$ 50/MTCO$_2$e was used in the cash flow analysis to account for the potential costs of future GHG regulations. Because of the number of PRV stations operated by DPU, the successful demonstration of the technical viability of this technology at the PRV B11-R13 station site creates the opportunity to develop many more micro-hydroelectric sites in the DPU water system. From the standpoint of DPU, the economics of this project and others could be improved further by leveraging the federal renewable energy tax incentives to attract a third party development partner who could take advantage of the tax credits, and financing that would offset a portion of the upfront capital costs of the project.

5. Terminal and Park Reservoir Solar PV Project

The Terminal and Park Reservoir site could support a 3.5-MW solar PV installation capable of generating an annual average of 4,490,000 kWh. The only circumstance where the Terminal Park Reservoirs site would provide lower cost electricity service compared to RMP is by assuming an alternative net metering tariff is available to DPU at the equivalent of the average retail rate for Schedule 6A (i.e., 11.28 cents per kWh), and including a \$50/MTCO$_2$e in the cash flow analysis. Like the other renewable energy projects that require a major capital investment, there is an opportunity to significantly improve the financial viability of this project and reduce DPU's up-front capital costs through a lease or a PPA with a third party who can take advantage of the federal tax incentives.

This is the single largest renewable energy project opportunity among the 151 project sites evaluated and it provides the greatest opportunity to offset RMP electricity purchases and reduce DPU's carbon footprint. DPU should investigate the opportunity to enter into third party alternative financing arrangement before the federal tax incentives expire at the end of 2016 as a strategy to improve the economics of the project.

6. Solar Photovoltaic (PV) Rooftop Projects

Solar PV rooftop projects scored very high relative to all projects in the detailed site evaluations but were not selected for regulatory and economic analysis in Phase II. PV rooftop systems offer the opportunity to offset each kWh generated at the full costs of power delivered to DPU facilities by local electricity providers, and are scalable to the available space on a building. DPU should conduct a more complete evaluation of all available roof space and the economic viability of these systems. Moreover, because of the renewable energy opportunity offered by solar PV, Salt Lake City government should consider adopting construction standards for new and renovated buildings that require consideration of solar PV and integrate solar-ready building techniques into future construction or renovation. To improve the economics of rooftop solar, DPU should apply for the Utah Solar Incentive Program. This program awards an incentive for solar projects through a lottery and will expire after January 2017. DPU should also consider using a PPA to leverage the 30 percent federal tax credit that expires in 2016.

7. DPU Main Office Wastewater Heat Recovery Project

A wastewater heat recovery project adjacent to DPU's main office in Salt Lake City would utilize a heat exchanger/heat pump to extract heat from wastewater flowing in the sewer trunkline along West Temple, and provide supplemental space heating to DPU's main office. The heat exchanger/heat pump system for this project can also be configured to provide cooling during the summer months. The screening level data and design parameters used for this analysis did not provide sufficient detail to enable evaluation of the cooling capabilities of this technology. If DPU is interested in a more detailed investigation of this technology, it is recommended that the City evaluate the cooling capability of reconfiguring wastewater heat recovery technology to be tied to the existing HVAC system.

10.2 Regulatory

1. Salt Lake City Wastewater Reclamation Facility

SLCWRF is currently constrained from operating its two 700 kW-reciprocating engine cogeneration system at full capacity due to prohibitions against generation exceeding load at the site. In order to take full advantage of the economic and environmental benefits of available biogas and underutilized cogeneration capacity, DPU should evaluate the regulatory implications and economics of generating excess electricity under the various rate schedules associated with its on-site generation capacity, i.e., Schedules 31 and 9. Neither Schedule 31 nor Schedule 9 allows net metering or selling excess power back to RMP. However, as a facility taking service under Schedule 31, SLCWRF might

be able to sell excess electricity back to the utility at wholesale "avoided costs" rates using either Schedule 37 (if the capacity sold is less than 1-MW) or Schedule 38 (if greater than 1-MW).

2. Mountain Dell Hydroelectric Project

The Parley's Canyon Water Treatment Plant is currently receiving electricity service through Schedule 6A. Based on the load shape of electricity use at this site, Schedule 6A might not be best tariff. DPU should assess whether the water treatment plant is eligible for a different tariff. If the hydroelectric project is developed at Mountain Dell, this site is a good candidate for net metering on Schedule 135.

3. Pressure Release Valve Station B11-R13 Micro-Hydroelectric Project

A micro-hydro project installed at the PRV station B11-R13 will generate more electricity than there is load at the site. DPU should certify this PRV project as a QF and make it eligible to sell power back to RMP under Schedule 37.

4. Electric Service Schedule 32

End use customers utilizing Schedule 32 must contract to take more than 2-MW of electricity delivery; however, the law permits multiple renewable energy facilities to deliver electricity to a single contract customer. Given the multiple renewable opportunities identified by this study, DPU should evaluate whether or not it would be feasible and economic to build a 2-MW portfolio of projects to serve DPU loads under this tariff.

5. Alternative Net Metering

Alternative net metering policies improved the economics of the Terminal and Park Reservoirs, and PRV B11-R13 projects. As a leader and advocate for clean energy and the environment, Salt Lake City should consider advocating for regulatory policies that allow the City to use credits generated at one facility to offset electrical bills at another facility.

10.3 Alternative Financing

1. Utah Solar Incentive Program

Due to the number of Solar PV development opportunities, DPU should apply for the Utah Solar Incentive Program for both small solar PV (less than 25-kW) and large solar projects up to 1-MW to fund projects. The current program will sunset in 2017.

2. Lease and Power Purchase Agreements

There are alternative financing opportunities to leverage DPU's available funds with other funding sources to lower the upfront capital costs and accelerate the deployment of City-owned renewable energy projects. DPU should consider lease structures or PPAs as a financing mechanism that reduces cost through tax incentives. The current 30 percent federal tax credit is set to revert to 10 percent at the end of 2016.

Appendix A

Phase I Evaluation Matrix

				Generation Points			Site Charateristics Points													Environmental Points						
Tank Name	Capacity (kW)	Annual AC Energy (kWh)	On-Site or Adjacent Loads	Initial Points	Weighting Factor	Weighted Points	Potential to Offset Existing DPU Load	Initial Points	Weighting Factor	Potential to Interconnect	Initial Points	Weighting Factor	Distance to Distribution Infrastructure	Initial Points	Weighting Factor	% DPU Load Displaced	Initial Points	Weighting Factor	Weighted Points	Impact	Acceptance	Initial Points	Weighting Factor	Weighted Points	Total Poiint	Comments
Water Tank/Reservoir - Roof Mount																										
Terminal Reservoirs/Park Reservoir	1,562	2,280,520	Wells 3580 E #4 & #5	5	5	25	Yes	3	2	Yes	5	2	<0.2 mi	4	4	100	5	2	42	Negligible	100%	5	5	25	92	
Baskin Reservoir	395	576,700	Bonneville PS	4	5	20	Yes	3	2	Yes	5	2	<0.2 mi	4	4	34	2	2	36	Negligible	100%	5	5	25	81	
15th East Reservoir	290	423,400	500 S Well & University PS	3	5	15	Yes	5	2	Yes	5	2	<0.1 mi	5	4	No data	1	2	42	Negligible	100%	5	5	25	82	
Military Reservoir	256	373,760	Military PS	3	5	15	Yes	5	2	Yes	5	2	<0.1 mi	5	4	15	1	2	42	Major	<50%	0	5	0	57	Reservoir is used as a park
Victory Road Reservior	248	362,080		3	5	15	No	0	2	Yes	5	2	<0.3 mi	3	4	0		2	22	Negligible	100%	5	5	25	62	
Wilson Reservoir	241	351,860	Arlington Hills PS	3	5	15	Yes	5	2	Yes	5	2	<0.1 mi	5	4	25	2	2	44	Negligible	100%	5	5	25	84	
Marcus Reservoir	190	277,400		3	5	15	No	0	2	Yes	5	2	<0.1 mi	5	4	0		2	30	Negligible	100%	5	5	25	70	
Morris Reservoir	176	256,960	North Bench PS	3	5	15	Yes	5	2	Yes	5	2	<0.1 mi	5	4	86	5	2	50	Negligible	100%	5	5	25	90	
McEntire Reservoir	142	207,320		2	5	10	No	0	2	Yes	5	2	<0.1 mi	5	4	0		2	30	Major	<50%	0	5	0	40	Reservoir is used as a park
13th East Reservoir	114	166,440		2	5	10	No	0	2	Yes	5	2	<0.1 mi	5	4	0		2	30	Major	<50%	0	5	0	40	Reservoir is used as a park
Ensign Downs Lower Tank	105	153,300	Ensign Downs PS	2	5	10	Yes	5	2	Likely	3	2	<0.3 mi	3	4	No data	1	2	30	Negligible	100%	5	5	25	65	
Tanner Reservoir	67	97,820	Dyers Inn Well	1	5	5	Yes	5	2	Yes	5	2	<0.1 mi	5	4	4	1	2	42	Negligible	100%	5	5	25	72	Low generation but DPU load on-site
Granite Oaks Tank/Telford Reservoir	54	78,840	Granite Oaks PS	1	5	5	Yes	5	2	Yes	5	2	<0.1 mi	5	4	No data	1	2	42	Negligible	100%	5	5	25	72	Low generation but DPU load on-site
Tavaci Tank	47	68,620	Tavici PS	1	5	5	Yes	2	2	Maybe	1	2	<0.5 mi	1	4	No data	1	2	12	Negligible	100%	5	5	25	42	Low generation but DPU load on-site
Mt Opympus Tanks	45	65,700	Mount Olympus PS	1	5	5	Yes	5	2	Yes	5	2	<0.1 mi	5	4	9	1	2	42	Negligible	100%	5	5	25	72	Low generation but DPU load on-site
East Bench Tanks	38	55,480	Carrigan Cove PS	1	5	5	Yes	5	2	Yes	5	2	<0.1 mi	5	4	69	4	2	48	Negligible	100%	5	5	25	78	Low generation but DPU load on-site
Eastwood Tanks	14	20,440	Eastwood PS	1	5	5	Yes	5	2	Yes	5	2	<0.1 mi	5	4	4	1	2	42	Negligible	100%	5	5	25	72	Low generation but DPU load on-site
Millcreek Tank	2	2,920	Lower Boundary PS	1	5	5	Yes	5	2	Yes	5	2	<0.1 mi	5	4	1	1	2	42	Negligible	100%	5	5	25	72	Low generation but DPU load on-site
Buildings - Roof Mount																										
Boeing	733	1,070,180	Building Load	5	5	25	Yes	5	2	Yes	5	2	<0.1 mi	5	4	No data	1	2	42	Negligible	100%	5	5	25	92	
XPEDX	456	665,760	Building Load	4	5	20	Yes	5	2	Yes	5	2	<0.1 mi	5	4	No data	1	2	42	Negligible	100%	5	5	25	87	
Highland High School	333	486,180	Building Load	3	5	15	Yes	5	2	Yes	5	2	<0.1 mi	5	4	No data	1	2	42	Negligible	100%	5	5	25	82	
Roberts Restaurant and Adjacent Building	267	389,820	Building Load	3	5	15	Yes	5	2	Yes	5	2	<0.1 mi	5	4	No data	1	2	42	Negligible	100%	5	5	25	82	
410 N. Wright Brothers Drive	228	332,880	Building Load	3	5	15	Yes	5	2	Yes	5	2	<0.1 mi	5	4	No data	1	2	42	Negligible	100%	5	5	25	82	
Salt Lake City Sports Complex	187	273,020	Building Load	3	5	15	Yes	5	2	Yes	5	2	<0.1 mi	5	4	No data	1	2	42	Negligible	100%	5	5	25	82	
The Leonardo	91	132,860	Building Load	2	5	10	Yes	5	2	Yes	5	2	<0.1 mi	5	4	No data	1	2	42	Minor	90%	4	5	20	72	
Sorenson Multicultural and Unity Fitness Center	58	84,680	Building Load	1	5	5	Yes	5	2	Yes	5	2	<0.1 mi	5	4	No data	1	2	42	Negligible	100%	5	5	25	72	
SLCDPU Buildings	57	83,220	Building Load	1	5	5	Yes	5	2	Yes	5	2	<0.1 mi	5	4	7	1	2	42	Negligible	100%	5	5	25	72	
Open Parcel - Ground Mount																										
South Lift	299	436,540	South Sewer LS	3	5	15	Yes	5	2	Yes	5	2	<0.1 mi	5	4	100	5	2	50	Negligible	100%	5	5	25	90	
Smith & Loveless	85	124,100	Smith & Loveless and 4000 W Sewer LS	2	5	10	Yes	5	2	Maybe	1	2	<0.3 mi	5	4	No data	1	2	34	Moderate	100%	1	5	5	49	
Concord Lift	79	115,340	Concord Sewer LS	2	5	10	Yes	5	2	Yes	5	2	<0.1 mi	5	4	100	5	2	50	Negligible	100%	5	5	25	85	
6200 S. Well	63	91,980	6200 S Well & 6200 S Irrigation PS	1	5	5	Yes	5	2	Yes	5	2	<0.1 mi	5	4	5	1	2	42	Negligible	100%	5	5	25	72	
Greenfield Village	51	74,460	Greenfield Village Well	1	5	5	Yes	5	2	Yes	5	2	<0.1 mi	5	4	6	1	2	42	Negligible	100%	5	5	25	72	

				Generation Points			Site Charateristics Points													Environmental Points						
Facility ID	Capacity (kW)	Annual Generation (kWh)	On-Site or Adjacent Loads	Initial Points	Weighting Factor	Weighted Points	Potential to Offset Existing DPU Load	Initial Points	Weighting Factor	Potential to Interconnect	Initial Points	Weighting Factor	Distance to Distribution Infrastructure	Initial Points	Weighting Factor	% DPU Load Displaced	Initial Points	Weighting Factor	Weighted Points	Impact	Acceptance	Initial Points	Weighting Factor	Weighted Points	Total Poiint	Comments
PRV																										
D74-DV1	359	1,310,352		5	5	25	No	0	2	Maybe	1	2	<0.3 mi	3	4	0	0	2	14	Negligible	100%	5	5	25	64	
B35-R18	422	1,539,757		5	5	25	No	0	2	Yes	5	2	<0.1 mi	5	4	0	0	2	30	Negligible	100%	5	5	25	80	
B11-R13	292	1,064,622		5	5	25	No	0	2	Yes	5	2	<0.1 mi	5	4	0	0	2	30	Negligible	100%	5	5	25	80	
C41-R20	281	1,025,114		5	5	25	No	0	2	Yes	5	2	<0.1 mi	5	4	0	0	2	30	Negligible	100%	5	5	25	80	
B6-R73	266	970,091		4	5	20	No	0	2	Yes	5	2	<0.1 mi	5	4	0	0	2	30	Negligible	100%	5	5	25	75	
D69-R40	63	228,660		2	5	10	No	0	2	Yes	5	2	<0.1 mi	5	4	0	0	2	30	Negligible	100%	5	5	25	65	
A23-R5	59	216,797		2	5	10	No	0	2	Yes	4	2	<0.1 mi	5	4	0	0	2	28	Negligible	100%	5	5	25	63	
C1-R74	54	196,973		2	5	10	No	0	2	Yes	5	2	<0.1 mi	5	4	0	0	2	30	Negligible	100%	5	5	25	65	
F78-CR28	41	151,340		2	5	10	No	0	2	Maybe	1	2		1	4	0	0	2	6	Negligible	100%	5	5	25	41	
G35-CR53	36	131,639	Private Well	2	5	10	Yes	4	2	Yes	5	2	<0.1 mi	5	4	0	0	2	38	Negligible	100%	5	5	25	73	
G38-CR57	17	62,052	7800 S PS	1	5	5	Yes	4	2	Yes	5	2	<0.1 mi	5	4	7	1	2	40	Negligible	100%	5	5	25	70	Low generation but DPU load on-site
Surface Water																										
Mountain Dell Dam	410	2,370,536	Parley's WTP	5	5	25	Yes	5	2	Yes	5	2	<0.1 mi	5	4	100	5	2	50	Minor	100%	4.5	5	22.5	98	
Big Spill	15	65,520	On-site pump, lighting and gates	1	5	5	Yes	5	2	Likely	3	2	<0.4 mi	2	4	100	5	2	34	Minor	100%	4.5	5	22.5	62	Low generation but DPU load on-site

Appendix B

Technical Memorandum – Cogeneration Assessment
Carollo Engineers

SALT LAKE CITY
DEPARTMENT OF PUBLIC UTILITIES

TECHNICAL MEMORANDUM
COGENERATION ASSESSMENT

REVISED FINAL
November 2014

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SALT LAKE CITY
DEPARTMENT OF PUBLIC UTILITIES

TECHNICAL MEMORANDUM
COGENERATION ASSESSMENT

TECHNICAL MEMORANDUM

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1.0 INTRODUCTION

1.1 Background

The Salt Lake City Water Reclamation Facility (SLCWRF) treats up to 56 million gallons of wastewater a day and is owned and operated by the Salt Lake City Department of Public Utilities (SLCDPU). SLCWRF is located on the north end of the City at 2300 North, between Redwood Road on the West and the Oil Drain Canal on the East. SLCWRF was originally constructed in the early 1960s, and has undergone numerous upgrades and expansions since then.

Currently, a combined trickling filter and activated sludge process is used at SLCWRF to remove organic wastes and treat wastewater prior to its release back to the environment. Waste activated solids are co-settled with primary solids in the primary clarifiers, thickened through gravity thickeners, mixed with scum collected from process basins and stabilized in anaerobic digesters. After digestion, solids are dried in solar dying beds and hauled away for use as daily cover at the county landfill.

Digester gas, consisting of mostly methane, is collected and cleaned prior to combustion in engine generators for energy recovery and a boiler for digester heating needs. Energy recovered through the combustion of digester gas offsets the amount of power that must be purchased from the local energy utility. An excess digester gas above what can be used in the engine generators or boiler is destroyed by flare.

The purpose of this technical memorandum is to provide an assessment of cogeneration at SLCWRF as part of a larger citywide review of possible alternative energy projects.

1.2 Scope

The following alternatives were developed and evaluated based on life cycle costs and other evaluation parameters.

- Alternative 1 – Use Existing Cogeneration Engines – Run one engine with no natural gas supplementation.
- Alternative 2 – Use Existing Cogeneration Engines – Run two engines with no natural gas supplementation.
- Alternative 3 – Use Existing Cogeneration Engines – Run two engines with natural gas supplementation.

- Alternative 4 – Replace Existing Engines with a New Engine.
- Alternative 5 – Replace Existing Engines with New Microturbine.
- Alternative 6 – Replace Existing Engines with New Fuel Cell.

Each of these alternatives was evaluated based on digester gas production from two treatment process configurations, the current wastewater treatment process and a future biological nutrient removal (BNR) process.

2.0 BACKGROUND

2.1 Existing Cogeneration System

The existing system consists of two 700-kilowatt (kW) engine-generators. The cogeneration system provides electrical energy production and heat for the anaerobic digesters. SLCDPU's desire to minimize future energy costs, limit their greenhouse gas emissions, and better utilize the renewable energy available has prompted this cogeneration assessment. Allowing the existing system to become non-operative due to age, lack of available parts, or catastrophic failure will result in significantly higher energy costs, an increase in associated energy related greenhouse gas emissions, and will put the SLCDPU at greater economic risk due to potential volatile energy prices.

2.2 Current Gas Production

For 2013, SLCWRF's monthly gas production has ranged from 224,000 cf/d to 466,000 cf/d and averaged 358,000 cf/d (Table 1). The cogeneration system can produce a portion of the SLCWRF demands, but power must still be purchased.

The specific gas production rate can then be estimated by dividing the gas production by the measured volatile solids reduction (VSR). Generally, the specific gas production rate falls within a range of 12 to 18 cf/lb VS destroyed. Numbers outside of this range can indicate problems with either the gas meters or the sludge meters.

SLCWRF uses two different methods to measure their digester feed flow (a flow meter and a stroke counter) and two different methods to measure their digester feed total solids (TS) (density meter and lab samples) from both of their gravity thickeners. By combining these two different sludge flows and two different total solids concentrations, SLCWRF can compute four different digester feed TS loads as summarized below:

- Sludge flow meter combined with the lab sample for TS (FM-LS)
- Sludge flow meter combined with the density meter reading for TS (FM-DM)
- Stroke counter converted to flow combined with the lab sample for TS (SC-LS)

- Stroke counter converted to flow combined with the density meter reading for TS (SC-DM).

Table 1	2013 Monthly Average Gas Production Cogeneration Assessment SLCDPU
Month	**Monthly Average Gas Production, cf/d**
January	348,816
February	455,833
March	466,207
April	448,769
May	418,890
June	334,578
July	273,332
August	246,574
September	223,786
October	347,566
November	303,693
December	430,773
2013 Average	**358,235**

The digester feed volatile solids (VS) load was then calculated by multiplying each of the four different feed TS loads by the lab measured ratio of digester VS to TS resulting in the same four different digester feed VS load calculations.

It was assumed that the flow into the digester equaled the flow out of the digester and so the same two flow measurements, FM-LS and SC-LS, were used to calculate two digester VS loads.

The mass of volatile solids reduced (VSR) was then calculated four different ways by subtracting the two different digester VS loads from the four different digester feed VS loads:

Digester Feed VS (FM-LS) – Digester Sludge VS (FM-LS)

Digester Feed VS (FM-DM) – Digester Sludge VS (FM-LS)

Digester Feed VS (SC-LS) – Digester Sludge VS (SC-LS)

Digester Feed VS (SC-DM) – Digester Sludge VS (SC-LS)

Table 2 summarizes the monthly average VSR using the four different calculation methods. SLCWRF staff generally believes that the SC-LS data is the most accurate. As shown in Table 2, the yearly average VSR ranges from a low of 19,023 ppd (SC-LS) to a high of 24,488 ppd (FM-DM).

Table 2 2013 Monthly Average Volatile Solids Reduction
Cogeneration Assessment
SLCDPU

Month	VSR, ppd FM- LS	VSR, ppd FM-DM	VSR, ppd SC-LS	VSR, ppd SC-DM
January	23796	30384	22423	28205
February	27206	22490	18426	14694
March	27304	26749	23880	23761
April	26352	23073	24844	20913
May	28254	26860	23055	21986
June	28480	28805	19488	19624
July	21454	24381	17006	19209
August	16072	18704	13280	15462
September	15895	18241	11338	13329
October	22956	25878	17903	19994
November	22844	21231	15509	14623
December	21179	27245	19472	24891
2013 Average	23592	24488	19023	19649
Average Difference from SC-LS	+24%	+29%	--	+3%

The estimated specific gas production rate can be estimated by dividing the monthly gas production by the monthly VSR. These values are summarized in Table 3. The 2013 average specific gas production rate ranged from a low of 14.7 cf/lb for the FM-DM samples to a high of 19.1 cf/lb for the SC-LS samples. The VSR calculated using the flow meter yield specific gas production rates that are within the typical range, while the VSR calculated

using the stoke counter yield specific gas production rates that are slightly higher than the typical range. Since the SLCDPU has the most confidence in their SC-LS measurements, a specific gas production rate of 19.1 cf/lb was selected for planning purposes.

Table 3 2013 Monthly Average Specific Gas Production Rates
Cogeneration Assessment
SLCDPU

Month	cf/lb FM-LS	cf/lb FM-DM	cf/lb SC-LS	cf/lb SC-DM
January	14.7	11.5	15.6	12.4
February	16.8	20.3	24.7	31.0
March	17.1	17.4	19.5	19.6
April	17.0	19.5	18.1	21.5
May	14.8	15.6	18.2	19.1
June	11.7	11.6	17.2	17.0
July	12.7	11.2	16.1	14.2
August	15.3	13.2	18.6	15.9
September	14.1	12.3	19.7	16.8
October	15.1	13.4	19.4	17.4
November	13.3	14.3	19.6	20.8
December	20.3	15.8	22.1	17.3
2013 Average	15.3	14.7	19.1	18.6

2.3 Digester Gas Production Projections

The gas production was estimated for current flows and loads for three different operational schemes:

Co-thickening – No biological nutrient removal (BNR): Currently the plant co-thickens WAS in their primary clarifiers. The 2014 WRF Capacity Evaluation (Water Works Engineering) reports a fairly high primary clarifier TSS removal rate of 75% that they suggest could be due to the co-thickening operation. In this configuration, the digester feed VS is

around 28,000 ppd (as calculated using the SC-LS method) and they achieve approximately 66% VSR.

Separate thickening/mechanical dewatering – No BNR: In this configuration, the plant would be operated as it is currently configured except that the WAS would be separately thickened and the sludge drying beds would be replaced with mechanical dewatering. For this configuration, a lower primary clarifier TSS removal rate was assumed of 69%. Additionally, 95% capture was assumed for the WAS thickening and 90% capture was assumed for the mechanical dewatering. This configuration resulted in a higher VS load to the digesters and a slightly lower VSR due to a increase in the WAS to PS ratio in the digester feed.

Separate thickening – BNR: In this configuration, the plant would be operated for BNR with separate thickening of the WAS. This configuration resulted in a lower VS load than the separate thickening configuration with no BNR due to the longer solids retention time in the aeration basins, which resulted in a decrease in the VS load to the digester and a decrease in the degradability of the WAS VS. A low and a high gas production were calculated for this configuration because there was concern that conversion to BNR could reduce the specific gas production rate. The high gas production rate was estimated assuming a specific gas production rate of 19.1 cf/lb and a low gas production rate was estimated assuming a specific gas production rate of 15 cf/lb.

Table 4 summarizes the 2013 estimated gas production from each of these configurations. As shown in Table 4, separate thickening is estimated to increase the gas production by approximately 20% and operation in a BNR configuration (with separate thickening) is estimated to decrease the gas production by approximately 7%. Future gas production was estimated for each configuration by increasing the digester VS load by the projected increase in the equivalent population. 2040 gas production rates were estimated to range from 316,000 cf/d for BNR with the low specific gas production rate of 15 cf/d to a high of 538,000 cf/d with no BNR.

3.0 COGENERATION TECHNOLOGIES

Cogeneration equipment was sized to efficiently and economically utilize the digester gas generated at SLCWRF. Various types of cogeneration technologies can be employed to produce power from digester gas. The following section summarizes each of the technologies and presents the specific model and size of the technology considered for SLCWRF. Manufacturer information from equipment vendors is included in Appendix A for Reference.

Table 4	Estimated Gas Projection Cogeneration Assessment SLCDPU		
Year	**Current Configuration No BNR**	**Separate Thickening No BNR**	**Separate Thickening BNR**
2013	Dig Feed = 28,000 ppd VSR = 67% VSR = 19,000 ppd Gas = 358,000 cf/d	Dig Feed ~ 35,000 ppd VSR ~ 64% VSR ~ 22,000 ppd Gas ~ 425,000 cf/d	Dig Feed ~ 31,000 ppd VSR ~ 56% VSR ~ 17,000 ppd Gas ~ 332,000 cf/d (high) Gas ~ 261,000 cf/d (low)
2040	NA	Gas ~ 538,000 cf/d	Gas ~ 400,000 cf/d (high) Gas ~ 316,000 cf/d (low)

3.1 Conventional Reciprocating Engines

Reciprocating engines, developed more than 100 years ago, were the first of the fossil fuel-driven distributed generation (DG) technologies. Reciprocating engines can be found in applications ranging from fractional horsepower units to 60-megawatt (MW) base load electric power plants.

The engine cooling water and exhaust heat from reciprocating engines can be recovered in heat exchangers and used to provide heat for digester heating and/or facility hot water heating. Several lean burn reciprocating engine suppliers have new generation, high efficiency, and low emission units available for use with biogas including Cummins, Caterpillar (MWM), and GE/Jenbacher. These new engines have efficiencies of approximately 40 percent, which stays nearly constant throughout the typical operating range of 50-100 percent engine load. These engines typically convert approximately 40 percent (as a percentage of fuel input energy) to electrical output and 40-45 percent to heat using recovered energy from the engine cooling water and exhaust heat. The total overall efficiency of these reciprocating engines is approximately 80-85 percent. The engines are lean-burn, spark-ignited, low emission gas engines and have digester gas burning experience. All can be fitted with exhaust after-treatment equipment to control NOx and CO emissions to current and future required levels if required. In addition, the existing engines are relatively new Waukesha low emission engine generators. These engines are < 35% efficient as they are a slightly older generation engine and do not have as sophisticated of control systems. They too can be equipped with exhaust after-treatment equipment to meet current/future emission requirements.

Two alternatives were identified using reciprocating engine technology for each process configuration; the first, continuing to utilize the existing engine generators and the second, utilize a new GE/Jenbacher engine generator unit.

3.2 Microturbine

Microturbines are essentially small gas turbines operating at very high rpm to produce power and heat.

Microturbines are extremely low emission technologies and typically do not require an air permit for operation.

Microturbines evaluated typically convert 29 percent to electrical output (as a percentage of fuel input energy) and 29 percent to recoverable exhaust heat for a total overall efficiency of approximately 58 percent.

There are currently several commercial manufacturers offering microturbine power generating units. Only two of these units (FlexEnergy formally known as Ingersoll Rand and Capstone) have experience utilizing digester gas as a fuel source. FlexEnergy offers 250 kW modular units. The Capstone units come in 30, 65, and multiples of 200 kW sizes.

Ingersoll Rand and Capstone have shipped worldwide more than 100 units operating on both natural gas and digester gas. Several dozens of 30 kW and 70 kW units and two 250 kW units are operating on digester gas. Two 250 kW units are in operation on a medium BTU gas at a Oil/Gas Producer in Grand Isle, LA and eight 250 kW units have recently been sold for operation on a medium BTU gas in both the United States and China.

One alternative was identified for each of the process configurations utilizing new Flex Energy microturbine units.

3.3 Fuel Cells

Fuel cells utilize the hydrogen present in the methane-rich digester gas as a fuel source in an electrochemical process. The process converts the elemental carbon and hydrogen from the methane into carbon dioxide and hydrogen and in the process releases electrons, which are captured as direct current (DC) electricity.

The fuel cells evaluated typically convert, as a percentage of fuel input power, 47 percent to electrical output, and 22 percent to recoverable exhaust heat for a total overall efficiency of approximately 69 percent.

Two manufacturers currently offer fuel cells for large-scale power generation, United Technologies Corporation (UTC) and Fuel Cell Energy (FCE). Both manufacturers have provided fuel cells for applications utilizing digester gas; however, only FCE has units currently in operation. Many of these units operating on biogas are located in California. FCE utilizes a more efficient fuel cell technology than UTC, providing 47 percent fuel-to-

electricity efficiency versus UTC's 37-40 percent. Due to the higher efficiencies and additional experience utilizing digester gas, only FCE units are considered for this evaluation.

As an electrochemical process, fuel cells produce significantly less pollutant byproducts than combustion technologies. Fuel cells have approximately 1/100th the emissions generated by engine-generators.

One alternative was identified for each of the process configurations utilizing a new Fuel Cell Energy fuel cell.

3.4 Alternative Benefit Comparison

A summary of the advantages and disadvantages for the existing cogeneration system and three technology alternatives is included in Table 5.

Table 5 Alternative Benefit Comparison
Cogeneration Assessment
SLCDPU

Alternative	Advantages	Disadvantages
Alternatives 1, 2, & 3 - Existing Cogeneration System	• No change in operation	• Does not take advantage of all the digester gas available onsite or reduce facility carbon footprint
Alternative 4 - Conventional Reciprocating Engines	• Proven technology utilizing biogas for over 40 years • Newer generation engines have very high efficiency • Newer engines can easily meet new strict emission regulations	• Requires dedicated building for sound and weather protection • Frequent operator attention required for operations and maintenance • Requires fuel treatment
Alternative 5 - Microturbine	• Ultra low emissions • Simplified electrical interconnection • Low operator attention for operations and maintenance	• Very lowest electrical efficiency • Requires extensive fuel treatment
Alternative 6 - Fuel Cell Generator Unit	• Ultra Low emissions • Highest efficiency • Simplified electrical interconnection • Low operator attention for operations and maintenance	• Highest O&M costs • Highest capital costs • Requires extremely reliable and robust fuel treatment

4.0 FUNDING SOURCES

The following section outlines funding sources that may be available to SLCDPU to implement potential cogeneration alternatives. Table 6 summarizes applicable programs, depending upon how project procurement/development proceeds.

The applicability of the programs noted in Table 6 depends on many factors including procurement method and ownership and the technology utilized. Some of the programs are grants, some credits, and some loans - choosing the correct combination depends on many factors specific to the project.

Table 6 Funding Summary
Cogeneration Assessment
SLCDPU

Program	Source	Summary
Renewable Energy Production Incentive (REPI)	US DOE	Provides financial incentive payments of 1.5 cents per kWh of electricity produced for sale from renewable sources.
Renewable Electricity Production Tax Credit	US Govt.	Provides a 0.9 cents/kWh corporate tax credit for renewable energy systems (applicability is in question as digester gas fueled systems are not specifically addressed)
Commercial (non government) loan programs	Various	Various funding and loan programs exist outside of the above listed government sponsored programs. These are listed in the attached documentation and range from equipment secured loans to unsecured loans, to guaranty and subsidized loans
Renewable Energy Credits (RECs)	Various	Renewable energy credits can be sold for power generated utilizing renewable fuels. These energy credits (referred to as tags) are sold on an open market and for digester gas; fueled systems can represent income of approximately \$0.0015/kWh. This amount varies with the market, which varies by area in the Country and type of technology utilized.
Clean Renewable Energy Bonds (CREBs)	Various	Various sources of bond financing exist which provide low/no interest financing to municipal entities for renewable energy projects. These allow municipal entities to take advantage of tax credits even though they cannot do so directly. Typically, fees of upwards of 5% of the bond funding proceeds apply for these bond funds.

4.1 Renewable Energy Credits

Renewable energy credits are a mechanism by which energy generated by renewable means can be valued and traded. Users who desire to "purchase" renewable power can purchase renewable energy credits for a certain amount of power that they will utilize.

Entities generating renewable power can get credit for this power (beyond the value of the power) on a $/kWh basis to the grid. The renewable energy credit is a means in which to track power, which has been generated, from renewable sources.

Renewable energy credits can be sold for power generated from renewable fuels. These energy credits (referred to as tags) are sold on an open market. This amount varies with the market, and is dependent upon area of the country and type of technology utilized. While the value is significantly less than newly generated power, even “tags” for power generated in past periods can be sold.

Typically, “tags” are sold through a broker specializing in these credits.

SLCDPU should pursue sale of “tags” for all of the power generated from the cogeneration system.

5.0 LIFE CYCLE COST EVALUATION RESULTS

To evaluate the benefits and costs of these alternatives, both the projected capital costs of the installation and the yearly operations and maintenance (O&M) costs were calculated. The evaluation takes into account the value of, or purchase of electrical power. The method selected for this analysis was to determine the total present worth of the project. Each alternative was then compared. Assumptions used for the life cycle cost analysis are shown in Table 7.

The results of the life cycle cost analysis are presented in Tables 8 and 9 for the current and BNR process digester gas projections.

Total project capital costs, including design and construction costs, for each alternative were estimated. Capital and life cycle costs are presented in Appendix B and C, respectively

5.1 Greenhouse Gas Emissions

The Environmental Protection Agency (EPA) has proposed a mandatory monitoring and reporting rule, for facilities that emit greenhouse gases (GHG) of more than 25,000 metric tons of CO_2 equivalent per year. The greenhouse gases include carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and fluorinated gases. The proposed rule does not affect wastewater treatment process emissions, but does cover onsite combustion sources. Table 10 summarizes the greenhouse gas emissions for each alternative. The GHG emissions are shown for the best-case gas production as a conservative measurement of emissions because more digester gas will be burned onsite. The onsite combustion emissions are the emissions that qualify for the EPA proposed rule. The GHG emissions for all alternatives are below the 25,000 metric ton per year minimum and the SLCDPU will not have to report their emissions. The total GHG emissions include both the emissions from onsite combustion and the electricity purchased offsite. Additionally, the use of the existing

engines was considered with and without natural gas supplementation. A review of all alternatives without natural gas usage is provided in Appendix D.

5.2 Qualitative Summary

Table 11 ranks the cogeneration alternatives utilizing weighted economic and non-economic criteria.

Table 7 Criteria and Financial Assumptions Cogeneration Assessment SLCDPU

Present worth year	2015
First year of evaluation	2016
Project duration, years	20
Inflation (capital costs)	1.80%
Inflation (fuel and electricity costs)	2.85%
Inflation (O&M costs)	1.80%
Gross discount rate	5.00%
Digester Gas LHV, Btu/scf	560
Existing engine availability percentage	90%
New engine availability percentage	90%
New microturbine availability percentage	95%
New fuel cell availability percentage	98%
O&M rate for existing engines alternatives $/kWh	$0.020
O&M rate for new engine alternatives $/kWh	$0.010
O&M rate for new microturbine alternatives $/kWh	$0.025
O&M rate for new fuel cell alternatives $/kWh	$0.037
O&M rate for fuel treatment system $/kWh	$0.010

Table 8 Life Cycle Cost Analysis – Current Process Configuration
Cogeneration Assessment
SLCDPU

Project Alternative	Description	Estimated Project Cost(1) ($ Million)	Total Present Worth of Costs(2,3) ($ Million)	Total PW of Net Benefit Compared to Existing Cogeneration ($ Million)
1	Existing Cogeneration – Run 1 Engine	0	8.3	-0.8
2	Existing Cogeneration – Run 2 Engines w/o NG purchase	0	7.5	-
3	Existing Cogeneration – Run 2 Engines w/ NG purchase	0	8.4	-0.9
4	New 1400 kW Engine	9.4	14.9	-7.4
5	New 1000 kW Microturbine	6.7	15.2	-7.7
6	New 1400 kW Fuel Cell	12.1	20.9	-13.4

Notes:
(1) This includes estimated construction cost plus associated costs for engineering, administration, and construction management.
(2) This includes overall treatment plant energy and O&M costs for each individual alternative.
(3) This does not include future potential regulatory surcharges based on future greenhouse gas and emission regulations.

Table 9 Life Cycle Cost Analysis – BNR Process Configuration Cogeneration Assessment SLCDPU

Project Alternative	Description	Estimated Project Cost(1) ($ Million)	Total Present Worth of Costs(2,3) ($ Million)	Total PW of Net Benefit Compared to Existing Cogeneration ($ Million)
1	Existing Cogeneration – Run 1 Engine	0	10.1	-
2	Existing Cogeneration – Run 2 Engines w/o NG purchase	N/A(4)	N/A(4)	N/A(4)
3	Existing Cogeneration – Run 2 Engines w/ NG purchase	0	12.7	-2.6
4	New 850 kW Engine	8.6	17.3	-7.2
5	New 666 kW Microturbine	5.3	15.9	-5.8
6	New 900 kW Fuel Cell	10.7	22.2	-12.1

Notes:

(1) This includes estimated construction cost plus and associated costs for engineering, administration, and construction management.
(2) This includes overall treatment plant energy and O&M costs for each individual alternative.
(3) This does not include future potential regulatory surcharges based on future greenhouse gas and emission regulations.
(4) Alternative 2 not viable as insufficient digester gas to run both existing engines without natural gas purchase

Table 10 Greenhouse Gas Emissions Cogeneration Assessment SLCDPU

Project Alternative	Current		BNR	
	GHG Emissions from Onsite Combustion(1), CO_2 Equivalent value (metric-ton/year)	Total GHG Emissions(2), CO_2 Equivalent value (metric ton/year)	GHG Emissions from Onsite Combustion(1), CO_2 Equivalent value (metric-ton/year)	Total GHG Emissions(2), CO_2 Equivalent value (metric ton/year)
Existing Cogeneration (1 Engine w/o NG)	5,200	8,700	3,800	9,000
Existing Cogeneration (2 Engines w/o NG)	5,100	7,000	N/A	N/A
Existing Cogeneration (2 Engines w/ NG)	5,800	7,100	5,900	8,500
New Engine	5,100	5,900	4,400	8,900
New Microturbines	5,100	7,800	6,000	11,400
New Fuel Cells	7,500	7,800	8,500	12,400

Notes:
(1) CO_2 equivalent emissions from CH_4, CO_2, and N_2O produced onsite from combustion of digester gas and natural gas through cogeneration or by flaring the gas.
(2) CO_2 equivalent emissions from CH_4, CO_2, and N_2O produced from onsite combustion and the emissions produced from electricity generation by Rocky Mountain Power.

Table 11 Cogeneration Study Alternatives - Rating Matrix
Cogeneration Assessment
SLCDPU

Ranking Criteria		Present Worth of Life Cycle Cost[3]	Energy/Green-house Gas Regulations	Protection Against Energy Price Volatility	Reliability/ Redundancy	O&M Complexity	Length of Permit Application Process	Proven Biogas Cogeneration Technology	Footprint	Efficient Use of Resources	Total Weighted Score[1]
Weighting Factor[2]		5	5	3	4	4	3	3	3	5	–
Project Alternative	Description										
1	Existing Cogeneration (1 w/o NG)	4	2	4	5	4	5	5	4	4	140
2	Existing Cogeneration (2 w/o NG)	4	2	4	4	4	4	5	4	3	128
3	Existing Cogeneration (2 w/ NG)	3	2	3	4	4	4	5	4	5	130
4	New Engines	2	4	4	4	5	3	4	4	3	126
5	New Microturbine	1	2	2	4	3	4	3	3	2	89
6	New Fuel Cell	1	4	3	3	2	4	2	2	3	93

Notes:
(1) Total Weighted Score equals the sum of each criteria's weighted factor multiplied by its individual ranking for each respective alternative; highest value is most desirable/beneficial, lowest value is least desirable/beneficial.
(2) Weighting Factors: 5 - More Important, 1 - Less Important.
(3) Present worth of life cycle costs are based on the worst case digester gas projection as shown in Table 8 for Current Process Configuration.

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6.0 RECOMMENDATIONS

The recommendation of this cogeneration assessment for SLCDPU is to continue to use the existing engines with either the current treatment process or a new BNR process. New equipment reduces emissions and increases efficiency but results in higher life cycle costs.

Additional recommendations include the following:

- Renegotiate the terms of the contract with the power utility to allow for export of excess power. This would allow for operation of both existing engines and reduce the quantity of flared digester gas.
- Consider a fats, oils and grease (FOG) collection program in the city and add this waste to the digesters, which currently have spare capacity. FOG collection programs in other locations have led to increase in digester gas production of 25-50 percent.
- An alternative outside the scope of this study that could be considered is using digester gas for fleet vehicles.

Note:

A complete copy of Carollo Engineers' report Appendices A-D, is included in the Phase II Technical Memorandum dated December 14, 2014.

Appendix C

Phase II Scoring and Ranking Matrix

Salt Lake City Renewable Energy Plan
Detailed Site Evaluation and Project Ranking

Category			Site						Interconnection		Zoning	Permitting	Generation				Sustainability						Weighted Average Scoring
Weight			30%						15%		15%	10%	20%				10%						
Criteria			Compatibility with existing site use	Infrastructure	Site access	Physical Characteristics	Public safety	Public Nuisance	Access	Ease of interconnection	Local Zoning Standards	Local State Federal	Resource Quality	Power Resiliency and reliability	Electricity Supply	Electricity End Use	Renewable Energy	Energy sustainability	Climate Change	Leadership and Education	Economic Development	Public Policy	
Description			Ability to integrate renewable energy project with existing DPU site use	Extent to which project can be constructed with existing infrastructure at the site.	Site access for construction and , interconnection activities	Are there obvious physical site constraints, e.g. topographical, geologic, property line encroachment, proximity to scenic, recreation or environmentally sensitive areas?	Does project location create a potential safety risk to the public?	Does proximity of the project to residences or other established uses in the vicinity pose a potential public nuisance (visual, degradation of property value, noise etc.	Extent to which project site provides either direct access to DPU load or the distribution system.	Complexity and costs of meeting distribution system interconnection requirements including costs of studies and complexity and costs of additional equipment required for interconnection	Extent to which renewable energy project is compatible with existing zoning ordinances.	Permitting Requirements and Complexity	Quality of RE resource at the site	Will the project increase DPU energy system resiliency to power outages and reliability of the delivery of DPU services?	Extent to which ptential RE project will serve load at the project site	How is the project likely to contribute to offsetting DPU's largest and most critical end use loads?	Will this project contribute to meeting SLC's renewable energy goals?	Extent this project will contribute to reducing reliance on fossil generated electricity and demonstrate efficient use of energy	Extent to which project will contribute to meeting SLC's GHG goals.	Will this project enhance opportunities to educate SLC citizens and improve public perception of DPU and the City's commitment to clean energy and air?	Potential to enhance opportunities for local clean energy vendors and jobs.	Will this project demonstrate leadership (leading by example) or remove regulatory or policy barriers that will lead to an increase in the deployment of distributed renewable energy systems in SLC	
Weight			20%	15%	15%	15%	15%	20%	50%	50%	100%	100%	25%	25%	25%	25%	20%	20%	10%	15%	15%	20%	
Project Site																							
Project No. 1	Mountain Dell Dam	Hydroelectric	2	2	2	3	5	5	5	3	5	5	5	0	5	5	5	5	5	4	3	5	4.0150
Project No. 2	Terminal Park Reservoir	Roof Mount PV	5	4	5	4	5	5	5	3	1	1	5	0	5	1	5	3	3	5	5	5	3.2500
Project No. 3	Morris Reservoir	Roof Mount PV	5	2	5	4	4	3	5	3	1	4	5	0	3	5	5	3	4	4	3	5	3.3600
Project No. 4	South Lift	Ground Mount PV	5	3	5	5	3	4	5	3	5	5	5	0	3	5	5	3	4	4	3	5	4.1650
Project No. 5	15th East Reservoir	Roof Mount PV	5	5	4	3	5	4	5	3	5	5	5	0	3	5	4	4	5	5	4	4	4.2300
Project No. 6	B35-R18	Microhydro	2	2	1	2	3	5	3	3	4	5	2	0	0	0	5	0	0	1	3	5	2.6900
Project No. 7	B11-R13	Microhydro	2	2	3	3	5	5	3	3	4	5	2	0	0	0	5	0	0	1	3	5	2.9150
Project No. 8	C41-R20	Microhydro	2	2	1	2	3	5	3	3	4	5	2	0	0	0	5	0	0	1	3	5	2.6900
Project No. 9	Victory Rd Reservoir	Roof Mount PV	5	5	2	3	5	5	5	3	1	3	5	0	2	5	5	3	4	3	3	5	3.3150
Project No. 10	Concord Lift	Ground Mount PV	5	3	2	2	2	2	5	3	0	3	1	0	3	5	5	3	4	3	2	4	2.5300
Project No. 11	Baskin Rreservoir	Roof Mount PV	4	2	5	1	5	5	2	2	1	5	5	0	3	5	5	3	4	3	4	5	3.1300
Project No. 12	Wilson Reservoir	Roof Mount PV	5	4	2	4	3	2	5	3	5	2	5	0	3	5	5	3	4	3	3	5	3.5950
Project No. 13	6200 S. Well	Ground Mount PV	5	4	4	3	3	5	5	4	3	4	1	0	1	5	5	2	3	3	2	4	3.4300
Project No. 14	D74-DV-1	Microhydro	2	1	5	3	3	5	1	1	5	5	3	0	0	0	5	0	0	1	3	5	2.7700
Project No. 15	Greenfield Village Well	Ground Mount PV	5	4	5	3	4	5	3	1	5	1	5	0	1	5	5	3	3	2	3	4	3.3650
Project No. 16	Sorenson Fitness Center	Roof Mount PV	5	4	5	5	5	5	5	4	5	5	5	0	3	3	3	3	3	4	4	4	4.2800
Project No. 17	SLC DPU Building	Roof Mount PV	5	4	5	5	5	4	5	4	5	5	5	0	4	3	3	3	3	4	4	4	4.2700
Project No. 18	SLCWRF Cogeneration	Biogas	5	5	5	5	5	5	5	5	5	5	5	0	5	5	5	3	3	4	3	5	4.6450
Project No. 19	500 South Trunlkine	Waste Heat Recovery	5	2	3	2	5	5	5	3	5	5	5	0	3	5	4	3	4	4	3	5	4.0250

Appendix D

Rate Schedule and Financing Primer
Utah Clean Energy

Utah Clean Energy

Rate Schedule and Financing Primer

Salt Lake City Renewable Energy Plan

Sophie Hayes and Kate Bowman

November 1, 2014

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Appendix A: Summary of Available Rate Structures:

Electric Service Schedule 31: Partial Requirements Service – Large General Service – 1,000 kW and Over

Schedule 31 provides supplementary, backup and maintenance power to customers who obtain any part of their regular electric requirements from self-generation. This schedule is for customers who would otherwise qualify for Schedules 8 or 9 and who have on-site generation capacity between 1,000 kW and 15,000 kW.

This rate schedule was designed such that large "partial requirements" customers compensate the utility for being ready to serve as a "backup generator" during planned or unplanned outages and for supplementary power and energy not served by onsite generation. Under this tariff, customers contract with the Company for a specified amount of both supplementary power and backup power, which the Company agrees to have available for delivery to the customer.

All energy consumed under Schedule 31 is billed based on the pricing outlined in the customer's general service schedule (Schedule 8 or 9). Power charges are determined based on the amount of supplementary power and backup power contracted for. Supplementary power is billed based on the power charges specified in the customer's general service schedule. The power charge for backup power is based on the 15-minute period of highest on-peak usage. Backup power charges are reduced by half during scheduled maintenance, and there is no charge for off-peak backup power. Backup power is subject to a facilities charge, based on voltage. Any power above and beyond the total contracted power is considered Excess Power. Customers on this rate schedule also pay a monthly customer charge.

Although this rate schedule could be used to supply supplementary and backup power to a facility with on-site generation from renewables, it would only be practical if the customer's generation were to track usage closely (or if usage could be scheduled to track generation). Schedule 31 anticipates that customers will be reducing or eliminating their usage of Company power the majority of the time and does not provide credits for electricity production in excess of usage, nor does it allow for resale of excess electricity; however, a facility taking service under Schedule 31 may still qualify as a "Qualifying Facility" (see below) and sell excess electricity back to the utility at wholesale "avoided costs" rates.

Full text of Schedule 31:
https://www.rockymountainpower.net/content/dam/rocky_mountain_power/doc/About_Us/Rates_and_Regulation/Utah/Approved_Tariffs/Rate_Schedules/Partial_Requirements_Service_Large_General_Service_1_000_kW_and_Over.pdf

Electric Service Schedule 32: Service from Renewable Energy Facilities

Schedule 32 was enabled by Senate Bill 12 (SB12), passed during the 2012 legislative session, but has not yet been finalized or approved by the Public Service Commission. This tariff is designed to serve large customers who would like to source a larger portion of their electric service from renewable energy resources than is currently available through the Company's resource portfolio. Using Schedule 32, large customers will be able to build or purchase energy from off-site renewable energy projects and pay Rocky Mountain Power for the delivery of such electricity to their facilities. Whether the renewable facility is owned by the customer or a third party, the customer and the renewable energy facility pay all of the costs and bear all of the risk of the renewable energy facility, and the facility is also responsible for all interconnection and integration costs. The customer must contract for more than 2. 0 MW of electricity delivery through Schedule 32.

As between a renewable energy facility and a Schedule 32 customer, electricity delivery is facilitated by two matching contracts: the Rocky Mountain Power will contract with the owner of the renewable energy facility to purchase electricity for resale to the customer (or in some cases more than one customer). Rocky Mountain Power will then sell that electricity to the customer or customers under renewable energy contracts with the same duration and pricing as the contract between the company and the owner of the renewable energy facility. Customers who want to develop their own renewable energy facilities may also contract for the delivery of electricity from their own off-site renewable projects through this tariff. Schedule 32 does not replicate virtual net metering and does not allow net metering.

This tariff is not yet finalized, however Utah Clean Energy will be able to provide additional recommendations regarding the utility of this tariff when it is finalized.

Full text of Senate Bill 12: http://le.utah.gov/~2012/htmdoc/sbillhtm/SB0012S01.htm

PURPA & Qualifying Facilities

The Public Utilities Regulatory Policy Act (PURPA) was passed in 1978 to promote greater use of domestic energy and renewable energy. PURPA established the “Qualifying Facility” (QF) class of electricity generating facilities to receive special rate and regulatory treatment, in the interest of promoting their development. QFs fall into two categories:

- Small Power Production Facilities, which are facilities of 80 MW or less whose primary energy source is renewable, including solar, hydro, wind, geothermal, or biomass resources.

- Cogeneration Facilities, which sequentially produce electricity and thermal energy (such as steam or heat) in a way that is more efficient than producing each independently.

One provision of PURPA requires that monopoly utilities purchase power from Qualifying Facilities that are able to provide electricity at rates equivalent to the utility's own "avoided cost." Avoided cost is defined as the incremental cost to an electric utility of electric energy or capacity, which, but for the purchase from the QF, the utility would have to generate itself or purchase from another source.

An owner or operator of a generating facility with a maximum net power production capacity of greater than 1 MW (1,000 kW) may obtain QF status by submitting a "self-certification" (no fee) or by applying for and obtaining Federal Energy Regulatory Commission (FERC) certification of QF status (fee required). To obtain QF status, facilities must file an electronic form through the FERC website. Facilities smaller than 1 MW do not need to certify in order to qualify as QFs.

Pursuant to PURPA, FERC adopted regulations relating to purchases and sales of electricity to and from QFs. These regulations afford state utility commissions wide latitude in setting avoided cost prices and procedures for purchases from QFs. In Utah, the Public Service Commission has approved two electric service schedules (Schedules 37 and 38) for implementing PURPA and FERC regulations.

Electric Service Schedule 37: Avoided Cost Purchases from Qualifying Facilities

Schedule 37 is available to owners of small QFs: either cogeneration facilities with a design capacity of one MW or less or Small Power Production Facilities with capacity of three MW or less. Avoided cost rates under Schedule 37 are published, "standard offer" rates. QFs enter into a written power sales contract with Rocky Mountain Power based on these published prices.

There is a cumulative cap of 25 MW of capacity for new resources contracted under this schedule before Rocky Mountain Power must update Schedule 37 rates. However, the Commission requires that Rocky Mountain Power update Schedule 37 rates once a year, so the 25 MW cap is effectively an annual cap.

Schedule 37 rates are published as non-levelized annual rates (winter on- and off-peak and summer on- and off-peak rates) or as 20 –year nominal (present value) levelized prices in cents per kWh. Current levelized prices for baseload and solar facilities are the following:

Levelized Prices (Nominal) for baseload (cogeneration) resources in cents per kWh:

On-Peak Energy Prices		Off-Peak Energy Prices	
Winter	Summer	Winter	Summer
4.589	4.819	3.859	4.089

Levelized Prices (Nominal) for fixed tilt solar resources in cents per kWh:

On-Peak Energy Prices		Off-Peak Energy Prices	
Winter	Summer	Winter	Summer
4.013	4.246	3.548	3.781

Levelized Prices (Nominal) for tracking solar resources in cents per kWh:

On-Peak Energy Prices		Off-Peak Energy Prices	
Winter	Summer	Winter	Summer
4.188	4.420	3.613	3.846

Full Text of Schedule 37: https://www.rockymountainpower.net/content/dam/rocky_mountain_power/doc/About_Us/Rates_and_Regulation/Utah/Approved_Tariffs/Rate_Schedules/Avoided_Cost_Purchases_from_Qualifying_Facilities.pdf

Electric Service Schedule 38: Qualifying Facility Procedures

Schedule 38 is available to owners of cogeneration QFs with capacity greater than one MW or renewable QFs with capacity greater than three MW, and can be used to make electricity sales to Rocky Mountain Power. Pricing under this schedule is not published; rather the Commission approved a pricing calculation method that Rocky Mountain Power uses to establish “indicative prices.” Large QFs negotiate pricing and contract terms directly with Rocky Mountain Power based on the supply characteristics of the QF and the utility resources it will displace.

Full text of Schedule 38:
https://www.rockymountainpower.net/content/dam/rocky_mountain_power/doc/About_Us/Rates_and_Regulation/Utah/Approved_Tariffs/Rate_Schedules/Qualifying_Facility_Procedures.pdf

Schedule 135: Net Metering

Net metering allows customers with on-site renewable energy facilities to connect to the electrical grid and receive credit for excess electricity that is produced, but not consumed, on-site. A “net meter” replaces the standard electrical meter and measures both the electricity supplied by the Company and the electricity which is generated by the customer and fed back to the electric grid. Electricity produced by the generating facility is first consumed onsite, but if the customer is not consuming electricity at the time it is being generated, excess electricity is sent back out to the electrical grid. The customer is billed for their ‘net usage’ over the course of a monthly billing period: the electricity supplied by the utility, minus the electricity supplied by the customer. Facilities which are eligible for net metering must use energy derived from one of the following to generate electricity:

- solar photovoltaic and solar thermal energy
- wind energy
- hydrogen
- organic waste
- hydroelectric energy
- waste gas and waste heat capture or recovery
- biomass and biomass byproducts, except for the combustion of
    - wood that has been treated with chemical preservatives such as creosote, pentachlorophenol, or chromated copper arsenate
    - municipal waste in a solid form
- forest or rangeland woody debris from harvesting or thinning conducted to improve forest or rangeland ecological health and to reduce wildfire risk
- agricultural residues
- dedicated energy crops
- landfill gas or biogas produced from organic matter, wastewater, anaerobic digesters, or municipal solid waste
- geothermal energy

Schedule 135 requires that generating facilities be located on or adjacent to the customer’s premises, and are intended primarily to offset part or all of the customer’s own electrical requirements. The customer-generator can aggregate its electrical requirements from multiple meters for the purpose of net metering, as long as all meters are located at or adjacent to the same property. Non-residential facilities can be up to 2 MW, although Schedule 135 is structured to encourage generating facilities to be sized such that average annual generation does not exceed average annual onsite load. Compensation for excess electricity production depends on whether a facility is considered a “small non-residential customer” or “large non-residential customer:”

- Small non-residential customers (who are otherwise billed under Schedule 15 or Schedule 23) are credited for excess electricity production with a cumulative kilowatt-hour credit. The credit will be deducted from the customer's kilowatt-hour usage on their next monthly bill, offsetting the customer's next monthly bill at the full retail rate of the customer's rate schedule. These credits roll over month-to-month until the customer's March billing period, after which remaining credits expire.
- Large non-residential customers (who are otherwise billed under Schedule 6, 6A, 6B, Schedule 8, or Schedule 10) are billed for their net electricity usage each month. In the event that generation exceeds usage in a given month, these customers can choose to receive credit for this excess electricity production one of three ways:

(1) Receive an average energy price per kilowatt-hour based on volumetric non-levelized energy prices in Schedule 37, using the following formula:

  0.38 x Winter On-Peak Energy Price
+ 0.19 x Summer On-Peak Energy Price
+ 0.29 x Winter Off-Peak Energy Price
<u>+ 0.14 x Summer Off-Peak Energy Price</u>
= total compensation for excess electricity production

(2) Receive a seasonally differentiated energy price based on non-levelized energy prices in Schedule 37, using the following formula:

Summer months (June – September):

  0.57 x Summer On-Peak Energy Price
<u>+ 0.43 x Summer Off-Peak Energy Price</u>
= compensation for excess electricity production from Jun – Sep

Winter months (October – May):

  0.57 x Winter On-Peak Energy Price
<u>+ 0.43 x Winter Off-Peak Energy Price</u>
= compensation for excess electricity production from Oct - May

(3) An average retail rate for the Electric Service Schedule applicable to the net metering customer as calculated from the previous year's Federal Energy Regulation Commission Form No. 1. Average retail rates from the most recently filed tariff (. effective September 2014) are the following:

Schedule 6: 8.2075¢ per kWh
Schedule 6A: 11.2772¢ per kWh
Schedule 6B: 8.5765¢ per kWh
Schedule 8: 7.2585¢ per kWh
Schedule 10: 7.1794¢ per kWh

The Utah Legislature originally required that electrical corporations offer net metering to their customers in 2002, through House Bill 0007. Utah's net metering law has since been modified several times, most recently during the 2014 legislative session through Senate Bill 208. Recent modifications to net metering legislation, in Utah and across the United States, have focused on the potential that net metering rate schedules do not adequately account for the costs and benefits of net metering customers and allow for cross-subsidization amongst ratepayers. Senate Bill 208 (2014) directed the Utah Public Service Commission (PSC) to determine whether costs incurred from a net metering program will exceed the benefits of the net metering program or vice versa, and to determine a just and reasonable charge, credit or ratemaking structure in light of the costs and benefits.

Rocky Mountain Power's net metering program is currently available to any customer who owns or leases a renewable generating facility, and capacity for the program is capped at 20% of the Company's 2007 peak demand. According to Rocky Mountain Power's 2014 Net Metering Customer Generation Report, only two percent of this capacity has been filled. Changes to the net metering tariff and Schedule 135 may have an impact on its value to self-generation customers in the future; however in its current form, Schedule 135 is the recommended tariff for customers with renewable generation who meet the net metering qualifications.

Full text of Schedule 135:
https://www.rockymountainpower.net/content/dam/rocky_mountain_power/doc/About_Us/Rates_and_Regulation/Utah/Approved_Tariffs/Rate_Schedules/Net_Metering_Service.pdf

Virtual Net Metering:

Virtual net metering allows parties to receive credit or compensation for generation from offsite renewable energy facilities. Similarly, a structure often known as "community net metering" can allow multiple parties to purchase shares of the output from a single renewable facility that is not physically connected to their property (or their meter). Virtual net metering and community net meting models allow individuals who are not good candidates for distributed solar (due to shading, or because they are renting their home or live in an apartment) to source electricity from renewable generation. Virtual net metering is not

currently authorized in Utah statute, and enabling a virtual net metering policy which allows kilowatt-hour per kilowatt-hour credits from an offsite solar facility to offset a customer's energy bill would require legislative action. Sixteen states and the District of Columbia have authorized some form of virtual net metering, although policies vary widely from state to state. Some variations simply authorize virtual net metering as an option that utilities may choose (but are not required) to offer, or restrict the policy to certain entities, certain utility service areas, or certain geographic areas. [1]

Utah's existing net metering statute has been the subject of heated debate in the last few months; recent modifications to net metering legislation, in Utah and across the United States, have focused on the potential that net metering rate schedules do not adequately account for the costs and benefits of net metering customers and thus allow for cross-subsidization amongst ratepayers. The Public Service Commission has launched a new docket, *14-035-114,* to investigate the costs and benefits of residential net metering, specifically. No previous docket has thoroughly investigated both the costs *and* the benefits of net metering, and the findings of Docket 14-035-114 will have an impact on the future of virtual net metering in Utah.

A few case studies of virtual net metering programs in other states provide examples of potential uses here in Utah:

Clean Energy Collective:

Clean Energy Collective (CEC) is a private company that funds, builds, and maintains medium-scale clean power facilities that are collectively owned by participating utility customers. Often referred to as "community solar" arrays, CEC projects can range from 500 kW to 50 MW in size and are sited in an ideal location and interconnected to the local utility's grid. CEC has 33 existing or ongoing projects, in 6 states (CO, MA, MN, NM, VT, WI) and 13 utility service territories. Although many of the utilities participating in CEC-built solar arrays are municipal or customer-owned co-operative utilities, several large investor-owned utilities have worked with CEC to develop solar projects, including National Grid (3 projects of 1 MW each in Massachusetts), NSTAR (2 projects of 1 MW each in Massachusetts), the Western

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[1]For a more in depth discussion of the types virtual net metering policies by state, see the following reports: National Conference of State Legislatures, "Net Metering: Policy Overview and State Legislative Updates." <http://www.ncsl.org/research/energy/net-metering-policy-overview-and-state-legislative-updates.aspx>.
Institute for Local Self-Reliance, "Virtual Net Metering." <http://www.ilsr.org/virtual-net-metering/>.
ICLEI, "Aggregate Net Metering: Opportunities for Local Governments." <http://www.icleiusa.org/action-center/aggregate-net-metering-opportunities-for-local-governments>.

Massachusetts Electric Company (2 projects of 1 MW each in Massachusetts), and Xcel Energy (11 projects totaling just over 5 MW in Colorado).

Participating customers can purchase one or more panels in the array and receive compensation for the electricity produced by their solar panels. CEC claims to have superseded the constraints of net metering laws through partnerships with utilities and by using billing software that doesn't require legislation to distribute on-bill credits to customers. Instead, the electricity generated from the panels is sold directly to the utility through a mutually agreed contract (such as a Power Purchase Agreement or a Feed-in Tariff). The customer receives a portion of the monetary payment for the electricity, based on the panels they have purchased, via an on-bill credit. CEC uses a proprietary RemoteMeter™ system to calculate monthly bill credits for members in a way that integrates with utilities' existing billing system.

Connecticut and Virtual Net Metering

Connecticut has made virtual net metering available exclusively to state, municipal, and agricultural customers, who may host virtual net metering facilities and credit the generation towards their own accounts as well as other authorized accounts[2]. A virtual net metering facility can be up to 3 MW and must generate electricity using either renewable resources or combined heat and power. The virtual net metering facility can be owned by the host (a state, municipal, or agricultural customer), leased by the host, or owned by a third party and located on the host's property.

Virtual net metering hosts may aggregate all of the meters they own and receive credits towards their own accounts for electricity generated at the facility, and may also credit the electricity generated by the facility towards 'beneficial accounts' as long as they are within the same distribution company's service territory. A municipal or state customer can host up to 5 additional municipal or state accounts and 5 additional non-state or -municipal buildings if those accounts are critical facilities (including hospitals, police stations, fire stations, water treatment plants, sewage treatment plants, and public shelters) and connected to a micro grid. An agricultural customer can host up to 10 beneficial accounts as long as those accounts either use electricity for agricultural purposes, or are municipal or noncommercial critical facilities. When host customers produce more electricity than they consume, the excess electricity is credited to these beneficial accounts.

[2] More information from DSIRE: http://dsireusa.org/incentives/incentive.cfm?Incentive_Code=CT01R&re=0&ee=0.

Appendix B: Summary of Available Financing Options:

Utah Solar Incentive Program

The Utah Solar Incentive Program provides Rocky Mountain Power customers with a rebate for a portion of the initial cost of installing a solar photovoltaic system. Rocky Mountain Power administers the program, and Rocky Mountain Power customers can apply for the incentive during a two week period in January each year. Incentives are awarded based on a lottery system. The incentive rates and availability differ based on system size and customer class, and incentives decrease each year of the 5-year program. There is a cap on the incentive amount that is available for each category of project each year. For 2015, the available incentives and

Category		Small Non-Residential	Large Non-Residential
System Size*		≤ 25 kW*	> 25 kW ≤ 1,000 kW*
2015	Available Capacity	4,000 kW (AC)	8,500 kW (AC)
	Available Incentive	\$0.90/Watt (AC)	\$0.70/Watt (AC)
2016	Available Capacity	4,500 kW (AC)	10,000 kW (AC)
	Available Incentive	\$0.85/Watt (AC)	\$0.65/Watt (AC)

capacity are as follows:

*This does not refer to the maximum allowable size for the photovoltaic installation, but to the maximum amount of capacity which the incentive can be applied to. For example, although commercial installations may be up to 2MW, based on the net metering requirements, only half of a 2 MW system would be eligible to receive the incentive.

Recipients of the incentive must enroll in Rocky Mountain Power's Cool Keeper program, which allows Rocky Mountain Power to coordinate individual air conditioning units, reducing peak energy demand in the summer. Recipients of the incentive must also sign a portion of the Renewable Energy Certificates (RECs)[3] generated by the system over to Rocky Mountain Power, equal to 0.28 MW for each incentivized kW per year for 20 years. This amounts to approximately 20% of the RECs generated by a solar installation, and relinquishing ownership of the RECs may limit the rights to publically advertise an installation as a green power facility. This provision should also be considered carefully for any facility that will be pursuing LEED certifications or other green building certifications. The owner of the solar installation could choose to register the remaining RECs with a certified REC tracking organization (such as WREGIS) in order to sell them through REC broker. In order to prevent 'double-counting' RECS,

[3] The E.P.A. defines RECs as "The property rights to the environmental, social, and other nonpower qualities of renewable electricity generation." < http://www.epa.gov/greenpower/gpmarket/rec.htm>.

any given facility can only be registered once, so the owner of the installation would have to coordinate registration of their facility and divide ownership of the RECs in coordination with Rocky Mountain Power.

While applications for the Utah Solar Incentive Program can be very competitive, particularly within the residential category, the small non-residential category has been under-utilized in past years and presents an opportunity for smaller solar PV installations of less than 25 kW. In 2013, all of the small non-residential projects that applied for the incentive were offered capacity, and the total of these applications still did not reach the cap for the program in 2013. Rocky Mountain Power re-opened the application process in May to accept additional applications for this category. Approximately 1 MW of capacity was not ultimately used, and this capacity carried forward to be used in the future. Once again, in 2014, every small non-residential applicant was offered capacity. The Utah Solar Incentive Program is currently scheduled to run through 2017, and cannot be combined with any other Rocky Mountain Power incentive or grant programs, including Blue Sky Community Grants.

For more information and to apply: https://www.rockymountainpower.net/env/nmcg/usip.html

Blue Sky Community Grants

Rocky Mountain Power's Blue Sky program allows electric customers to choose to pay an additional fee on their bill to support renewable energy. A portion of these fees is used to provide grants for the construction of renewable energy installations (including solar PV, wind, geothermal, hydro, wave energy, and low-emissions biomass) through the Blue Sky Community Project Funds. Rocky Mountain Power accepts applications for Blue Sky Community grants on an annual basis, and any locally-owned, commercial-scale project of 10 MW or less may apply. Funding from the Blue Sky program is awarded considering the "reasonableness of the budget and funding request, the technology, project location, the complexity of the installation, community benefits, potential for public education, project readiness and the ability of the project sponsor to leverage other funding sources." Smaller projects (typically considered to be projects less than 25 kW) must be net metered, and larger projects may make other interconnection agreements with Rocky Mountain Power (although off-grid projects are not eligible.) Applicants may only receive funding through the Blue Sky program once every 3 years, and Blue Sky grants can only fund up to 60% of the total project costs. Although the majority of Blue Sky Community Grant awards have gone to solar projects, a few wind, low-impact hydro, and biomass projects have also received funding through this program.

The application window for 2015 has not been announced, but in 2014 Rocky Mountain Power accepted applications from April 9 to June 30, planned to announce awards by November 30 2014, and required that all projects be completed by December 2015. Blue Sky grants have funded numerous projects in Salt Lake City, including solar installations on churches; educational, arts, or cultural centers; Utah Transit Authority facilities; Salt Lake City School District buildings; and Salt Lake City's Plaza 349 building.

For more information and to apply: https://www.rockymountainpower.net/blueskyfunds

Power Purchase Agreements (PPAs)

A Power Purchase Agreement is a contract between two parties which outlines terms for the sale of electricity from one party to another. Power Purchase Agreements are commonly used as a financing mechanism for solar photovoltaic installations. Typically, a third-party developer builds, owns, and maintains a solar photovoltaic system for a host customer, and the host customer agrees to purchase electricity produced by the solar panels at a fixed price for a predetermined time period. The solar installation may be located on the host customer's roof or property, and many PPAs give the host customer the opportunity to purchase the solar equipment at depreciated rates after a certain time period. PPAs are an advantageous financial arrangement for non-profit organizations, local governments, and other entities who cannot take advantage of tax incentives because they allow the third-party developer to receive the tax benefits of the solar installation and pass the savings on to their host customer.

In 2010, House Bill 145 authorized Power Purchase Agreements for certain entities by clarifying that independent energy producers may sell electricity to non-profits, local governments, and schools without being considered a public utility and subjected to the regulation required of a public utility.

Full statute available at: http://le.utah.gov/code/TITLE54/htm/54_02_000100.htm

CPACE

Commercial Property Assessed Clean Energy (C- PACE) financing is an innovative way to finance energy efficiency, renewable energy, and water conservation upgrades to commercial buildings. Interested property owners select measures that achieve energy or water savings and receive 100% financing for their project, repaid as a property tax assessment for up to 20 years.

This assessment mechanism has been used nationwide for decades to access low-cost, long-term capital to finance improvements to property that meet a public purpose. During the 2013 Legislative Session, Senate Bill 221 authorized public agencies to issue bonds specifically for the purpose of a renewable energy or energy efficiency upgrades.

C-PACE financing is only available to private property owners, however it could potentially be used to finance clean energy or energy efficiency upgrades on a privately-owned facility in which the Department of Public Utilities rents space. Utah Clean Energy has assembled an Advisory Committee comprised of local governments, financial experts, attorneys, contractors, and businesses to identify best practices and implement pilot projects in 2015. Several local jurisdictions, including Salt Lake City, are currently coordinating to make C-PACE financing available to businesses in their jurisdiction.

Qualified Energy Conservation Bonds

Qualified Energy Conservation Bonds, or QECBs, are a debt instrument that enables qualified states, territories, and local governments to issue tax credit bonds with very low effective interest rates in order to fund energy conservation or renewable energy projects. QECB bonds were authorized by the Energy Improvement and Extension Act of 2008, and the American Recovery and Reinvestment Act (ARRA) of 2009 increased the volume cap for QECBs issued from $800 million to $3.2 billion. This total allocation has been divided amongst the States proportionally based on population, and further allocated to any “large local government” with a population greater than 100,000. Salt Lake City was allocated $1,908,605 and has not yet taken advantage of this allocation. Salt Lake County was allocated $6,392,683 and has used a portion of this allocation. A portion of the overall allocation was reserved to be held by the State of Utah, and $4,306,920 of this allocation remains. QECBs are intended to be used by public entities, however up to 30% of the allocation may be awarded to private entities.

Federal subsidies available for QECBs make them an extremely low-cost financing option. Issuers of QECBs can choose either to issue taxable bonds with a corresponding non-refundable tax credit to the holders of the bonds, or elect to receive a direct cash payment from the Department of Treasury that is equivalent to the amount of the non-refundable tax credit. Of these two options, the direct-pay QECB option is more popular. Both options create a lower effective interest rate for the borrower through Federal subsidies.

Individual jurisdictions may be able to pool their allocations in order to offer larger bonds and minimize the transaction cost of bond issuance per dollar financed. Individual jurisdictions can waive their sub-allocations, in which case they return to the state and can be made available to any entities in the state. Although there are no documented cases of local jurisdictions pooling their sub-allocations without state involvement, there are examples where local jurisdictions have pooled other tax-credit bonds. [4]

QECBs may be issued for "qualified conservation purposes" as defined in section 54D of the U. S. Internal Revenue Code (I. R. C. §54D), including capital expenditures:

- To reduce energy consumption in publicly owned buildings by at least 20%.
- To implement green community programs (including the use of grants, loans, or other repayment mechanisms to implement such programs).
- For rural development (including the production of renewable energy).
- For certain renewable energy facilities (such as wind, solar, and biomass).
- For certain mass commuting projects.

Cities and counties that have received allocations may create their own processes for approving projects within their jurisdictions, and the Governor's Office of Economic Development is charged with distributing Utah's allocation. Individual project developers must work either with their local jurisdiction or with the Governor's Office of Economic Development to arrange for the bond issuance. Applications for QECB from the state of Utah's allocation are available from the Governor's Office of Economic Development, and applications are accepted on a quarterly basis and then reviewed by the Private Activity Bond Authority Board at a subsequent Board Meeting. Upcoming application deadlines and board meeting dates are as follows:

Application Deadline Date	Meeting Date
November 24, 2014	January 14
February 23	April 8
May 26	July 8
August 24	October 14
October 26	December 9

For more information and to apply: http://business.utah.gov/programs/pab/energy-conservation-bonds/

[4] http://www. naseo. org/Data/Sites/1/documents/committees/financing/documents/qecb_memo_june13. pdf.

New Market Tax Credits:

The New Markets Tax Credit Program (NMTC Program) was established by Congress in 2000 to encourage investment in businesses and real estate projects located in low-income communities. The NMTC Program allows individual and corporate investors to receive a tax credit against their Federal income tax return in exchange for investing in low-income communities through Community Development Entities (CDEs), organizations with the primary mission of providing investment capital for low-income communities. The Community Development Financial Institutions (CDFI) Fund allocates tax credit authority to local CDEs through a competitive application process. CDEs can then offer tax credits to investors in exchange for equity in the CDE. This allows CDEs to make more flexible investments in distressed areas, at better interest rates than market rates. Investors receive a tax credit of 39 percent of their original investment, claimed over a period of seven years, in addition to the return on their investment in the CDE.

New Market Tax Credits can be used to fund renewable energy projects, although the structure of the project would be quite complicated. In order to take advantage of the tax incentives, a third-party developer could build, own, and maintain a solar photovoltaic system for a public entity. The Department of Public Utilities could then contract to purchase power from the privately owned facility through a Power Purchase Agreement.

Projects which emphasize a strong permanent job creation component are the most competitive and most likely to attract investor and CDE interest. Entities that are interested in utilizing New Market Tax Credits must work closely with a CDE and with potential investors to complete an application. Using New Market Tax Credits is administratively complicated and it may not be worthwhile to pursue New Market Tax Credits for projects costing less than $6-7 million. New Market Tax Credits should be considered for a larger project with good potential to create job growth. New Market Tax Credits could also be used to finance clean energy or energy efficiency upgrades on a privately-owned facility in which the Department of Public Utilities rents space.

New Market Tax Credit allocations can be awarded for renewable energy projects if they are located in census tracts which meet the following criteria designating them as 'low income' areas:

- The poverty rate is at least 20%
- Outside of a metropolitan area, the Median Family Income (MFI) does not exceed 80% of the statewide MFI
- In a metropolitan area, the Median Family Income (MFI) does not exceed 80% of the statewide MFI or the metropolitan area MFI (whichever is greater)

The following sites are located in census tracts which are considered low-income; the last three sites are not discussed in detail in this report, but are eligible for the NMTC program based on their location:

Site	Address
B11-R13	Approximately 1000 E 500 S, Salt Lake City
15th East Reservoir	Approximately 500 S and 1500 East, Salt Lake City
Salt Lake Water Reclamation Facility	1365 West 2300 North, Salt Lake City
500 South Sewer Line	Approximately 500 S and 200 E, Salt Lake City
Salt Lake City Sports Complex	645 S Guardsman Way, Salt Lake City
Sorenson Multicultural and Fitness Center	855 West California Avenue, Salt Lake City
Concord Lift Station	Approximately 1200 West California Avenue, Salt Lake City

For more information: http://www.cdfifund.gov/what_we_do/programs_id.asp?programID=5

Or contact:

Amy Rowland
Field Director
National Development Council
423 W 800 S
Ste. A-313
Salt Lake City, UT 84101
801-557-1537
arowland@nationaldevelopmentcouncil.org

USave Energy Fund:

The Utah U-Save Energy Fund program finances energy related cost reduction retrofits on existing equipment and installations for publically owned buildings by offering loans with low interest rates. A revolving loan mechanism allows borrowers to repay the loans using cost savings realized from the retrofits.

Projects which can be financed through U-Save include (but are not limited to):

- Energy efficient lighting systems
- High efficiency heating, ventilation and air conditioning systems
- Energy management systems
- Energy recovery systems
- Building shell improvements
- Load management projects
- Systems commissioning

Entities considering use of the U-Save Energy Fund are encouraged to evaluate renewable energy technologies, including rooftop solar water and space heating installations, solar photovoltaic, and small wind installations. Hydropower projects can also be eligible for U-Save Energy Fund loans. Projects financed by U-Save must have an average simple payback of five years or less, although borrowers may buy down paybacks to meet this five year limit. Loan repayments begin within sixty days of project completion and are due quarterly. The amount of annual loan repayment is based on the energy cost savings expected to result from the project (but does not change if projected savings differ from actual savings).

Applications for projects are accepted every 1 -2 years, based on the progress of the revolving loan fund. A new notice of loan funding availability will be issued in November, and applications will be accepted beginning in January. Entities who wish to apply for U-Save funds should begin by contacting the Office of Energy Development (OED), and will be asked to sign a Memorandum of Understanding agreeing to submit an Energy Assessment Report (EAR) outlining the proposed project within four months. The Office of Energy Development will reserve funding for the project during this time. When the EAR is complete, the entity applying for funding must submit the EAR along with a Loan Application, and the OED will review the application and approve it for funding. At this point, a Loan Agreement is issued guaranteeing funding for the Energy Conservation Measures outlined in the approved EAR, and the project can be started.

There are specific requirements and milestones projects must meet during the implementation process, including competitive selection of a design engineer and contractors or bidders. Applicants are expected to work closely with OED throughout the design and implementation of the project.

More Information: http://energy.utah.gov/funding-incentives/energy-financing/

Contact:

Teresa Pinkal
Energy Program Specialist
Utah Office of Energy Development
60 E. South Temple, Suite 300
Salt Lake City, UT 84111
801.538.8662

Questar ThermWise Business Custom Rebate Program

The Questar ThermWise Business Custom Rebate Program offers rebates to qualifying customers who complete natural gas saving energy efficiency projects that aren't covered by other existing Questar incentive programs. In order to qualify, the facility implementing the project must be on Questar's commercial General Service rate and must contact Questar Gas prior to purchasing or installing any equipment.

Appendix C: Franchise Agreement

The utility must have a current franchise agreement in order to receive certificates of public convenience and necessity, which are necessary for the utility's infrastructure projects. The city's franchise agreement is up for renewal in 2015 and provides an opportunity for the city to work with the utility on realizing some of its energy goals. Salt Lake City's 2015 Sustainability Plan identifies increasing renewable energy generation and market share as a key goal in the energy realm. This goal can best be achieved if the City is able to complete renewable energy installations in the most advantageous locations, where technical potential and interconnection possibilities with existing infrastructure are high.

Several of the projects described in this memo provide great opportunities for the generation of renewable electricity, and as large energy users the Department of Public Utilities and Salt Lake City both stand to gain (economically as well as in terms of environmental impact) from new sources of renewable energy. A renewed franchise agreement could create a framework though which Salt Lake City can maximize utilization of existing renewable energy sites by working with Rocky Mountain Power to coordinate the construction of new renewable energy resources with optimal locations and mutually advantageous benefits.

When choosing locations for new renewable energy projects, existing rate structures incentivize the DPU to site projects at specific facilities where energy usage is high. The facilities and properties where energy usage is high are not always ideal locations for renewable energy installations, due to space constraints, aging infrastructure, or shading. Were the Department of Utilities able to receive credits towards its general energy usage for the electricity from renewable electricity facilities located throughout its service territory, the DPU and Salt Lake City would have an additional incentive to build larger renewable projects, sited to maximize technical potential. These investments bring new resources to the grid offering all of the benefits associated with clean energy to all Rocky Mountain Power customers, including pollution-free, price-stable sources of electricity, optimally located to maximize energy production and minimize line losses.

Appendix E

Economic Cash Flow Model and Results
Energy Strategies

MEMORANDUM

TO: JEFF NIERMEYER, EXECUTIVE DIRECTOR
DEPARTMENT OF PUBLIC UTILITIES

DATE: DECEMBER 1, 2014

FROM : NICK TRAVIS, ENERGY STRATEGIES
DON HENDRICKSON

RE: SALT LAKE CITY RENEWABLE ENERGY Economic, Financial and Decision Analysis

Introduction

DPU and the Consulting Team identified project opportunities at 5 sites for economic evaluation. This section describes the approach, assumptions and results of the economic analysis. A single power generation technology was evaluated for each of four sites: 15th East Reservoir, B11-R13, Mountain Dell Dam, and Terminal Park Reservoir. Four power generation technologies were evaluated for the fifth site, the Salt Lake City Water Reclamation Facility (SLCWRF). One of the power generation options is to continue to use the existing reciprocating engine generators, the other three are: new reciprocating engines, micro turbines and fuel cells. Each of the four power generation technologies considered at the water reclamation plant was evaluated under two wastewater treatment process scenarios: 1) current process (primary clarification, trickling filters, aeration basins, secondary clarifiers and solids digestion) and 2) biological nutrient removal process. Except for at the B11-R13 and Terminal Park Reservoir sites, it was assumed that all generation could be used to offset site purchases from Rocky Mountain Power.

Economic Analysis

The economic analysis is performed using an annual cash flow model developed in Microsoft Excel. The model includes information on a "Business as Usual" or "BAU" electricity supply scenario, i.e. full requirements from Rocky Mountain Power (RMP) at all sites except partial requirements from RMP for SLCWRF which is assumed to operate one of its two existing engines with no natural gas supplementation. It also includes information on both running two existing engines at a time without and with supplemental natural gas and on each of the options to implement new power generation facilities at each site. The model provides an "incremental analysis", i.e. is used to compare the cash flows and greenhouse gas emissions associated with a comparative scenario to those with an alternative option over the economic life of the option. Refer to **Table 5-1** for a "Strategy Table" identifying key attributes of the options that were modeled.

The engineering firm conducting the study of each option was asked to provide the following information on each option:

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- In service date (constrained to be the first day of a fiscal year)
- "Overnite" capital cost in 2014$
- Percent of overnite capital cost expended in each fiscal year preceding the in service date
- Electric energy (kWh) produced by season and time period as defined under RMP rate schedules:
  - Winter and Summer
  - On-Peak Hours and Off-Peak Hours[1]
- Incremental non-fuel operating expenses.

Table 5-1. Options Considered in Economic Analysis

STRATEGY TABLE								
		Description						
Scenario/ Project Alternative	Who Conducted Study	Project Site	Site Type	Type of Wastewater Treatment Process	Type of Power Technology	Effective Generation Capacity kW	Economic Life (Years)	Use of Generation
BAU	NA	All Sites	General	Current	Existing Recip (Run 1)	1,320	20	Offset Grid Purchases
1	Sunrise	15th East Reservoir	Water Storage Reservoir	NA	Solar PV	274	30	
3	Sunrise	B11-R13	PRV in Transmission		Hydroelectric	190	50	Sell to Grid
4	Sunrise	Mountain Dell Dam	Surface Water		Hydroelectric	260	50	Offset Grid Purchases
5	Sunrise	Terminal Park Reservoir	Water Storage Reservoir		Solar PV	3,488	30	Sell to Grid
1_WRF	Carollo	SLC Water Reclamation Facility (WRF)	Wastewater	Current	Existing Recip (Run 1)	1,320	20	Offset Grid Purchases
2_WRF	Carollo				Existing Recip (Run 2 No NG)	1,320		
3_WRF	Carollo				Existing Recip (Run 2 with NG)	1,320		
4_WRF	Carollo				New Recip	1,390		
5_WRF	Carollo				Microturbine	844		
6_WRF	Carollo				Fuel Cell	1,330		
1_WRF_BNR	Carollo			Biological Nutrient Removal	Existing Recip (Run 1)	1,320	20	
3_WRF_BNR	Carollo				Existing Recip (Run 2 with NG)	1,320		
4_WRF_BNR	Carollo				New Recip	827		
5_WRF_BNR	Carollo				Microturbine	562		
6_WRF_BNR	Carollo				Fuel Cell	855		

[1] Carollo Engineers, Inc. provided estimates of annual generation which were allocated among seasons and hourly periods pro rata to the hours in each season/period.

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Refer to **Table 5-2** for a summary of assumptions regarding schedule, capital cost, generation and non-fuel operating expenses by option.

The dollar value assigned to generation is a key assumption. For all but two options, it is assumed that generation would offset grid purchases at the project site. In the cases of B11-R13 and Terminal Park Reservoir, generated power exceeds site requirements and would be sold back to Rocky Mountain Power (RMP).

In all instances, the energy generated (e.g. kWh) is assigned a value based on applicable Rocky Mountain Power rates. It is assumed that the solar PV and hydroelectric technologies offer no capacity value whether applied as an offset to purchases or exported to the grid. A capacity value is attributed to cogeneration at the wastewater plant. Specifically, it is assumed that on-site generation capacity at the SLCWRF displaces an equal amount of demand, but incurs demand charges associated with back-up power.

Table 5- 2. Schedule, Capital Cost and Non-Fuel Operating Expense Assumptions

STRATEGY TABLE																
SCHEDULE, CAPITAL COST, GENERATION, AND NON-FUEL OPERATING EXPENSE																
	Description															
							"Overnite" Capital Cost 2014$ Millions				Average Annual Generation, MWh					
							Total	Expenditure Schedule % of Total			Summer Season		Winter Season			
Scenario / Project Alternative	Project Site	Site Type	Type of Wastewater Treatment Process	Type of Power Technology	Effective Generation Capacity kW	In Service Date		FYE 2015	FYE 2016	FYE 2017	On-Peak	Off-Peak	On-Peak	Off-Peak	Total	Non-Fuel Operating Expense 2014 $000/Yr
BAU	All Sites	General	Current	Existing Recip (Run 1)	1,320		$0.0				519	1,662	1,439	1,583	5,203	$156
1	15th East Reservoir	Water Storage Reservoir		Solar PV	274	07/01/16	$0.9	35%	65%		150	31	130	24	335	$13
3	B11-R13	PRV in Transmission	NA	Hydroelectric	190		$1.0	5%	39%	56%	187	248	148	189	773	$15
4	Mountain Dell Dam	Surface Water		Hydroelectric	260	07/01/17	$1.6	5%	39%	56%	245	197	139	108	690	$19
5	Terminal Park Reservoir	Water Storage Reservoir		Solar PV	3,488		$11.3	15%	65%	20%	1,982	403	1,774	330	4,489	$150
1_WRF				Existing Recip (Run 1)	1,320		$0.0				519	1,662	1,439	1,583	5,203	$156
2_WRF				Existing Recip (Run 2 No NG)	1,320		$0.0				774	2,477	2,145	2,360	7,756	$233
3_WRF				Existing Recip (Run 2 with NG)	1,320		$0.0				883	2,825	2,447	2,691	8,846	$265
4_WRF			Current	New Recip	1,390		$9.4				904	2,893	2,505	2,756	9,058	$181
5_WRF				Microturbine	844	07/01/15	$6.7	100%			632	2,021	1,750	1,925	6,327	$221
6_WRF	SLC Water Reclamation Facility (WRF)	Wastewater		Fuel Cell	1,330		$12.1				1,037	3,318	2,874	3,161	10,390	$484
1_WRF_BNR				Existing Recip (Run 1)	1,320		$0.0				471	1,506	1,304	1,435	4,716	$141
3_WRF_BNR				Existing Recip (Run 2 with NG)	1,320		$0.0				883	2,825	2,447	2,691	8,846	$265
4_WRF_BNR			Biological Nutrient Removal	New Recip	827		$8.6				538	1,720	1,490	1,639	5,387	$108
5_WRF_BNR				Microturbine	562	07/01/15	$5.3	100%			420	1,345	1,164	1,281	4,210	$147
6_WRF_BNR				Fuel Cell	855		$10.7				667	2,133	1,847	2,032	6,679	$334

For those options where generation offsets purchases, the specific values assigned per kWh and kW of generation are based on current charges in the electric service schedule that applies to each site. The relevant schedules are 6A, 9, and 31. **Table 5- 3** indicates which schedule applies to each site and sets

forth values assigned to generation based on relevant current rates. All charges under Schedules 6A, 9, and 31 are projected to increase at 2.85% per year.

Through 2037, sales of energy back to the grid from generation facilities at Terminal Park Reservoir are attributed annual prices that are set forth in RMP Electric Service Schedule No. 37. After 2037, an annual escalation rate of 2.85% is applied. The current annual price paid for customer generation under Schedule 37 is shown in **Table 5-3**.

Under certain options, available digester gas at the SLCWRF must be supplemented with natural gas to produce power and heat for the plant. Carollo estimated the average annual plant heat requirements and fuel balances including available digester gas and required supplemental natural gas. These amounts are shown for each SLCWRF option in **Table 5-4**. The fuel balances are different at the SLCWRF depending on the wastewater treatment process. The differences arise because of the variance in plant heat and power requirements and available digester gas under the BNR and current treatment processes.

Table 5-3. Electric Service Schedule and Relevant Current Rates by Generation Option

STRATEGY TABLE

ELECTRIC SERVICE SCHEDULE AND CURRENT RATES BY GENERATION OPTION

Scenario / Project Alternative	Description						Value of Generated Power , 2014$						
							Summer Season			Winter Season			
	Project Site	Site Type	Type of Wastewater Treatment Process	Type of Power Technology	Use of Generation	RMP Electricity Service Schedule	Energy Charges per MWh On-Peak	Energy Charges per MWh Off-Peak	Demand Charges per kW Monthly On-Peak	Energy Charges per MWh On-Peak	Energy Charges per MWh Off-Peak	Demand Charges per kW Monthly On-Peak	Calculated Average Cost of Grid Power per MWh
BAU	All Sites	General	Current	Existing Recip (Run 1)	Offset Grid Purchases	Various							$87
1	15th East Reservoir	Water Storage Reservoir	NA	Solar PV		RMP 6A	$117	$35		$98	$30		
3	B11-R13	PRV in Transmission		Hydroelectric	Sell to Grid	RMP 37	$31			$31			
4	Mountain Dell Dam	Surface Water		Hydroelectric	Offset Grid Purchases	RMP 6A	$117	$35		$98	$30		
5	Terminal Park Reservoir	Water Storage Reservoir		Solar PV	Sell to Grid	RMP 37	$31			$31			
1_WRF	SLC Water Reclamation Facility (WRF)	Wastewater	Current	Existing Recip (Run 1)	Offset Grid Purchases	RMP 31 (9)	$44	$28	$13	$34	$28	$9	
2_WRF				Existing Recip (Run 2 No NG)									
3_WRF				Existing Recip (Run 2 with NG)									
4_WRF				New Recip									
5_WRF				Microturbine									
6_WRF				Fuel Cell									
1_WRF_BNR			Biological Nutrient Removal	Existing Recip (Run 1)		RMP 31 (9)							
3_WRF_BNR				Existing Recip (Run 2 with NG)									
4_WRF_BNR				New Recip									
5_WRF_BNR				Microturbine									
6_WRF_BNR				Fuel Cell									

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Table 5-4. Heat Requirements and Fuel Balances by SLCWRF Generation Option

STRATEGY TABLE											
HEAT REQUIREMENTS AND FUEL BALANCES BY SLCWRF GENERATION OPTION											
	Description										
				WRF Plant Heat Requirements Average MMBtu				WRF Fuel Balances Average MMBtu			
Scenario / Project Alternative	Project Site	Type of Wastewater Treatment Process	Type of Power Technology	Total Plant Heat	Total Useful Produced by Cogen	Supple-mental Required from Boiler	WRF Plant Power Required Average MWh	Total Fuel Consumed	Digester Gas Available	Flared Digester Gas	Natural Gas Consumed
1_WRF	SLC Water Reclamation Facility (WRF)	Current	Existing Recip (Run 1)	26,250	26,310	301	10,858	66,151	97,637	31,486	-
2_WRF			Existing Recip (Run 2 No NG)		38,851	-		97,128		509	-
3_WRF			Existing Recip (Run 2 with NG)		44,727	-		111,818		-	14,181
4_WRF			New Recip		35,333	-		88,333		9,304	-
5_WRF			Microturbine		27,091	44		77,457		20,180	-
6_WRF			Fuel Cell		19,863	6,388		94,582		3,654	599
1_WRF_BNR		Biological Nutrient Removal	Existing Recip (Run 1)	25,477	23,844	1,634	13,029	61,651	59,672	-	1,979
3_WRF_BNR			Existing Recip (Run 2 with NG)		44,727	-		111,818		-	52,146
4_WRF_BNR			New Recip		21,012	4,466		58,111		1,850	289
5_WRF_BNR			Microturbine		18,025	7,452		60,816		418	1,562
6_WRF_BNR			Fuel Cell		19,863	-		71,555		-	11,883

Further assumptions with respect to non-fuel operating expense; inflation and escalation; plant operating parameters; greenhouse gas emissions coefficients; and cash flow treatment are captured in **Table 5-5**.

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Table 5- 5. Miscellaneous Assumptions

MISCELLANEOUS ASSUMPTIONS					
Description		Value	Unit	Source	Comment
Electricity and Fuel					
Electricity					
Renewable Energy/Green Power Credit	$	-	$/MWh	Energy Strategies	Sensitivity to GHG emissions value used instead
Natural Gas					
Delivered	$	5.12	per MMBtu/HHV	Energy Strategies	Starting value for FYE June 2015
Operation and Maintenance					
Water Recalamation Facility					
WRF - Existing Reciprocating Engine	$	0.020	$/kWh	Carollo Engineers, Inc.	Starting value for FYE June 2015
WRF - New Reciprocating Engine	$	0.010	$/kWh	Carollo Engineers, Inc.	Starting value for FYE June 2015
WRF - Microturbine	$	0.025	$/kWh	Carollo Engineers, Inc.	Starting value for FYE June 2015
WRF - Fuel Cell:300 kW unit	$	0.040	$/kWh	Carollo Engineers, Inc.	Starting value for FYE June 2015
WRF - Fuel Cell:1400 kW unit	$	0.037	$/kWh	Carollo Engineers, Inc.	Starting value for FYE June 2015
WRF - Fuel Treatment System	$	0.010	$/kWh	Carollo Engineers, Inc.	Starting value for FYE June 2015
Inflation & Escalation					
General Inflation		1.8%	% per year	2014 EIA AEO GDP Price Deflator Index, Reference Case	
Escalation Factors					
Capital Cost		1.8%	% per year	Energy Strategies	
Electricity					
Base Cost		2.85%	% per year	Energy Strategies	
Value of Generated Electricity		2.85%	% per year	Energy Strategies	
Natural Gas		4.0%	% per year	2014 EIA AEO, Reference Case, Mountain, Commercial	
Non-Fuel O&M		1.8%	% per year	Energy Strategies	
GHG Emissions Compliance Value		1.8%	% per year	Energy Strategies	
Plant Operating Parameters					
Boiler Plant Efficiency		80%	MMBtu Heat per MMBtu of Fuel	Carollo Engineers, Inc.	
Greenhouse Gas Emissions Coefficients					
Purchased Electricity					
Current		0.75	MTCO2e/MWh	SLC DPU	Starting value for FYE June 2015
EPA Target Reduction: 2030		27%		Energy Strategies	EPA Clean Power Plan Proposed Rule
Global Warming Potential					
CH4 Emissions		34	100 years	2013 IPCC AR5 p714	
N20 Emissions		298	100 years	2013 IPCC AR5 p714	
Natural Gas: Stationary Combustion					
CO2 Emissions		53.06	kg/MMBtu	The Climate Registry GRP V1.1, Table 12.1	
CH4 Emissions					
Engine Generators		0.5669	kg/MMBtu	The Climate Registry GRP V1.1, Table 12.1	
Turbines		0.0038	kg/MMBtu	The Climate Registry GRP V1.1, Table 12.1	
Fuel Cells		0.0009	kg/MMBtu	The Climate Registry GRP V1.1, Table 12.1	
N2O Emissions		0.0009	kg/MMBtu	The Climate Registry GRP V1.1, Table 12.1	
Total					
Engine Generators		0.0726	MTCO2e/MMBtu	Calculated	
Turbines		0.0535	MTCO2e/MMBtu	Calculated	
Fuel Cells		0.0534	MTCO2e/MMBtu	Calculated	
Digester Gas: Stationary Combustion/Boiler					
CO2 Emissions		53.06	kg/MMBtu	The Climate Registry GRP V1.1, Table 12.1	
CH4 Emissions		0.0009	kg/MMBtu	The Climate Registry GRP V1.1, Table 12.1	
N2O Emissions		0.0009	kg/MMBtu	The Climate Registry GRP V1.1, Table 12.1	
Total Boiler		0.0534	MTCO2e/MMBtu	Calculated	
Digester Gas: Stationary Combustion					
CO2 Emissions		52.07	kg/MMBtu	The Climate Registry GRP V1.1, Table 12.1	
CH4 Emissions		0.0009	kg/MMBtu	The Climate Registry GRP V1.1, Table 12.1	
N2O Emissions		0.0001	kg/MMBtu	The Climate Registry GRP V1.1, Table 12.1	
Total Stationary Combustion Other		0.0521	MTCO2e/MMBtu	Calculated	
Greenhouse Gas Compliance Value					
As Modeled	$	-	2014$/MTCO2e		
Sensitivity Case	$	25.00	2014$/MTCO2e		
Sensitivity Case	$	50.00	2014$/MTCO2e		
Cash Flow Treatment					
Type of Year		Fiscal		Energy Strategies	
Year End Date		June 30th		SLC DPU	
Discount Date		1-Jul-14		Energy Strategies	
Discount Rate		5.0%		SLC DPU	

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Applying the assumptions described above, the “incremental” analysis provides insight with respect to the benefits and trade-offs resulting when a course of action is pursued that is different from business as usual. The economic model measures changes (increases and (decreases)) in the following measures for each option versus the relevant business as usual scenario:

- On-site generating capacity, kW
- "Overnite" capital, 2014$ millions
- Average annual generation, MWh
- Non-fuel operating expense, 2014$ millions
- Average annual supplemental natural gas required, MMBtu
- Digester gas flared, % of total available
- GHG emissions, MTCO2e
- Present value cost of utility service, $ millions
  - As modeled assuming $0 per MTCO2e compliance cost
  - Sensitivity analysis at $25 and $50 per MTCO2e compliance cost.

Conclusions

Summary results with respect to these measures are shown in **Table 5-6**. The summary results indicate the following:

- If "cost effective" is defined as not increasing the cost of utility service, the solar projects are not cost effective and the hydroelectric projects become cost effective only assuming a significant cost is assigned to GHG emissions, e.g. between $25 and $50 per MTCO2e.
- There is an opportunity to generate a significant amount of power using solar PV technology at Terminal Park Reservoir. However, there is insufficient value assigned to power sold to the grid to recover the capital investment in such a facility. Even at the 15th East Reservoir where solar PV generation displaces purchases, the value attributed to GHG abatement would need to be in excess of $50 per MTCO2e to recover the invested capital.
- To the extent generation at the SLCWRF is currently being limited to one engine, there appears to be an economic opportunity to operate the existing two engines and consume more of the available digester gas, lowering the cost of utility service and GHG emissions. All new generation options considered for the SLCWRF entail significant incremental capital (between $5 and $12 million) and would result in an increase in the cost of utility service even if a value of $50 per MTCO2e is attributed to GHG emissions.

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Table 5-6. Economic Analysis - Summary Incremental Benefits and Trade-Offs

STRATEGY TABLE																	
ECONOMIC ANALYSIS - SUMMARY INCREMENTAL BENEFITS AND TRADE-OFFS																	
	Description																
							Increase (Decrease) vs. Comparison Scenario										
							On-Site Generating Capacity	"Overnite" Capital	Average Annual Generation	Self Generation to Total Required	Non-Fuel Operating Expense	Average Annual Natural Gas Supplement Required	Digester Gas Flared	Average Annual GHG Emissions	Cost of Utility Service Present Value $Millions		
Scenario / Project Alternative	Project Site	Site Type	Type of Wastewater Treatment Process	Type of Power Technology	Use of Generation	Scenario Used for Comparison	kW	2014$ Millions	MWh	%	2014$ Millions	MMBtu	% of Available	MTCO2e	$0 per MTCO2e	$25 per MTCO2e	$50 per MTCO2e
BAU	All Sites	General	Current	Existing Recip (Run 1)	Offset Grid Purchases	No Cogen	1,320	$0.0	5,203		$156	0	-34%	-3,271			
1	15th East Reservoir	Water Storage Reservoir	NA	Solar PV		BAU	274	$0.9	335		$13			-252	$0.4	$0.3	$0.2
3	B11-R13	PRV in Transmission		Hydroelectric	Sell to Grid		190	$1.0	773		$15			-582	$0.6	$0.3	($0.1)
4	Mountain Dell Dam	Surface Water		Hydroelectric	Offset Grid Purchases		260	$1.6	690		$19			-520	$0.4	$0.1	($0.2)
5	Terminal Park Reservoir	Water Storage Reservoir		Solar PV	Sell to Grid		3,488	$11.3	4,489		$150			-3,381	$10	$9	$7
1_WRF	SLC Water Reclamation Facility (WRF)	Wastewater	Current	Existing Recip (Run 1)	Offset Grid Purchases												
2_WRF				Existing Recip (Run 2 No NG)		1_WRF	0	$0.0	2,553	24%	$77	0	-32%	-1,558	($1)	($2)	($3)
3_WRF				Existing Recip (Run 2 with NG)			0	$0.0	3,642	34%	$109	14,181	-32%	-1,233	($0)	($1)	($1)
4_WRF				New Recip			70	$9.4	3,855	36%	$25	0	-23%	-2,394	$6	$5	$4
5_WRF				Microturbine			-476	$6.7	1,124	10%	$65	0	-12%	-698	$6	$6	$6
6_WRF				Fuel Cell			10	$12.1	5,187	48%	$328	599	-29%	-3,184	$12	$11	$10
1_WRF_BNR			Biological Nutrient Removal	Existing Recip (Run 1)													
3_WRF_BNR				Existing Recip (Run 2 with NG)		1_WRF _BNR	0	$0.0	4,130	32%	$124	50,167	0%	1,061	$3	$3	$4
4_WRF_BNR				New Recip			-493	$8.6	671	5%	($34)	-1,689	3%	-549	$7	$7	$7
5_WRF_BNR				Microturbine			-758	$5.3	-506	-4%	$6	-417	1%	248	$6	$6	$6
6_WRF_BNR				Fuel Cell			-465	$10.7	1,964	15%	$193	9,904	0%	-729	$12	$12	$12

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References

Alpha Engineering and RB&G, Inc. 2014. Pre-Design Report for Mountain Dell Bypass and Hydro Project. Salt Lake City Department of Public Utilities.

U.S. National Renewable Energy Laboratory. Unknown. Solar Radiation for Flat-Plate Collectors Facing South in Salt Lake City, Utah. Available at http://rredc.nrel.gov/solar/old_data/nsrdb/1961-1990/redbook/sum2/24127.txt. Accessed on July 15, 2014.

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Public Utilities

2019-2020 Budget Proposal

April 23, 2019

2019-2020 Proposed Budget Overview

Total Proposed Budget: $298,107,775

- Revenues projected at $249,137,157; reserve use $48,970,618 (Balance of 2017 Bond Issue).
- Proposed 5% water, 18% sewer, and 10% stormwater rate increases.
- Capital Investments (Capital Outlay and Improvements) - $184,026,196.
- Operations - $97,435,579.
- 17 additional FTEs – bringing staffing from 422.50 to 439.50 full time equivalent employees.

Public Utilities

Water Utility

Proposed Water Utility Budget:

$129,821,317

- Water service fees and reserve funds contribute to most of the projected revenue, at $75,731,453 and $13,346,707, respectively
- Revenue bonds proposed at $35,196,000
- A rate increase of 5% is proposed
- Capital investments of $61,764,547 and operation expenses at $66,275,770.
- Capital program emphasis on treatment plants, water mains, wells, and reservoirs.

Public Utilities

Sewer Utility

Proposed Sewer Utility Budget:

$141,544,664

- Sewer fees and reserves comprise most of the Sewer Utility’s projected revenue, at $44,460,000 and $38,198,664, respectively. Reserve funds are primarily from 2017 bond issue.
- New bonds $55,307,000.
- Debt service payments 13,456,000
- A rate increase of 18% is proposed.
- Capital Improvements of $98,370,500 and operations at $21,024,164.

Public Utilities

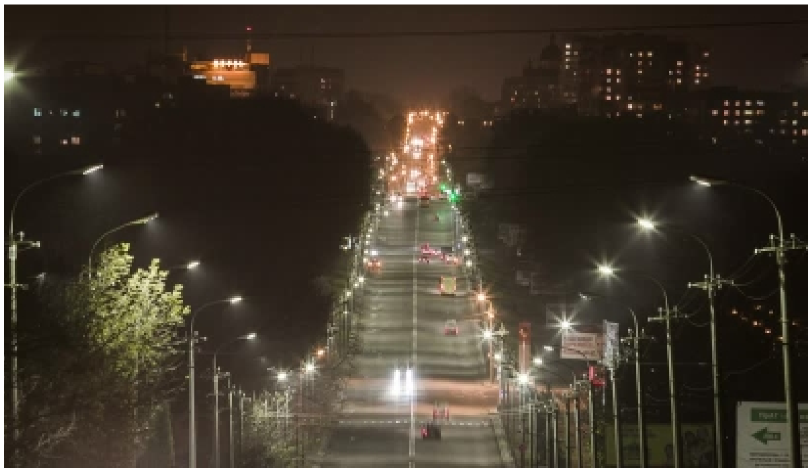
Stormwater Utility

Proposed Stormwater Utility Budget:

$21,950,517

- Stormwater fees and bonding at $9,740,500 and $14,581,000 comprise most of the projected revenue.
- Capital improvement program $12,744,000, and operations at $7,172,368
- A 10% rate increase is proposed.
- Collection lines are primary capital investment - $12,530,000

Street Lighting Utility



Total Proposed Street Light Utility

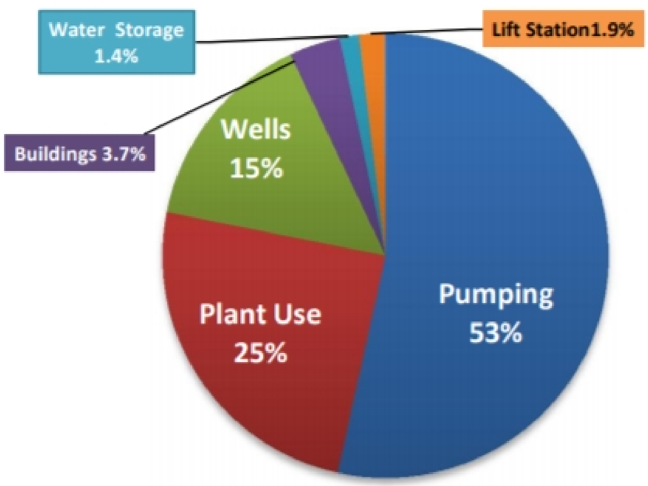
Fiscal Year 2019-20 Budget: $4,791,277

- Street light fees and reserves account for the majority of projected revenue, at $4,198,227 and $534,050, respectively. Reserves are primarily unspent bond proceeds from 2017 bond issue.
- Capital improvement program $1,725,000 and operations at $2,963,277
- Continued upgrades to high efficient lighting
- Update of City's 2006 Street Light Master Plan

Public Utilities

Energy/Carbon Goals

Figure 3-2. Energy Consumed by End Use



<u>Energy Efficiency and Renewable Energy Investments FY 2019-2020</u>

- Parleys hydropower project
- Wire to water efficiency projects
- Sustainability manager
- Smart meter replacement
- Water conservation plan
- Treatment plant upgrades
- Climate studies

Public Utilities

Rate Impact Summary

Public Utilities

Projected 5-Year Rate Adjustments for Water, Sewer, Stormwater, and Street Lighting

Year	Water	Sewer	Stormwater	Street Lighting
2019-2020 Proposed	5%	18%	10%	0%
2020-2021	5%	18%	10%	0%
2021-2022	5%	18%	9%	0%
2022-2023	5%	15%	6%	0%
2023-2024	6%	10%	5%	0%

Public Utilities

Monthly Impact for City Residents
Water Rate Structure Changes and Overall 5% Increase

Water Rate Change
Monthly Impact on Select City Customers

Account Type	Monthly Usage	Meter Size	2019 Current Rate	2020 Proposed Rate	$ Change	% Change
Residential Minimum Use	6 ccf	3/4	17.99	17.50	(0.49)	-2.72%
Residential Low Use	8 ccf	3/4	20.69	20.24	(0.45)	-2.17%
Residential Medium Use	21 ccf	3/4	46.60	46.41	(0.18)	-0.40%
Residential High Use	70 ccf	1	164.43	168.08	3.65	2.22%
Industrial Use	8,040 ccf	2	11,712.73	12,605.91	893.18	7.63%
Commercial Use	966 ccf	2	1,363.81	1,473.74	109.94	8.06%

Public Utilities

Monthly Impact for Residents Outside Salt Lake City – Water Rate Structure Changes and Overall 5% Water Rate Increase

Water Rate Change
Monthly Impact on Select County Customers

Account Type	Monthly Usage	Meter Size	2019 Current Rate	2020 Proposed Rate	$ Change	% Change
Residential Minimum Use	6 ccf	3/4	24.29	23.63	(0.66)	-2.72%
Residential Low Use	8 ccf	3/4	27.93	27.32	(0.61)	-2.17%
Residential Medium Use	21 ccf	3/4	62.91	62.66	(0.25)	-0.40%
Residential High Use	70 ccf	1	221.98	226.91	4.92	2.22%
Industrial Use	8,040 ccf	2	15,812.19	17,017.98	1,205.80	7.63%
Commercial Use	966 ccf	2	1,841.14	1,989.55	148.41	8.06%

Monthly Impact for Residents with Sewer Rate Structure Changes and Overall 18% Sewer Rate Increase

Sewer Rate Change
Monthly Impact on Select City Customers

		2019	2020		
Account Type	**Annualized Average Winter Water Usage (CCF)**	**Current Rate**	**Proposed Rate**	**$ Changes**	**% Change**
Residential Minimum Use	2 ccf	12.16	7.34	(4.82)	-39.64%
Residential Low Use	4 ccf	12.16	14.68	2.52	20.72%
Residential Medium Use	8 ccf	24.32	29.36	5.04	20.72%
Residential High Use	15 ccf	45.60	55.05	9.45	20.72%
Industrial 2, 4	2,014 ccf	10,150.56	11,499.94	1,349.38	13.29%
Commercial 2,1	34 ccf	120.36	127.50	7.14	5.93%

*Industrial & Commercial charges are calculated based on flow rate, BOD and TSS

Public Utilities

Five Year Projection for Monthly Sewer Rates

	Rates						
Proposed Budget and Forecast of Rates by Customer Class	Current Rate	Proposed Budget 2019-20	Projected Budget 2020-21	Projected Budget 2021-22	Projected Budget 2022-23	Projected Budget 2023-24	5 Year Impact
	Current	18%	18%	18%	15%	10%	
Residential Minimum Use	12.16	7.34	8.66	10.22	11.75	12.93	6.33%
Residential Low Use	12.16	14.68	17.32	20.44	23.51	25.86	112.66%
Residential Medium Use	24.32	29.36	34.64	40.88	47.01	51.71	112.62%
Residential High Use	45.60	55.05	64.96	76.65	88.15	96.97	112.65%
Industrial 2, 4	10,150.56	11,499.94	13,569.93	16,012.52	18,414.40	20,255.84	99.55%
Commercial 2,1	120.36	127.50	150.45	177.53	204.16	224.58	86.59%

*Industrial & Commercial charges are calculated based on flow rate, BOD and TSS

Public Utilities

Rate Comparisons

Public Utilities

Water Rates Compared With Nearby States

Water Rates Compared with Recognizable Cities in Western States

Ranking	City or District Name	Average Monthly Charge
1	Flagstaff, AZ (1)	$ 121.40
2	Cheyenne, WY (2)	$ 68.60
3	Denver, CO (3)	$ 56.34
4	Reno, NV (4)	$ 51.14
5	Phoenix, AZ (5)	$ 44.67
6	Boise, ID (6)	$ 44.44
7	Las Vegas, NV (7)	$ 42.26
8	Salt Lake City, UT- 2019 Current	$ 37.44
	Salt Lake City, UT- 2020 Proposed	$ 37.17
9	Henderson, NV (8)	$ 26.47

* Cities compared with 7,480 gallons per month (10 CCF) and 24,000 gallons summer usage (32.09 CCF).
** Based on eight months Winter and four months Summer usage

Public Utilities

Public Utilities Department Local Area Water Rate Comparison November 2018 (Highest to Lowest Ranking)

RANKING	CITY OR DISTRICT NAME	MONTHLY MINIMUM CHARGE	MINIMUM ALLOWANCE IN GALLONS	RATE OVER MINIMUM ALLOWANCE	PER GALLONS	MONTHLY FLOURIDE CHARGE	WINTER @ 7,480 GAL PER MONTH	SUMMER @ 23,936 GAL PER MONTH	TOTAL WINTER CHARGES*	TOTAL SUMMER CHARGES*	YEARLY TAX ON $200,000 PROPERTY	TOTAL CHARGES
1	PARK CITY - GRADUATED RATES (1)	49.08	0	6.12 - 10.31	1,000		104.01	269.91	832.07	1079.64		1911.71
2	AMERICAN FORK - GRADUATED RATES (2)	22.67	3,000	3.52 - 4.96	1,000		39.51	120.03	316.04	480.13		796.17
3	DRAPER CITY - GRADUATED RATES (3)	20.25	0	2.05 - 3.71	1,000		39.08	97.00	312.65	388.01		700.66
4	SOUTH JORDAN CITY - GRADUATED RATES (4)	30.00	0	2.00 - 2.50	1,000		45.33	84.09	362.64	336.36		699.00
5	RIVERTON CITY - GRADUATED RATES (5)	2.50	0	3.76 - 3.91	1,000		31.00	95.34	247.97	381.36		629.33
6	PLEASANT GROVE - GRADUATED RATES (6)	20.81	5,000	2.52 - 5.27	1,000		27.06	98.90	216.48	395.61		612.09
7	OGDEN CITY - GRADUATED RATES (7)	20.90	0	1.79 - 2.74	1,000		35.70	80.78	285.56	323.14		608.70
8	SALT LAKE CITY - OUTSIDE OF CITY	13.35	0	1.82 - 3.47	748		31.55	88.49	252.40	353.96		606.36
	SALT LAKE CITY - OUTSIDE OF CITY (Proposed)	12.53	0	1.84 -3.50	748		30.93	88.33	247.44	353.32		600.76
9	SANDY CITY - OUTSIDE OF CITY (8)	19.95	0	1.80 - 2.75	1,000		34.82	80.07	278.56	320.30		598.86
10	WEST JORDAN CITY (11)	26.58	0	1.65 - 2.18	1,000		39.04	71.41	312.34	285.64		597.98
11	KEARNS IMPROVEMENT DIST-GRADUATED RATES (9)	11.60	0	2.33 - 2.92	1,000		29.03	75.59	232.23	302.37	51.04	585.64
12	MAGNA - GRADUATED RATES (10)	17.41	6,000	1.89 - 2.12	1,000	0.98	21.19	53.65	169.50	214.62	178.81	562.92
13	SANDY CITY - INSIDE OF CITY (12)	14.43	0	1.64 - 2.53	1,000		28.01	69.65	224.12	278.59	35.75	538.46
14	SALT LAKE CITY - INSIDE OF CITY (13)	9.89	0	1.35 - 2.57	748		23.39	65.53	187.12	262.12	33.22	482.46
	SALT LAKE CITY - INSIDE OF CITY (Proposed)	9.28	0	1.37 - 2.59	748		22.98	65.56	183.84	262.24	35.75	481.83
15	BOUNTIFUL CITY - RESIDENTIAL HIGH ELEVATION	23.57	5,000	1.98	1,000		28.48	61.06	227.84	244.25		472.10
16	CITY OF SOUTH SALT LAKE	19.00	5,000	2.25	1,000	2.00	26.58	63.61	212.64	254.42		467.06
17	GRANGER - HUNTER IMPROVEMENT DISTRICT (14)	13.00	0	1.61 -1.86	1,000		25.10	54.73	200.80	218.92	28.55	448.27
18	BOUNTIFUL CITY - RESIDENTIAL LOW ELEVATION	21.39	5,000	1.79	1,000		25.83	55.29	206.63	221.14		427.78
19	JVWCD	3.00	0	1.87 - 2.34	1,000		16.99	59.01	135.90	236.04	44.00	415.94
20	PROVO	15.29	0	0.87 - 1.44	1,000		21.80	49.76	174.38	199.03		373.41
21	TAYLORSVILLE/BENNION IMPROVEMENT DISTRICT (15	7.00	0	1.43 - 1.87	1,000		18.35	49.12	146.78	196.48	6.88	350.14
22	MURRAY CITY - GRADUATED RATES (16)	10.00	0	0.95 - 1.40	748		19.90	46.95	159.20	187.80		347.00
23	OREM - GRADUATED RATES (17)	17.16	0	0.79 - 0.99	1,000		23.07	38.66	184.55	154.63		339.18

CALCULATION OF COMPARISONS

** BASED ON EIGHT MONTHS WINTER AND FOUR MONTHS SUMMER*
(1) RATES ARE $6.12/THOUSAND FOR 0-5.000 GALLONS. $9.81/THOUSAND FOR 5.001-15.000 GALLONS. & $10.31/THOUSAND FOR 15.001-25.000 GALLONS
(2) RATES ARE $22.67 FOR 0-3.000 GALLONS. $3.52/THOUSAND FOR 3.001-6.000 GALLONS. $4.24/THOUSAND FOR 6.000-9.000 GAL & $4.96/THOUSAND OVER 9.000 GALLONS
(3) RATES ARE $2.05/THOUSAND FOR 0-5.000 GALLONS. $3.46/THOUSAND FOR 5.001-20.000 GALLONS. & $3.71/THOUSAND FOR 20.001-50.000 GALLONS
(4) RATES ARE $2.00/THOUSAND FOR 0-6.000 GALLONS. $2.25/THOUSAND FOR 6.001-17.000 GALLLONS & $2.50/THOUSAND FOR 17.001 - 42.000 GALLONS
(5) RATES ARE $3.76 FOR 0-5.000 GALLONS & $3.91/THOUSAND OVER 5.000 GALLONS
(6) RATES ARE $20.81 FOR 0-5.000 GALLONS. $2.52/THOUSAND FOR 5.001-10.000 GALLONS. $3.68/THOUSAND FOR 10.001-15.000 GALLONS & $5.27/THOUSAND OVER 15.000 GALLONS
(7) RATES ARE $1.79/THOUSAND FOR 0-6.000 GALLONS & $2.74/THOUSAND FOR 6.001-42.000 GALLONS
(8) RATES ARE $1.80/THOUSAND FOR 0-6.000 GALLONS & $2.75/THOUSAND FOR 6.001-40.000 GALLONS
(9) RATES ARE $2.33/THOUSAND FOR 0-10.000 GALLONS & $2.92/THOUSAND FOR 10.001-25.000 GALLONS
(10) RATES ARE $1.64/THOUSAND FOR 0-6.000 GALLONS & $2.53/THOUSAND FOR 6.001-40.000 GALLONS
(11) RATES ARE $17.41 FOR 0-6.000 GALLONS. $1.89/THOUSAND FOR 6.001-18.000 GALLONS. & $2.12/THOUSAND FOR 18.001-35.000 GALLONS
(12) RATES ARE $1.65 FOR 0-7.000 GALLONS. $1.90/THOUSAND FOR 7.001-20.000 GALLONS. & $2.18/THOUSAND FOR OVER 20.000 GALLONS
(13) INCLUDES METROPOLITAN WATER PROPERTY TAX
(14) RATES ARE $1.61/THOUSAND FOR 0-7,000 GALLONS, $1.73/THOUSAND FOR 7,001-15,000 GALLONS & $1.86/THOUSAND FOR OVER 15,000 GALLONS
(15) RATES ARE $1.43/THOUSAND FOR 0-6,000 GALLONS & $1.87/THOUSAND FOR 6,001-25,000 GALLONS
(16) RATES ARE $.95/HUNDRED FOR 0-8 HCF, $1.15/HUNDRED FOR 9-25 HCF & $1.40/HUNDRED FOR 26-49 HCF
(17) RATES ARE $.79/THOUSAND FOR 0-11,000 GALLONS, $.99/THOUSAND FOR 11,001-34,000 GALLONS

Public Utilities

Sewer Rates Compared with Nearby States

City or District Name	Average Monthly Charges
Reno, NV	$ 46.77
Boise, ID **	$ 43.33
Phoenix, AZ **	$ 37.02
Flagstaff, AZ	$ 29.92
Cheyenne, WY **	$ 29.32
Salt Lake City- 2020 Proposed	$ 29.36
Denver, CO	$ 26.99
Henderson, NV	$ 25.78
Salt Lake City- 2019 Current	$ 24.32
Las Vegas, NV	$ 19.76

* Monthly Average Charges calculated based on 5,984 gallons per month (or 8 CCF)
** Includes Monthly base rate

Public Utilities

Sewer Rates Compared with Local Cities

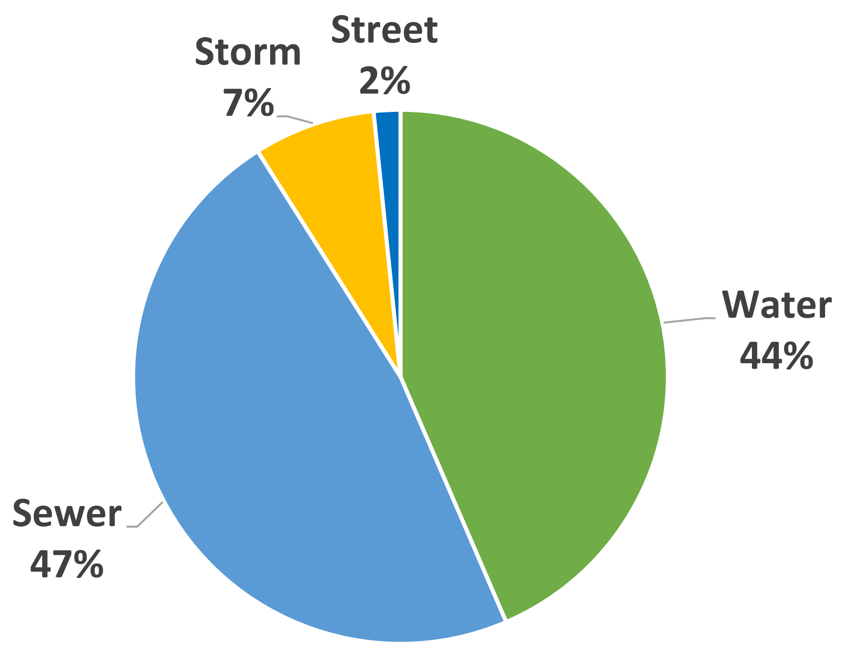
Ranking	City or District Name	Annual Charge
1	City of South Salt Lake	$ 502.66
2	Kearns Improvement District	$ 425.34
3	Magna City	$ 381.63
4	Ogden City	$ 364.56
	Salt Lake City- 2020 Proposed	$ 352.32
5	South Valley Sewer District	$ 332.56
6	Murray City **	$ 323.63
7	West Jordan City **	$ 323.09
8	Granger - Hunter Improvement District	$ 322.55
9	Midvalley Improvement District	$ 295.29
10	Salt Lake City- 2019 Current	$ 291.84
11	Taylorsville - Bennion Improvement District**	$ 265.95
12	Cottonwood Improvement District	$ 259.36
13	Sandy Suburban Improvement District	$ 257.04
14	Mt Olympus Improvement District	$ 234.69
15	South Davis Sewer District	$ 146.95

* Annual cost based on 12 months at 5,984 gallons per month (or 8 CCF per month) average winter consumption. Flat rate based on monthly rate multiplied by 12.

** Includes monthly base rate

Discussion

Department of Public Utilities FY 2020 Budget By Fund



COUNCIL STAFF REPORT

CITY COUNCIL *of* SALT LAKE CITY

Item Schedule:
Briefing: April 23, 2019
Public Hearing:
Potential Action:

TO: City Council Members

FROM: Sam Owen, Policy Analyst

DATE: April 23, 2019

RE: FISCAL YEAR 2019-20 BUDGET,
DEPARTMENT OF PUBLIC UTILITIES,
Water, Sewer, Stormwater, and Street Lighting Funds

ISSUE AT-A-GLANCE

The Mayor's Recommended Budget for the Department of Public Utilities includes the Water, Sewer, Stormwater, and Street Lighting Enterprise Funds, totaling $298,017,775 for capital and operating expenses for the fiscal year 2020. Major budget items include system upgrades and expansions in response to aging infrastructure and new regulatory requirements, and 17 new staff positions related to the significant capital projects scheduled over the coming years.

These four Utilities are Enterprise Funds, operating more or less like businesses separate from the General Fund. Each fund generates revenue through user fees and has separate staff, materials and supply budgets and capital improvement programs. The management and administration of the four funds is all under the Department of Public Utilities.

SUPPLEMENTAL COMPONENTS

The Department also transmitted a proposed resolution that, if approved, would convey the Council's support for the new water reclamation facility (WRF). The resolution contains information about the project's budget as well. The resolution is required by the Utah Department of Environmental Quality (UDEQ) as a condition on its granting a regulatory variance for the current reclamation facility. The variance is required because regulatory compliance will only be achieved once the new plant is operational, by 2025. This item is Attachment 2.

Another proposal before the Council is the ordinance that would adopt a new rate structure for the Water, Sewer and Stormwater Utilities. The Council was briefed on the new proposed rate structure October 2, 2018. More information on this item is found beginning page 3 of this report. Attachments 3 and 4 pertain to this item.

The Department also provided a final copy of its Renewable Energy Plan, which outlines goals and methods for carbon reduction across the Utilities. See Attachment 5. It is Council staff understanding that preparation of this kind of carbon mitigation/reduction planning was a major component of this year's Citywide budget proposal process.

Attachments
Attachment 1, Public Utilities proposed budget
Attachment 2, Water reclamation facility resolution of support
Attachment 3, Rate structure ordinance
Attachment 4, October 2018 Council rate study briefing
Attachment 5, Public Utilities renewable energy plan

Some of the other major items in this budget document include:

- **Rate increases:** 18 percent this year in the Sewer Utility, 10 percent in the Water Utility, and 10 percent in the Stormwater Utility. See more about these increases, beginning page 3. The increases are connected in part with the need to pay debt service for bonds issued to fund significant capital improvements over the next several years. The total impact to the average household utility bill would be approximately $5.34 per month.
- **Capital projects**: capital improvements planned for this year total $172,094,600. Notably, the Sewer Utility anticipates costs for the new Water Reclamation Facility (WRF) approaching $528,130,000. The Department has applied for federal funding through the Water Infrastructure Financing Innovation Act (WIFIA), which may result in favorable loans covering up to 49% of the cost of the new WRF. Furthermore, anticipated sewer collection system capacity upgrades are budgeted for $36,630,500 during fiscal 2020; $39,132,179 is projected in terms of actual expenditures on these projects during fiscal 2019. Over $100 million is budgeted for similar projects over the subsequent four fiscal years. These are Public Utilities Master Plan projects and not infrastructure projects directly caused by new development in the City's northwest quadrant, although the timelines have been adjusted for some Master Plan collection system projects based on new construction. See more about these upgrades below.
- **Personnel-related increases**: Personal Services will increase over fiscal 2019 by $2,505,057, which includes 17 total new full-time equivalents (FTEs), a 3 percent cost-of-living adjustment (COLA), and contemplates a 7 percent increase in insurance for medical premiums. The new employees are necessary to manage capital projects, increased operational needs, and to provide for succession of key positions. COLA adjustments are included in the proposed budget as a placeholder since Enterprise Fund budgets are reviewed by separate Advisory Boards, but will be adjusted based on the salary adjustment ultimately approved for City employees.

POLICY QUESTIONS

1. Northwest Quadrant- The Council may wish to ask the following questions in order to gain a more comprehensive understanding of the Utility projects in the Northwest Quadrant.
    a. Reports from the Administration, as available, on the status of the betterments to infrastructure improvements in the Northwest Quadrant as the State Prison construction proceeds. Per the contract between the City and State, monthly reports will be generated on the status and expense of betterments—the Council may wish to receive these reports or to otherwise request information about the progress of betterments and related costs as the process unfolds.
    b. Information of how costs the City will incur in construction of betterments on infrastructure improvements related to construction of the Prison will be recouped, so existing ratepayers are not unduly burdened. For example, where new private development in the Northwest Quadrant "taps into" or benefits from implementation of these betterments, would fees be assessed attendant to the improved capacity or service to help offset the costs over longer periods of time? This might be assessed through the application of impact fees, or through other means.
    c. Which Master Plan projects have been or will be expedited, in response to increased demands for service related to new development in the Northwest Quadrant. This would help with a more

comprehensive understanding of how new development in the Northwest Quadrant could be impacting existing customers through changes in rates for services.

2. The Council may wish for a more detailed explanation of impact fees and how they are being collected and applied within the Utility. At the time of this writing, 13 Master Plan projects budgeted for implementation during the coming fiscal year are expected to be eligible for impact fees; however, this has not yet been confirmed. Council Members may wish to request follow-up and ongoing status reports with regard to the Utilities' implantation of impact fees, especially in the context of a pending, new Impact Fees Facilities Report from the Department.
3. Community members in different parts of the City have asked about the Street Lighting Utility's replacement of older lights with LED technologies emitting light in "cooler" color spectrums, resulting in "bluer" light that some experience as appearing with higher intensity. Community members have pointed to efforts by other municipalities and admonitions from particular research items to move away from these "bluer" lights to adopt "warmer" lighting. Subsequent conversations with the Council have indicated energy-efficiency was to be an ongoing and forefront consideration in replacing Street Lighting. The existing Plan does not contemplate LED technology because it had not been developed at the time of the Plan's adoption.
    a. Council Members may also wish for an update on the Street Lighting Master Plan update, for which public engagement has commenced.
    b. The Council may wish to request more information about how and when constituent feedback has been incorporated in the process of replacements, both in terms of how lights are directed and how intensity is assessed and implemented.
    c. Council Members may wish to request that the Utility continue to look into how impact fees may or may not be applicable to Street Lighting projects, now or in the future.

MAJOR ITEM DETAIL

The percentages of proposed rate increases are calculated on the basis of a new proposed rate structure for the three utilities proposing increases (Water, Sewer, Stormwater). The new proposed rate structure was presented to the Council October 2, 2018. In conjunction with the current budget, the Department proposes implementation of that rate schedule. Attachment 4 provides detailed background on the rate structure. The rate structure change itself is revenue neutral. Attachment 3 is a proposed ordinance that would adopt the new rate structure. Information on the percentage changes for the proposed rate increases *without* adoption of the new rate structure is contained in Appendix D of the Administration's Public Utilities budget proposal.

Increases in rates for the current fiscal year, as well as the years subsequent, are in response to the bonding requirements and related debt service necessary to fund the replacement, maintenance and upgrades of aging and in some cases badly deteriorated infrastructure. The replacement, maintenance and upgrades of existing infrastructure will facilitate the ongoing use and availability of the Utilities' services for current customers.

- **Water Utility**

  In conjunction with implementation of the new rate structure, the proposed rate increase of 5 percent would impact an average resident's monthly bill by reducing it about 19 cents (little to no impact). Rates are projected to increase 5 percent each year through fiscal year 2022-23. Increases are timed based on capital project needs and the related bonding to finance the projects; as part of this, rates also increased 4 percent last fiscal year. The Utility anticipates bond proceeds of $35,196,000 and $44,490,000, in the fiscal years 2020 and 2021, respectively.

- **Sewer Utility**

  In conjunction with implementation of the new rate structure, the proposed rate increase of 18 percent would impact an average resident's bill by about $5.04 each month. Rates are projected to increase 18 percent for the subsequent two fiscal years, 15 percent for fiscal 2023 and 10 percent for fiscal 2024. Increases are timed based on capital project needs and the related bonding to finance the projects; as part of this, rates also increased 30 percent last fiscal year. The Utility anticipates bond proceeds of $55,307,000 and $39,218,000 in the fiscal years 2020 and 2021 respectively. (Projected rate increases

will continue to be evaluated with each year's budget and capital project schedule, and may change as needed.)

- **Stormwater Utility**
  In conjunction with implementation of the new rate structure, the proposed rate increase of 10 percent would impact an average resident's bill by about $0.49 each month. Dwindling cash reserves, stronger regulatory requirements, and infrastructure needs are drivers for the proposed rate increase. Additional rate increases of 10 percent, 9 percent, 6 percent and 5 percent are anticipated for the four subsequent fiscal years, respectively. The Utility anticipates bond proceeds of $14.5 million in fiscal 2020, in part to fund recently-initiated flooding mitigation projects and projects implemented in relation to road work funded by the recent general obligation bond.

- **Street Lighting Utility**
  This fund will not have a rate increase this year. The Utility reports energy savings related to LED lighting upgrades of about $300,000 from the current fiscal year, and anticipates similar outcomes in future years.

Capital projects:
Improvements planned in the Water Utility have to do with strengthening service capacity and updates to aging, critical infrastructure. Some items of note:

- Treatment Plant projects
  - Upgrades at the City Creek Water Treatment Plant are budgeted for $1,500,000 this year, reflecting necessary upgrades to critical infrastructure for the treatment and conveyance of drinking water. Improvements will total an estimated $1.5 million for the four subsequent years. Phase 2 of the City Creek Plant upgrades is budgeted for an estimated $30,000,000; that expense is not planned to begin before fiscal year 2024.
  - The Parley's Water Treatment Plant will undergo improvements this year totaling an estimated $2,050,000. The subsequent fiscal year 2021 budgets for $11,250,000 in capital costs for the plant and $2,000,000 in capital costs for each additional year through fiscal 2024. The Department estimates delayed capital costs at $158,000,000, of which $136,500,000 is designated for a new Parley's Water Treatment Plant. The remainder of those delayed capital costs relates to other projects at the facility. The delayed capital expenditures are costs that the Utility anticipates as being necessary, but hasn't planned to implement in terms of the projections in the fiscal year 2020 budget proposal.
  - The Big Cottonwood Canyon Treatment Plant will undergo improvements budgeted for $4,300,000, including $2,500,000 for a number of projects related to a plant rebuild. The plant rebuild is expected to incur further costs of $5,000,000 in the subsequent fiscal year 2021 and at least $2,000,000 annually through fiscal 2024. The Department estimates an additional $156,750,000 in delayed capital costs for this specific facility in the future. The delayed capital expenditures are costs that the Utility anticipates as being necessary, but hasn't planned to implement in terms of the projections in the fiscal year 2020 budget proposal.
- Improvements and electrical system upgrades at the 4th Avenue well near Canyon Road this year is budgeted for $3,000,000; rehabilitation of the Mountain Dell Dam for $2,165,000; and the hydropower project in Parley's Canyon budgeted for another $100,000 after last year's expenditure of $1,000,054.
- A water line on 1300 East Street ran $2,417,418 last year, and energy efficiency and renewable energy capital improvements are budgeted for another $200,000 (existing in-pipe turbines are scheduled to begin generating renewable power in 2021).
- The East-West aqueduct or water conveyance line from Park Reservoir to near Sugar House Park is budgeted for $10,000,000 this year and $10,000,000 in the subsequent year. The line is expected to expand capacity for service to the City's Northwest Quadrant (NWQ), and to provide capacity and redundancy for service elsewhere across the valley as well.

- Water meter replacements are estimated to cost $3,100,000 this year and will begin to allow meters to be read remotely. The meter replacement program is budgeted for $3,100,000 in years subsequent (through 2022-23). Upgrades are expected to reduce costs of meter reading and allow customers to access water consumption information in real time, thus supporting water conservation programs and enabling customers to identify property-side leakages promptly.

Improvements planned in the Sewer Utility have to do with updates and replacements to aging infrastructure, as well as expansions to service capacity. Some items of note:

- Approximately $6,380,000 in maintenance to the existing Water Reclamation Facility (WRF), along with $54,700,000 budgeted for initial construction and design related to the new WRF. As noted above, a total cost estimate for the new facility's construction approaches $528,130,000. The facility's construction is currently expected to be complete and operational in 2024 in order to meet a 2025 deadline based on federal and state nutrient discharge regulatory requirements. Issue periods of bonds used to fund the new construction are timed to coincide with the life of the WRF; payments on the bonds are timed to coincide with the customers who will most benefit during this 30-year period.
- Master Plan implementation of sanitary sewer system upgrades and expansions are budgeted for a combined total of $17,850,000 in the fiscal year 2020, and are budgeted for $19,500,000 and $17,000,000 in the two subsequent fiscal years, respectively. These projects will provide for needed capacity in areas where capacity is already an issue, particularly on the fast-growing west side of the City.
- Ongoing remediation for the Northwest Oil Drain Canal near the WRF will incur estimated costs of $150,000 (the budgeted $300,000 for last year was not spent) in the Sewer Utility.

The following are some items of note planned as part of the Stormwater Utility's capital improvements program for the fiscal year 2018-19.

- Collection mains upgrades on 1700 South from 2100 East to its intersection with Emigration Creek are budgeted for $1,100,000 in fiscal 2020 and another $1,100,000 in the following fiscal year. This is to address stormwater capacity on 1700 South during intense runoff, such as the summer rain events experienced in 2017. $211,811 had been expended for this project during fiscal 2019 at the time of the proposed budget's preparation.
- Updates to stormwater-related infrastructure on Gladiola Street from 500 South to 900 South will total an estimated $869,550; updates to storm drain infrastructure along 1300 East are budgeted for an estimated $1,200,00o during fiscal 2020; expenditures on the stormwater portion of this project during fiscal 2019 totaled $377,165.
- Water quality and riparian corridor improvements related to updates at the Stormwater Utility's 1000 North Lift Station are budgeted for $1,700,000; $88,652 was expended during fiscal 2019. This is a projected budget increase of about $700,000 for the project.
- Contributions by developers related to local area projects in the Stormwater Utility are expected to total $400,000. These can be in the form of property or other assets, as well.
- An update to the Drainage Master Plan is budgeted for $700,000. The existing Plan was completed in 1993 and outlines a number of upgrades to the Utility's infrastructure that have taken place since. A new look at the Plan will involve changing climate conditions and green infrastructure.

The Street Lighting Utility will:

- implement a program to provide matching grants for residents interested in certain kinds of privately-maintained lights. The grant is funded by an annual transfer of $20,000 from the General Fund.
- Other capital improvements in the Street Lighting Utility for the fiscal year 2020 are budgeted for $1,725,000 (down from an estimated $2,605,000 last year).
- 8,398 of the 15,662 lights the City maintains are now considered to be energy efficient; Street Lighting is in the seventh year of a ten-year plan to convert all the lights to "high energy efficiency lamps."
- Furthermore, $90,000 is budgeted for the ongoing Street Lighting Master Plan update this year.

Personnel-related increases:
The Department of Public Utilities has historically been conservative with personnel additions; for example, staff adjustments for a sample previous three fiscal years totaled 2 seasonal watershed-related additions, 2 new positions for sewer collection, and one new accountant position.

Proposed staff adjustments will allow the Utilities to manage capital projects, account for increased operational and regulatory needs, and provide succession for key positions. This year's additions total 17 new FTEs, expected to be distributed across the Utilities as follows (charts on next page).

Proposed Personnel Adjustments FY 2019- 2020

Administration	Water	Sewer	Stormwater	Street Lighting	Total
Engineering Technician I	-	-	-	1.00	1.00
Records Technician	0.80	0.10	0.10	-	1.00
Engineer II	0.50	0.25	0.25	-	1.00
Community & Engagement Coordinator	0.50	0.40	0.10	-	1.00
Sustainability Program Manager	1.00	-	-	-	1.00
					5.00
Water Reclamation Facility					
Pretreatment Inspector/Permit Writer		1.00			1.00
Pretreatment Senior Sampler/Inspector		1.00			1.00
FOG/Sewer Rate Program Supervisor		1.00			1.00
Office Technician II		1.00			1.00
					4.00
Maintenance					
Senior Water System Maintenance Worker	1.00				1.00
					1.00
GIS					
GIS Leak Detector II	0.50	0.30	0.20		1.00
					1.00
Engineering					
Engineering Technician II	1.00	0.50	0.50		2.00
Engineering Technician III	0.50	0.25	0.25		1.00
Engineer III	1.00	0.50	0.50		2.00
					5.00
Seasonal Positions					
Watershed Worker (2)	1.00				1.00
					1.00
Total New FTEs	**7.80**	**6.30**	**1.90**	**1.00**	**17.00**

Proposed Personnel Adjustments FY 2018/19

NEW JOBS REQUESTED FOR FY 18/19	Total FTEs	WATER	SEWER	STORM WATER	STREET LIGHTING
Prior Year 2018 Beginning Balance	**408.50**	**262.53**	**112.43**	**31.12**	**2.42**
1) PROJECT CONTROL SPECIALIST	1.00	0.50	0.38	0.10	0.02
2) DOCUMENT CONTROLS SPECIALIST	1.00	0.50	0.38	0.10	0.02
3) ENGINEERING TECHNICIAN III	1.00	0.50	0.38	0.10	0.02
4) ENGINNERING TECHNICIAN III	1.00	0.50	0.38	0.10	0.02
5) WATER RIGHTS ASSISTANT	1.00	0.50	0.25	0.25	
6) WATERSHED RANGER	1.00	1.00			
7) WATER PLANT OPERATOR II	1.00	1.00			
8) STORMWATER COMPLIANCE SPECIALIST	1.00			1.00	
9) STORMWATER TECHNICIAN	1.00			1.00	
10) PRETREATMENT INSPEC / PERMIT WRITER	1.00		1.00		
11) SENIOR WATER SYSTEM MAINTENANCE LEAD	1.00	1.00			
12) WATER SYSTEM MAINTENANCE OPERATOR II	1.00	1.00			
13) WATER SYSTEM MAINTENANCE OPERATOR I	1.00	1.00			
14) OFFICE FACILITATOR I - SHOPS PAYROLL (REPLACING VACATED BY HR)	1.00	0.74	0.18	0.08	
TOTAL NEW FTE'S	14.00	8.24	2.95	2.73	0.08
CHANGES DUE TO PAY REDISTRIBUTION:	1.00	2.00	0.05	-1.05	-1.00
TOTAL CHANGES TO FTE'S	14.00	10.24	3.00	1.68	-0.92
	33				
Projected Agency Total FTEs for 2019	**422.50**	**272.77**	**115.43**	**32.80**	**1.50**

OTHER BACKGROUND

Role of Impact Fees in upcoming major capital projects:
Related to this discussion of infrastructure improvements and betterments is the concept of impact fees. Impact fees are assessed and paid to the municipality by developing entities. They in turn go to pay for only the expansion, or “growth” component of what is required to provide a level of service, without going to pay for improving or otherwise modifying the existing level of service.

- In the Water Reclamation Facility (WRF):
  Impact fees cannot be used to help entities like the City’s Sewer Utility meet regulatory requirements. They cannot be used to pay for maintenance and operations of existing services, either. For example, the City’s construction of a new WRF is not expected to expand the current level of service, but is necessary to meet updated regulatory requirements and to replace aging and deteriorated infrastructure. The old plant is not operating at or beyond capacity, so the new plant is not a response to a need to expand capacity; the new plant is thus not considered eligible for funding through impact fees. However, the new plant is being constructed in such a way that expansions could be integrated. If these expansions of the facility were implemented to respond to an increased need for service capacity, construction of the expansions could be eligible for funding through impact fees at some time in the future. This is being more carefully evaluated in the Department’s updated Impact Fee Facilities Plan (IFFP).

  In addition to the Sewer Utility, the Water Utility has many such related expenses budgeted for the fiscal year 2020. The need for these capital improvements results from the need to update and replace aging infrastructure, and where this is the only impetus for the improvements, the projects will not be eligible for funding through impact fees. However, some conveyance projects such as the east-west aqueduct funded for a total $20 million in fiscal years 2020 and 2021 are expected to be eligible for impact fees because of directly accommodating an expanded need for service, especially with regard to new development in the Northwest Quadrant. The updated IFFP will identify the portion of Water Utility projects that are reasonably apportioned to growth.

  Capital improvements aside from the WRF in the Sewer Utility deal mostly with collection line system and capacity improvements on the City’s west-side, near the site of the current and future WRF. The Department of Public Utilities staff reports these Master Plan collection line system improvements are necessary to maintain the existing level of service and are in response to anticipated deterioration, again commensurate with aging infrastructure. Some of these projects will also increase capacity to accommodate growth. Where some of these projects are being placed on an accelerated timeline, funding such as the State no-interest loan, has been applied to ease the burden for ratepayers. Again, where maintenance or new regulation would be the only impetus for the projects, impact fees do not apply. However, some of the upgrades are expected to be eligible for funding through impact fees; specifics as to which in particular are pending at the time of this writing and will be incorporated in the Department’s work updating the IFFP.

- In the new State Prison:
  Commensurate with the impact fee model, developing entities are expected to pay the City’s Utilities for connections. For example, when a new apartment building is constructed, the developing entity would need to compensate the City at a certain predetermined rate for the number of Utilities-related facilities the development would provide (faucets, toilets, drains). However, the State as the developing entity responsible for implementation of the new Prison is not understood to be liable for providing these fees for connection. This is another aspect of how the State’s arrangement with the municipality is different from other situations.

Department of Public Utilities responses to Council staff email questions, April 2019

Service Level

There are no reductions in service for Public Utilities. In fact, service level is increasing for each of the utilities due to a number of factors, including:

1) Growth throughout the service area causing the need for increased development review, inspections, and engineering

2) The need to address aging water and sewer infrastructure

3) Additional regulatory requirements related to drinking water, stormwater, and sewer

4) The need for updated long term plans for each of the four utilities due to growth, climate change, and public values

5) The need for increased public engagement as we address the above issues

Changes in Programs or Projects from Last Year

Programming and project work continues at a similar level compared to the last fiscal year. There are some increases in programming and projects, including:

1) Design and construction of the new sewer treatment plant

2) Continued capital asset planning for critical infrastructure

3) Increases in stormwater programming and standard operating procedures as a result of managing the City's overall stormwater permit with UDEQ, and as a result of an audit conducted by UDEQ and USEPA in 2016

4) Development of a Fats Oils and Grease (FOG) program for the sewer utility

5) New state reporting requirements related to water use, water rights, and water source sizing

6) New vulnerability and emergency management requirements pursuant to the America's Water Infrastructure Act (passed October 2018)

7) New federal and state requirements anticipated this year regarding emerging contaminants

8) Expedited sewer, water, and stormwater pipe replacements to support the City's general obligation bond for roadway reconstruction

Vacant Positions

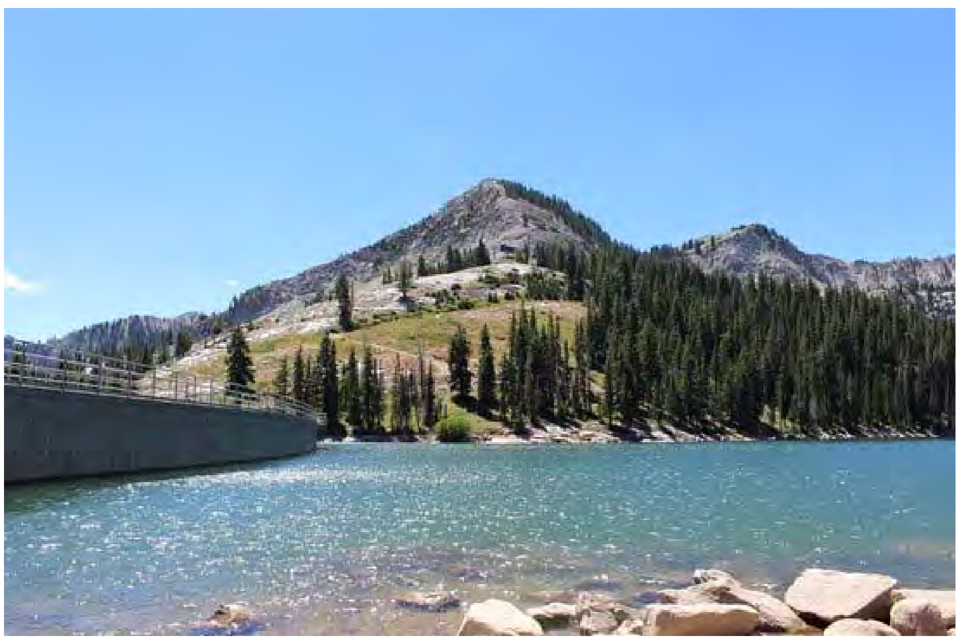
As of April 3, 2019, Public Utilities had a total of 24 vacant positions out of 422 positions. Of this total, the Water Utility has 16.5 FTE's, Sewer 6.5 FTE's, and Stormwater 1.0 FTE. The department intends to fill all vacancies, and the hiring process is ongoing.

Carbon Reductions

The Public Utilities budget for FY20 includes an appendix regarding the department's energy management and greenhouse gas mitigation projects. (See Appendix C of proposed budget document and Attachment 5).

PUBLIC UTILTIES ANNUAL
2019-20 FISCAL BUDGET PROPOSAL

Public Utilities



April 3, 2019

WATER.— SEWER — STORMWATER — STREET LIGHTING

ENTERPRISE FUNDS

"Serving our Community, Protecting our Environment

SALT LAKE CITY DEPARTMENT OF PUBLIC UTILITIES
RECOMMENDED BUDGET FOR FISCAL YEAR 2020

Salt Lake City Department of Public Utilities

I recommend for approval, rates, operations, personnel changes and the capital program as herein presented as the Salt Lake City Department of Public Utilities FY2020 Proposed Budget:

Laura Briefer, Director________________________

Public Utilities Advisory Committee (PUAC)

The PUAC concurs with and supports the Salt Lake City Department of Public Utilities FY2020 Proposed Budget presentation:

Ted Wilson, Chair________________________

Dated March 28, 2019

Table of Contents

Executive Summary FY 2020

Salt Lake City Department of Public Utilities (Department) is pleased to present its recommended budget for fiscal year 2019-2020 (FY2020). In addition to ongoing operations, the budget as presented includes funding for capital projects in the Water, Sewer, Stormwater, and Street Lighting Utilities to upgrade infrastructure, comply with regulations, and support growth.

As in previous years, a major focus of the Department's budget is in the rehabilitation and replacement of aging infrastructure. The Department has implemented a rigorous capital asset program that assesses the condition and criticality of water infrastructure. This proactive approach mitigates the risk of future failures of water, sewer, and stormwater infrastructure. Infrastructure failure and degradation can lead to public health, water supply, and environmental impacts. The largest planned projects are components of the new Water Reclamation Facility (WRF) that will be completed by 2024, improvements to the Big Cottonwood Water Treatment Plant, construction of a new water transmission line to serve downtown Salt Lake City, conceptual design for a new Public Utilities campus, and Water, Sewer, and Stormwater Utility infrastructure work necessitated by street improvements projects pursuant to the City's passage of a general obligation bond for that purpose.

Funding for capital projects in FY2020 will be generated through the issuance of revenue bonds and rate increases. Total bonding planned for FY2020 is $105,084,000. Proposed rate increases are 5% in the Water Utility, 18% in the Sewer Utility, and 10% in the Stormwater Utility. Street Lighting rates will remain the same. For future years, the Department is investigating the use of a federal low interest loan program for utility infrastructure as an additional funding source.

Summary of Utilities Fund Budgets

Utility Funds FY 2020	Operations	Capital	Debt	Fund Totals
Water	66,275,770	61,764,547	1,781,000	129,821,317
Sewer	21,024,164	107,064,500	13,456,000	141,544,664
Storm	7,172,368	13,472,149	1,306,000	21,950,517
Street	2,963,277	1,725,000	103,000	4,791,277
Total	$ 97,435,579	$ 184,026,196	$ 16,646,000	$ 298,107,775

The proposed budget includes the implementation of the structural rate changes to water and sewer rates pursuant to the Department's 2018 Comprehensive Water, Sewer and Stormwater Rate Study, and as presented to the Mayor and City Council. A proposed resolution adopting these structural changes is presented in Appendix A. As part of environmental regulatory requirements, the Utah Department of Environmental Quality is also requiring a City resolution approving the new WRF, which is also included in Appendix A.

The proposed budget includes the addition of 17 new full time equivalent (FTE) positions. These recommended positions are identified to assist the Department in meeting environmental requirements, implementing capital projects, and responding to economic and geographic growth within our service areas. The Department is also proposing two minor organizational structure changes to provide for succession planning and increased efficiency. Specific rationale is provided for these positions in Appendix B of this document.

As part of Mayor Biskupski's energy and climate initiative, the Department was requested to identify projects within the FY2020 Budget that demonstrate reductions in energy use through efficiency and/or renewable energy projects. Appendix C of this document summarizes the Department's Energy Management and Greenhouse Mitigation Projects and highlights several capital projects in each of the Department's four utilities that demonstrate energy and greenhouse gas reductions.

Budget Summary

The total proposed Department budget is $298,107,775, a 2.00% increase from the FY2019 amended budget of $292,268,301. The adopted budget was adjusted for FY2018 carryover encumbrances for open contracts and purchase orders. Those changes are reflected in the amended budget amount. The proposed operating budget of $97,435,579 is $2,054,167 or 2.15% higher than the current year. The increase includes the proposed new FTEs, a 3% cost of living adjustment (COLA) and a 7% increase in health insurance premiums. This also reflects a 3% rate increase for water purchased from the Metropolitan Water District of Salt Lake and Sandy (MWDSLS).

The proposed capital budget for FY2020 is $184,026,196. Debt service is anticipated to be $16,646,000, including the cost of issuing new debt during the year. Total debt service for FY2020 is increasing due to the cost of issuing new debt and the payment of the initial installment due on a state loan.

Proposed Department of Public Utilities Expenditures for FY 2019-20

Major Expenditure Categories	Adopted Budget 2018-2019	Amended Budget 2018-2019	Proposed Budget 2019-2020	Difference	Percent Change
Personal Services	35,516,006	35,516,006	38,021,063	2,505,057	7.05%
Materials and Supplies	6,346,750	6,362,247	6,733,060	370,813	5.83%
Charges for Services	49,321,529	53,503,159	52,681,456	(821,703)	-1.54%
Debt Service	8,317,000	8,317,000	16,646,000	8,329,000	100.14%
Capital Outlay	11,076,468	11,144,372	11,931,596	787,224	7.06%
Capital Improvements	123,721,000	177,425,517	172,094,600	(5,330,917)	-3.00%
Total	**$ 234,298,753**	**$ 292,268,301**	**$ 298,107,775**	**$ 5,839,474**	**2.00%**

The proposed budget includes projects rated as high priority in the Department's Capital Asset Program (CAP). The major capital improvement projects categories in the FY2020 budget are included in each Utility's budget description in the following sections. A detailed list of capital improvement projects is included in the cash flow summaries for each utility.

The Department's total anticipated revenues for FY2020 are $249,137,157, an increase of $109,630,160. Proposed rate increases are expected to generate $10,138,168 and the issuance of $105,084,000 in bonds account for the remaining increase. The Department intends to balance the budget utilizing $48,970,618 of reserves in all Utility funds. The reserves include the remaining balance of approximately $30 million from the 2017 bond issue.

Projected Department of Public Utilities Revenues for FY 2019-20

Revenue	Adopted Budget 2018-2019	Amended Budget 2018-2019	Proposed Budget 2019-2020	Difference	Percent Change
Operating Sales	123,992,012	123,992,012	134,130,180	10,138,168	8.18%
Interest	1,512,000	1,512,000	883,820	(628,180)	-41.55%
Permits	70,000	70,000	70,000	-	0.00%
Interfund Charges	2,449,985	2,449,985	2,475,157	25,172	1.03%
Other Revenues	833,000	833,000	833,000	-	0.00%
Impact Fees	1,400,000	1,400,000	1,900,000	500,000	35.71%
Contributions	3,895,000	3,895,000	3,761,000	(134,000)	-3.44%
Bond Proceeds	5,355,000	5,355,000	105,084,000	99,729,000	1862.35%
From (To) Reserves	94,791,756	152,761,304	48,970,618	(103,790,686)	-67.94%
Total	**$ 234,298,753**	**$ 292,268,301**	**$ 298,107,775**	**$ 5,839,474**	**2.00%**

Department revenues are generally predictable for all funds except water which is based on changes in seasonal use due to weather during the summer. A cooler, wetter summer and spring will reduce water demand and sales. The Department's water conservation rate structure and conservation education have and continue to be effective as customer's sensitivity to water usage has been proactive. The current water availability and storage reservoirs will have adequate coverage FY 2020, therefore water revenues are forecast on a normal or average expected usage.

Summary of Additional Proposed Positions

The Department currently has 422.50 FTEs and is proposing the following positions to meet identified needs. The Department is proposing adding 17 FTEs as shown in the following chart. A detailed description of these positions is provided in Appendix B.

Proposed Personnel Adjustments FY 2019- 2020

Administration	Water	Sewer	Stormwater	Street Lighting	Total
Engineering Technician I	-	-	-	1.00	1.00
Records Technician	0.80	0.10	0.10	-	1.00
Engineer II	0.50	0.25	0.25	-	1.00
Community & Engagement Coordinator	0.50	0.40	0.10	-	1.00
Sustainability Program Manager	1.00	-	-	-	1.00
					5.00
Water Reclamation Facility					
Pretreatment Inspector/Permit Writer		1.00			1.00
Pretreatment Senior Sampler/Inspector		1.00			1.00
FOG/Sewer Rate Program Supervisor		1.00			1.00
Office Technician II		1.00			1.00
					4.00
Maintenance					
Senior Water System Maintenance Worker	1.00				1.00
					1.00
GIS					
GIS Leak Detector II	0.50	0.30	0.20		1.00
					1.00
Engineering					
Engineering Technician II	1.00	0.50	0.50		2.00
Engineering Technician III	0.50	0.25	0.25		1.00
Engineer III	1.00	0.50	0.50		2.00
					5.00
Seasonal Positions					
Watershed Worker (2)	1.00				1.00
					1.00
Total New FTEs	**7.80**	**6.30**	**1.90**	**1.00**	**17.00**

Water Utility Enterprise Fund

Water Infrastructure Background

The Salt Lake City water system is one of the oldest and largest systems west of the Mississippi River with over 1,125 miles of 12” or smaller distribution lines, and more than 180 miles of large transmission mains for a total asset inventory of 1,305 miles of pipe with over fifty pressure zones. The service area covers the Salt Lake City corporate boundaries as well as the east side of the Salt Lake Valley to the mouth of Little Cottonwood Canyon—a total of 134 square miles. This includes water supply to the newly incorporated Mill Creek City, as well as Cottonwood Heights, Holladay, and small portions of Murray, Midvale, and South Salt Lake Cities. The Department’s asset management program includes personnel and systems to assess the condition of the large water transmission mains, treatment and pumping plants, and other infrastructure to assure repair and replacement is completed with minimal impact to the public. Each of the Department’s three water treatment plants were originally constructed in the 1950’s and have undergone numerous upgrades. There is also a continual need to repair and replace pipe segments to maintain service and reduce emergency repair costs and impacts to the public.

Water Utility Budget Highlights for FY2020

Anticipated Revenues

A proposed 5% rate increase is anticipated to generate an additional $2,442,107. Proposed rates for FY2020 are impacted by two elements: 1) implementation of a rate structure and cost of service study that was finalized in October 2018 and 2) the proposed rate increase. The additional revenue is required for the water utility to meet its capital and operations objectives.

The Department plans to issue bonds during FY2020 with $35,196,000 designated for water. Additional bonding of $112,627,000 is anticipated from FY 2021 to FY2024 meet water utility capital project objectives.

The revenue budget is proposed to increase by $7,026,186 or 5.72% from the FY2019 budget. The proposed budget for FY2020 by major category is as follows:

Projected Water Revenues for FY 2019-20

Revenue	Adopted Budget 2018-2019	Amended Budget 2018-2019	Proposed Budget 2019-2020	Difference	Percent Change
Operating Sales	73,289,346	73,289,346	75,731,453	2,442,107	3.33%
Interest	375,000	375,000	229,000	(146,000)	-38.93%
Interfund Charges	2,449,985	2,449,985	2,475,157	25,172	1.03%
Other Revenues	638,000	638,000	638,000	-	0.00%
Impact Fees	500,000	500,000	1,000,000	500,000	100.00%
Contributions	1,205,000	1,205,000	1,205,000	-	0.00%
Bond Proceeds	-	-	35,196,000	35,196,000	
From (To) Reserves	25,735,446	44,337,800	13,346,707	(30,991,093)	-69.90%
Total	**$ 104,192,777**	**$ 122,795,131**	**$ 129,821,317**	**$ 7,026,186**	**5.72%**

Operating Sales: The implementation of the new rate structure combined with the 5% proposed rate increase is estimated to generate $2,442,107 or 3.33% more than the FY2019 budgeted amount. The implementation of both has no impact on the monthly billing for residential usage of 21 CCF

Interest Income: Interest earnings are expected to decrease as reserve funds are invested in capital improvements.

Interfund Charges: The Water Utility is reimbursed by Sewer, Stormwater, Street Lighting, Refuse, and the Hive program for services related to billing. Related revenue is not expected to change significantly.

Impact Fees: Impact fees are budgeted to increase $500,000 for new development. The FY2020 budget is a conservative estimate based on the historical average.

Bond Proceeds: A bond issue of $35,196,000 million is anticipated.

Reserve Funds: The Department plans to use $13,346,707 of reserve funds to balance the capital and operational needs. Budgeted use of reserve funds is <$30,991,093> less than the FY2019 amended budget or a decrease of <69.90%>.

Proposed Expenditures

The Water Utility's FY2020 budget includes a decrease of <$1,182,293> in other professional and technical services which is off-set by a $1,317,556 increase in personal services. The increase in personal services is attributed to the addition of 7.80 FTEs, a 3% COLA for employees, and a 7% increase in health insurance costs. The new FTEs requested will support the Department's water quality, engineering, water operations, and administration service offerings to benefit residents of the Water Utility's water service area.

The Department expects a $479,845 or 3% increase in the price of water from Metropolitan District of Salt Lake and Sandy for FY2020.

The Department plans to invest $59,255,100 in capital improvements for Water Utility infrastructure in FY2020. The capital improvement program includes a prioritized balance of needed improvements to treatment plants, water lines, meter replacements, pump stations, wells, and other infrastructure.

The schedule for some water main replacements has been accelerated to perform work in conjunction with the General Fund bonded street repair projects. The FY 2020 capital improvements budget includes $9,650,000 for these replacements. Future years anticipate an additional $17,890,000 in projects related to the proposed street related projects that are part of the 2018 general obligation bond for streets. The water main budget also includes the $10,000,000 for the East West Conveyance Line.

The expenditure budget for the Water Utility is proposed to increase $7,026,186 or 5.72% from the FY2019 budget. The proposed budget for FY2020 by major category is as follows:

Proposed Water Expenditures for FY 2019-20

Major Expenditure Categories	Adopted Budget 2018-2019	Amended Budget 2018-2019	Proposed Budget 2019-2020	Difference	Percent Change
Personal Services	22,069,746	22,069,746	23,387,302	1,317,556	5.97%
Materials and Supplies	4,218,280	4,233,777	4,415,380	181,603	4.29%
Charges for Services	36,600,851	39,051,011	38,473,088	(577,923)	-1.48%
Debt Service	1,117,000	1,117,000	1,781,000	664,000	59.44%
Capital Outlay	4,614,400	4,682,304	2,509,447	(2,172,857)	-46.41%
Capital Improvements	35,572,500	51,641,293	59,255,100	7,613,807	14.74%
Total	**$ 104,192,777**	**$ 122,795,131**	**$ 129,821,317**	**$ 7,026,186**	**5.72%**

Personal Services: Employee related costs are estimated to increase $1,317,556 or 5.97%. The water utility budget anticipates an increase of 7.80 FTEs. The FY2020 budget includes a 3% COLA and a 7% increase in costs of health insurance.

Materials & Supplies: The increase of $181,603 is driven by a $110,000 increase in sand and gravel as well as increases in grounds and building supplies and computer supplies. Small tools and equipment decreased from last year.

Charges for Services: The proposed budget for charges and services will decrease <$577,923> or <1.63%>. The decrease can be attributed to a <$1,182,293>decrease in outsourced technical services and a <$111,000> decrease in payment in lieu of taxes that are offset by the price increase for water purchases from Metropolitan Water District.

Debt Service: - In compliance with the Series 2017 Refunding Bond, and in anticipation of a Series 2020—3.9%, 30 Year—Bond, the budget for debt service increased by $664,000.

Capital Outlay: The proposed budget for capital outlay for FY2020 includes $1,500,000 for watershed purchases, $30,000 for water rights, $494,265 for 14 vehicles, $175,182 for field equipment, $50,000 for pumping equipment, $60,000 for treatment plant equipment, $50,000 for telemetry, $30,000 for office furniture & equipment, and $120,000 for other non-motive equipment.

Capital Improvements: The Water proposed CIP budget for FY2020 is $59,255,100. A detailed list of CIP projects is included in the cash flow summaries for the Water Utility. A capital project summary by facility type is as follows:

Proposed Water Capital Improvement Program for FY 2019-20

Type of Project	Proposed Budget 2019-2020
Treatment Plants	7,850,000
Water Service Connections	5,900,000
Pumping Plant Upgrades	1,565,000
Reservoirs	3,435,000
Water Mains and Hydrants	35,530,100
Wells	3,400,000
Culverts, Flumes, and Bridges	1,455,000
Watershed	120,000
Total 2019-2020 CIP	**$ 59,255,100**

Sewer Utility Enterprise Fund

Sewer Infrastructure Background

The City's Water Reclamation Facility (WRF) was constructed in 1965 and has undergone numerous upgrades since. Nutrient removal regulations adopted by the Utah Department of Environmental Quality (UDEQ) in 2015 require a new sewage treatment process. After much study, the Department determined that the WRF has reached the end of its useful life and adapting the 54 year old facility to meet the new nutrient removal requirements is not feasible. A new WRF is currently under design, to be completed by 2024 in order to meet UDEQ's nutrient compliance date of January 1, 2025. The Department has been implementing gradual rate increases and revenue bonding for the replacement of the WRF.

The sewer collection system (654 miles of pipeline, and several pump stations in 2018) is a very challenging environment; hydrogen sulfide gases, sediment, roots and other factors affect the competency of the collection lines. The Department's asset management program includes personnel and systems to assess the condition of the large water transmission mains, treatment and pumping plants, and other infrastructure to assure repair and replacement is completed with minimal impact to the public. More than 50% of the sewer collection system is greater than 85 years old.

The Department is expanding portions of the sewer collection system, in large part to meet growth requirements related to the new State Correctional Facility, the Airport expansion, and new development anticipated in the Northwest Quadrant of Salt Lake City.

Sewer Utility Budget Highlights for FY2020

Total project costs for the WRF reconstruction are anticipated to be $528,130,000 when the project is completed. Construction will begin in FY2020. Public Utilities has expended approximately $6 million over the last several years in preparation for this project.

Current financing for the new WRF is anticipated to be accomplished using a combination of revenue bonds and user rates. The Department plans to submit a letter of interest in spring 2019 for consideration to apply for federal loans pursuant to the Water Infrastructure Finance and Innovation Act (WIFIA). If invited to apply, the program loan would provide up to 49% of the cost of the new WRF. The interest rate is locked in at loan closing and repayment schedules can be structured to complement revenue bond debt payments. If a loan is not approved, the project costs will be funded through revenue bonds. The two scenarios are as follows:

Scenario 1: Sewer Planned Debt

FY	WIFIA	Bonds	Total
2019-2020	-	55,000,000	55,000,000
2020-2021	67,429,000	51,450,000	118,879,000
2021-2022	85,926,000	59,180,000	145,106,000
2022-2023	65,057,000	62,230,000	127,287,000
2023-2024	31,865,000	27,440,000	59,305,000
Total	**$ 250,277,000**	**$ 255,300,000**	**$ 505,577,000**

Scenario 2: Sewer Planned Debt

FY	Bonds
2019-2020	55,000,000
2020-2021	107,000,000
2021-2022	187,000,000
2022-2023	138,000,000
2023-2024	69,000,000
Total	**$ 556,000,000**

Anticipated Revenues

A proposed 18% rate increase is anticipated to generate an additional $6,782,334 in sewer fees. Proposed rates for FY2020 are impacted by two elements: 1) implementation of a rate and cost of service study that was finalized in October 2018; and 2) the proposed rate increase. The additional revenue is required for the Sewer Utility to meet its capital and operations objectives. Rate increases in future years are also anticipated at this time. The rate increases are anticipated to vary based on the source of debt.

Forecast Rate Increases

FY	WIFIA/Bonds	Bonds	Difference
2019-2020	18%	18%	0%
2020-2021	18%	20%	-2%
2021-2022	18%	25%	-7%
2022-2023	15%	25%	-10%
2023-2024	10%	10%	0%
Average	**16%**	**20%**	**-4%**

The Department plans to issue bonds during FY2020 with $55,307,000 designated for the Sewer Utility. Additional debt of $471,287,000 is anticipated from FY2021 to FY2024 to meet Sewer Utility capital objectives, primarily the reconstruction of the WRF. Debt will be used in conjunction with rate increases to blend pay as you go and borrowing strategies. The proposed debt is for a 30 year term creating intergenerational equity payback on the new WRF facility. The process will engage the City's professional advisors to measure debt service and ratios to comply with external rating agency standards. The Department intends to maintain its AAA rating to limit costs of borrowing.

The total revenue budget is expected to decrease by <$6,540,494> or <4.42%> to $141,544,664 from the FY2019 amended budget. A reduction in the budgeted use of reserve funds is driving the decrease. The proposed budget for FY2020 by major category is as follows:

Projected Sewer Revenues for FY 2019-20

Revenue	Adopted Budget 2018-2019	Amended Budget 2018-2019	Proposed Budget 2019-2020	Difference	Percent Change
Operating Sales	37,677,666	37,677,666	44,460,000	6,782,334	18.00%
Interest	1,052,000	1,052,000	604,000	(448,000)	-42.59%
Permits	70,000	70,000	70,000	-	
Other Revenues	185,000	185,000	185,000	-	0.00%
Bond/ Note Proceeds	4,000,000	4,000,000	55,307,000	51,307,000	1282.68%
Impact Fees	700,000	700,000	700,000	-	0.00%
Contribution	2,020,000	2,020,000	2,020,000	-	
From (To) Reserves	65,246,893	102,380,492	38,198,664	(64,181,828)	-62.69%
Total	**$ 110,951,559**	**$ 148,085,158**	**$ 141,544,664**	**$ (6,540,494)**	**-4.42%**

<u>Sewer service fees</u>: Sewer service fees are expected to increase $6,782,334 or 18%. The proposed rate increase is approximately $5.04 per month for the representative resident (assuming winter water use of eight CCF). The increase reflects the implementation of the new rate structure and the 18% rate increase. The additional revenue is required for the sewer utility to meet its capital and operations objectives

<u>Interest Income</u>: Interest earnings are expected to decrease as reserve funds and remaining bond proceeds are invested in capital improvements.

<u>Bond / Note Proceeds:</u> A bond issue of $55,307,000 is anticipated.

<u>Reserve Funds</u>: Reserve funds of $38,198,664, including funds from the 2017 Bond issue, will balance the Sewer Utility's capital and operational needs with FY2020 revenue. Budgeted use of reserve funds decreases <$64,181,828> from the FY2019 budget.

<u>Proposed Expenditures</u>

The proposed sewer budget for FY2020 includes $98,370,500 in planned projects. Of this amount $54,700,000 is planned for the new WRF facility, $6,380,000 for the existing plant, and $36,630,500 for improvements to the sewer collections system. The schedule for some sewer collection line replacements has been accelerated to perform work in conjunction

with the City's general obligation bonded street repair projects. The FY2020 capital improvements budget includes $4,850,000 for these replacements. Future years anticipate an additional $21,200,000 to support the general obligation of the bonded street related projects.

The Sewer Utility's FY 2020 budget proposes a decrease of <$6,540,494> or <4.42%> from the FY2019 amended budget. The proposed budget for FY2020 by major category is as follows:

Proposed Sewer Expenditures for FY 2019-20

Major Expenditure Categories	Adopted Budget 2018-2019	Amended Budget 2018-2019	Proposed Budget 2019-2020	Difference	Percent Change
Personal Services	10,375,345	10,375,345	11,164,232	788,887	7.60%
Materials and Supplies	1,934,720	1,934,720	2,109,430	174,710	9.03%
Charges for Services	6,211,994	7,115,552	7,750,502	634,950	8.92%
Debt Service	6,073,000	6,073,000	13,456,000	7,383,000	121.57%
Capital Outlay	5,946,500	5,946,500	8,694,000	2,747,500	46.20%
Capital Improvements	80,410,000	116,640,041	98,370,500	(18,269,541)	-15.66%
Total	**$ 110,951,559**	**$ 148,085,158**	**$ 141,544,664**	**$ (6,540,494)**	**-4.42%**

Personal Services: Employee related costs are estimated to increase $788,887 or 7.60%. The sewer utility budget anticipates an increase of 6.30 FTEs. The FY2020 budget includes a 3% COLA and a 7% increase in costs of health insurance.

Materials & Supplies: The Sewer Utility's budget for this category increased by $174,710. This increase is attributed to laboratory supplies, chemicals, and small tools and equipment:

Charges for Services: The budget for charges and services increased by $634,950. The most significant items in this category are an increase in data processing services of $113,000 and a $293,013 increase in payment in lieu of taxes.

Debt Service: - The annual debt service budget is expected to increase by $7,383,000 in FY2020. A payment of $6,375,000 on a note payable is required during the year. The remaining increase is in accordance with existing debt service schedules and planned bond issues.

Capital Outlay: - The proposed capital outlay budget for FY2020 includes $5,600,000 for land, $1,717,500 for a vehicles and trucks, $408,000 for field maintenance equipment, $778,500 treatment plant equipment, $10,000 for telemetry, $20,000 for office furniture and equipment, and $160,000 for other non-motive equipment.

Capital Improvements: The Sewer proposed CIP budget for FY2020 is $98,370,500, a decrease of <$18,269,541> from the current year amended budget. A detailed list of capital improvement projects is included in the cash flow summary for the Sewer Utility. A capital project summary by facility type is as follows:

Proposed Sewer Capital Improvement Program for FY 2019-20

Type of Project	Proposed Budget 2019-2020
WRF	61,080,000
Collection System	36,630,500
Lift Stations	510,000
Northwest Oil Drain	150,000
Total 2019-2020 CIP	**$ 98,370,500**

Stormwater Utility Enterprise Fund

Stormwater Infrastructure Background

The Drainage Master Plan was completed in 1993. The FY2020 budget includes an update of the Drainage Master Plan to address water quality and climate change issues, such as storm intensification. The projects identified in the Master Plan provide direction and areas that may or have already been completed. In the last ten years 34.4 miles of storm drain pipe has been installed.

Stormwater Utility Budget Highlights for FY2020

Anticipated Revenues

A proposed 10% rate increase or approximately $0.49 per equivalent residential unit (ERU) per month is included in the budget. Dwindling cash reserves, stronger regulatory requirements and infrastructure needs are drivers for the proposed rate increase. Additional rate increases between 10% and 6% are projected through FY2023.

The Department plans to issue bonds during FY2020 with $14,581,000 designated for stormwater utility needs. Additional bonding is planned in FY 2022.

The revenue budget is proposed to increase by $6,228,860 or 39.62% from the FY2019 budget. The proposed revenue budget for FY2020 by major category is as follows:

Projected Storm Revenues for FY 2019-20

Revenue	Adopted Budget 2018-2019	Amended Budget 2018-2019	Proposed Budget 2019-2020	Difference	Percent Change
Operating Sales	8,855,000	8,855,000	9,740,500	885,500	10.00%
Interest	33,000	33,000	20,820	(12,180)	-36.91%
Other Revenues	200,000	200,000	200,000	-	0.00%
Impact Fees	650,000	650,000	516,000	(134,000)	-20.62%
Contributions	1,000	1,000	1,000	-	0.00%
Bond Proceeds	1,355,000	1,355,000	14,581,000	13,226,000	
From (To) Reserves	2,492,300	4,627,657	(3,108,803)	(7,736,460)	-167.18%
Total	**$ 13,586,300**	**$ 15,721,657**	**$ 21,950,517**	**$ 6,228,860**	39.62%

Operating Sales: A rate increase of 10% or about $0.49 per ERU per month is estimated to generate $885,500 more than the current budget.

Interest Income: Interest earnings are expected to decrease as reserve funds are invested in capital improvements.

Contributions by Developers: Decrease of <$134,000> related to reimbursed cost sharing from oil companies related to Northwest Oil Drain remediation.

Bond / Note Proceeds: A bond issue of $14,581,000 is anticipated.

Reserve Funds: Unspent bond proceeds of $3,108,803 will be added to reserves for use on stormwater system improvements

Proposed Expenditures

The Stormwater Utility's FY2020 budget proposes capitalizing $12,744,000 to renovate portions of the stormwater collection system. The schedule for stormwater system improvements has been accelerated to perform work in conjunction with the general obligation bonded street repair projects. The FY2020 capital improvements budget includes $3,550,000 for these. Future years anticipate an additional $14,725,000 in the bonded street related projects. These capital items will be funded through rate increases and revenue bonds.

The expenditure budget for the Stormwater Utility is proposed to increase $6,228,860 or 39.62% from the current year FY2019 budget. The proposed budget for fiscal year FY2020 by major category is as follows:

Proposed Storm Expenditures for FY 2019-20

Major Expenditure Categories	Adopted Budget 2018-2019	Amended Budget 2018-2019	Proposed Budget 2019-2020	Difference	Percent Change
Personal Services	2,872,608	2,872,608	3,187,954	315,346	10.98%
Materials and Supplies	186,450	186,450	200,950	14,500	7.78%
Charges for Services	3,854,174	4,600,262	3,783,464	(816,798)	-17.76%
Debt Service	1,024,000	1,024,000	1,306,000	282,000	27.54%
Capital Outlay	515,568	515,568	728,149	212,581	41.23%
Capital Improvements	5,133,500	6,522,769	12,744,000	6,221,231	95.38%
Total	**$ 13,586,300**	**$ 15,721,657**	**$ 21,950,517**	**$ 6,228,860**	**39.62%**

Personal Services: Employee related costs are estimated to increase $315,346 or 10.98%. The stormwater utility budget anticipates an increase of 1.90 FTEs. The FY2020 budget includes a 3% COLA and a 7% increase in costs of health insurance.

Charges for Services: The decrease in this category is driven by planned reductions of <$836,222> in professional and consulting services. This decrease is partially offset by an increase in planned data processing costs.

Debt Service: The budget increases by $282,000 or 27.54% in anticipation of a Series 2020—3.9%, 30 Year—Bond.

Capital Outlay: The proposed capital outlay budget for FY2020 includes $672,649 for vehicles and $56,000 for various categories of equipment.

Capital Improvements: The Stormwater proposed capital improvement budget for FY2020 is $12,744,000, an increase of $6,221,231 over the FY2019 budget. A detailed list of

capital improvement projects is provided in the cash flow summary for the Stormwater Utility. The capital project summary by facility types are as follows:

Proposed Storm Capital Improvement Program for FY 2019-20

Type of Project	Proposed Budget 2019-2020
Lines and Riparian Corridor Projects	12,530,000
Lift Stations	64,000
Northwest Oil Drain	150,000
Total 2019-2020 CIP	**$ 12,744,000**

Street Lighting Utility Enterprise Fund

Street Lighting Infrastructure Background

The responsibility for provision of street lighting throughout the city was transferred to the Department from the General Fund in 2013. The Department is currently updating the City's 2006 Street Lighting Master Plan in order to focus on community safety and aesthetic needs, particularly since updating lights and conversion of street lights to energy efficiency bulbs has changed the character of lighting in some neighborhoods.

Of the 15,662 lights that the City maintains, 8,398 lights or 54% are now considered to be energy efficient. We are in the seventh year of a ten-year plan to convert all the lights to high energy efficiency lamps. The FY2020 budget funds continuing conversion to high efficiency lights. Ongoing conversions are anticipated in some neighborhoods once the Street Lighting Master Plan is completed to provide better guidelines related to lighting color and intensity. The Street Lighting Utility is saving energy that has approximately $300,000 favorable effect on the FY2020 budget and a similar effect in future years. There have been and may still be energy saving rebates available as the conversion continues.

Street Lighting Utility Budget Highlights for FY2020

Anticipated Revenues

No rate changes are proposed in the FY2020 budget or forecast in the immediate future. The base lighting rates were established in 2013 at $3.73 per month for an average residential customer, or Equivalent Residential Unit (ERU), and are expected to remain unchanged for this fiscal year. Rates for enhanced tiers are Tier 1 $5.67, Tier 2 $15.94, and Tier 3 $43.82.

Continuation of the private lights program is proposed in the FY2020 budget. The program includes a $20,000 transfer from the General Fund and indicates the on-going desire of the City to provide a matching support to reduce the capital costs to neighborhoods installing private street lighting. Public Utilities administers this program.

The revenue budget is proposed to decrease by <$875,078> from the FY2019 budget. The proposed budget for FY2020 by major category is as follows:

Projected Street Revenues for FY 2019-20

Revenue	Adopted Budget 2018-2019	Amended Budget 2018-2019	Proposed Budget 2019-2020	Difference	Percent Change
Operating Sales	4,170,000	4,170,000	4,198,227	28,227	0.68%
Interest	52,000	52,000	30,000	(22,000)	-42.31%
Other Revenues	9,000	9,000	9,000	-	0.00%
General Fund Contributions	20,000	20,000	20,000	-	0.00%
From (To) Reserves	1,317,117	1,415,355	534,050	(881,305)	-62.27%
Total	**$ 5,568,117**	**$ 5,666,355**	**$ 4,791,277**	**$ (875,078)**	**-15.44%**

Operating Sales: Rate changes are not proposed thus this category is not expected to change significantly. The FY2020 budget is based on actual revenue sales from FY2018

Interest Income: Interest earnings are expected to decrease as reserve funds are utilized.

General Fund Contributions: No change. Public Utilities anticipates the general fund to continue contributing $20,000 for private light options in FY2020.

Reserve Funds: The FY2020 budget anticipates using $534,050 from the utility's reserve funds—mostly unspent bond proceeds from the 2017 bond issue.

Proposed Expenditures

Street Lighting capital improvements totaling $1,725,000 are planned in the FY2020 budget. The Street Lighting Capital Program focuses on high efficiency and system

upgrades in neighborhood, arterial and collector streets and includes $200,000 for lighting controls

The expenditure budget for the Street Lighting Utility is proposed to decrease <$875,078> or <15.44%> from the FY2019 amended budget. The proposed budget for FY2020 by major category is as follows:

Proposed Street Expenditures for FY 2019-20

Major Expenditure Categories	Adopted Budget 2018-2019	Amended Budget 2018-2019	Proposed Budget 2019-2020	Difference	Percent Change
Personal Services	198,307	198,307	281,575	83,268	41.99%
Materials and Supplies	7,300	7,300	7,300	-	0.00%
Charges for Services	2,654,510	2,736,334	2,674,402	(61,932)	-2.26%
Debt Service	103,000	103,000	103,000	-	0.00%
Capital Improvements	2,605,000	2,621,414	1,725,000	(896,414)	-34.20%
Total	**$ 5,568,117**	**$ 5,666,355**	**$ 4,791,277**	**$ (875,078)**	**-15.44%**

<u>Personal Services</u>: Employee related costs are estimated to increase $83,268 of 41.99%. The Street Lighting Utility budget anticipates an increase of 1 FTE. The FY2020 budget includes a 3% COLA and a 7% increase in costs of employee insurance premiums.

<u>Charges for Services</u>: The proposed budget for charges and services decreases <$61,932> or <2.26%> in FY2020 with a <$81,824> budgeted decrease in professional services off-set by an increase in budgeted power costs.

<u>Debt Service</u>: In compliance with the outstanding bond, Series 2017 Bond, budgeted debt service payments remain unchanged in FY2020.

<u>Capital Equipment</u>: No expenditures for capital equipment are planned.

Capital Improvements: The proposed Street Lighting CIP budget for FY2020 is $1,725,0000, a decrease of <$896,414> from the FY2019 amended budget. A capital projects summary by facility type is as follows for base lighting and all enhanced tiers:

Proposed Street Capital Improvement Program for FY 2019-20

Type of Project	Proposed Budget 2019-2020
System upgrade for high efficiency and uniformity	1,525,000
Lighting controls	200,000
Total 2019-2020 CIP	**$ 1,725,000.00**

Combined Utilities- Budget Summary and Cash Flow

PUBLIC UTILITIES
WATER, SEWER, STORMWATER, AND STREET LIGHTING ENTERPRISE FUNDS
COMBINED BUDGET SUMMARY
2020-2022 BUDGET

Combined Annual Rate Increase				8.2%	10.0%	10.1%
SOURCES	ACTUAL 2017-2018	AMENDED BUDGET 2018-2019	PROJECTED ACTUAL 2018-2019	PROPOSED BUDGET 2019-2020	FORECAST BUDGET 2020-2021	FORECAST BUDGET 2021-2022
REVENUES						
METERED SALES	$111,480,405	$119,822,012	$118,657,859	**$129,931,953**	$143,336,576	158,243,087
INTEREST INCOME	2,630,722	1,512,000	1,512,000	**883,820**	$318,816	185,338
OTHER REVENUES	5,931,175	3,282,985	3,284,985	**3,308,157**	$3,308,157	3,308,157
STREET LIGHTING FEES	4,198,227	4,170,000	4,198,227	**4,198,227**	$4,198,227	4,198,227
TOTAL REVENUES	$124,240,529	$128,786,997	$127,653,071	**$138,322,157**	$151,161,776	165,934,809
OTHER SOURCES						
GRANTS & OTHER RELATED REVENUES	$3,333,556	$3,875,000	$3,875,000	**$3,741,000**	$3,741,000	2,441,000
IMPACT FEES	2,858,059	1,400,000	1,400,000	**1,900,000**	1,924,500	1,949,858
TRANSFERS FROM GENERAL FUND	20,000	20,000	20,000	**20,000**	20,000	20,000
BOND PROCEEDS	0	0	0	**105,084,000**	81,453,000	129,847,200
NON BOND FINANCING	8,500,000	4,000,000	0	**0**	67,429,000	85,926,000
SHORT-TERM FINANCING	0	1,355,000	0	**0**	0	0
COUNTY FLOOD CONTROL	0	0	0	**0**	0	0
OTHER SOURCES	118,152	70,000	70,000	**70,000**	70,000	70,000
T O T A L OTHER SOURCES	$14,829,767	$10,720,000	$5,365,000	**$110,815,000**	$154,637,500	220,254,058
T O T A L SOURCES	$139,070,296	$139,506,997	$133,018,071	**$249,137,157**	$305,799,276	386,188,867
EXPENSES & OTHER USES						
EXPENDITURES						
PERSONNEL SERVICES	$30,935,175	$35,516,006	$35,516,006	**$38,021,063**	$39,541,905	41,123,577
OPERATING & MAINTENANCE	$4,951,624	6,362,247	$6,362,247	**$6,733,060**	6,856,022	6,993,143
TRAVEL & TRAINING	$101,729	249,058	$249,058	**304,773**	310,870	317,086
UTILITIES	$4,289,708	5,069,662	$5,069,662	**5,034,877**	5,074,877	5,123,765
TECHNICAL SERVICES	$7,156,710	15,878,757	$15,878,757	**13,638,603**	12,572,550	12,529,406
DATA PROCESSING	$1,765,209	1,487,047	$1,487,047	**1,876,347**	1,913,875	1,952,151
PUBLIC SERVICES / STREET SWEEPING	$819,605	819,605	$819,605	**819,605**	835,997	852,717
FLEET MAINTENANCE	1,821,898	2,007,000	$2,007,000	**2,007,000**	2,047,140	2,088,082
ADMINISTRATIVE SERVICE FEE	1,089,863	1,225,000	$1,225,000	**1,251,000**	1,276,020	1,301,540
PAYMENT IN LIEU OF TAXES	814,795	970,192	$970,192	**1,126,697**	1,149,231	1,172,216
RISK MANAGEMENT	1,313,881	1,484,033	$1,484,033	**1,468,353**	1,497,720	1,527,673
TRANSFERS TO GENERAL FUND	0	109,000	$109,000	**89,000**	90,780	92,596
BILLING COST	1,237,745	1,368,013	$1,368,013	**1,373,051**	1,400,512	1,428,523
BONDING NOTE EXPENSE	0	0	$0	**-**	-	-
METRO. WATER PURCH & TREAT	15,528,950	15,994,818	$15,994,818	**16,474,663**	16,968,903	17,477,971
METRO ASSESSMENT (CAPITAL)	7,021,892	7,021,892	$7,021,892	**7,021,892**	7,021,892	7,021,892
OTHER CHARGES AND SERVICES	(869,406)	(180,918)	($180,918)	**195,595**	198,370	202,338
TOTAL EXPENDITURES	$77,979,378	$95,381,412	$95,381,412	**$97,435,579**	$98,756,664	101,204,676
OTHER USES						
CAPITAL OUTLAY	$6,193,492	$11,144,372	$6,716,975	**$11,931,596**	$4,373,000	4,373,000
CAPITAL IMPROVEMENT BUDGET	55,576,281	177,425,517	91,909,315	**172,094,600**	189,219,500	255,098,400
COST OF DEBT ISSUANCE	9,100	25,000	0	**584,000**	453,000	722,200
DEBT SERVICES	7,645,659	8,292,000	8,284,603	**16,062,000**	18,282,000	20,218,000
T O T A L OTHER USES	$69,424,532	$196,886,889	$106,910,893	**$200,672,196**	$212,327,500	280,411,600
T O T A L USES	$147,403,910	$292,268,301	$202,292,305	**$298,107,775**	$311,084,164	381,616,276
EXCESS REVENUE AND OTHER SOURCES OVER (UNDER) USES	($8,333,614)	($152,761,304)	($69,274,234)	**($48,970,618)**	($5,284,888)	4,572,591
OPERATING CASH BALANCES						
BEGINNING JULY 1	$152,753,095	$144,419,481	$144,419,481	**$75,145,247**	$26,174,629	20,889,741
ENDING JUNE 30	$144,419,481	($8,341,823)	$75,145,247	**$26,174,629**	$20,889,741	25,462,332
Cash Reserve Ratio	185%	-9%	79%	**27%**	21%	25%

Cash reserve goal above 10%

PUBLIC UTILITIES
Water, Sewer, Stormwater and Street Lighting Enterprise Funds
Combined Cash Flow
FY 2020 Budget and FY 2021-2024 Forecast Budget

	ACTUAL YEAR 2017-2018	PROJECTED YEAR 2018-2019	BUDGET YEAR 2019-2020	BUDGET YEAR 2020-2021	BUDGET YEAR 2021-2022	BUDGET YEAR 2022-2023	BUDGET YEAR 2023-2024
WATER SALES	69,351,147	72,125,193	75,731,453	79,784,026	83,773,227	87,961,888	93,239,601
SEWER CHARGES	33,620,751	37,677,666	44,460,000	52,838,000	62,791,000	72,718,000	80,548,000
STORMWATER FEES	8,508,507	8,855,000	9,740,500	10,714,550	11,678,860	12,379,591	12,998,571
STREET LIGHTING FEES	4,198,227	4,198,227	4,198,227	4,198,227	4,198,227	4,198,227	4,198,227
TOTAL SERVICES FEES AND CHARGES	115,678,632	122,856,086	134,130,180	147,534,803	162,441,314	177,257,706	190,984,399
OTHER INCOME	5,934,020	3,304,985	3,328,157	3,328,157	3,328,157	3,328,157	3,328,157
INTEREST INCOME	2,630,722	1,512,000	883,820	318,816	185,338	256,254	203,104
OPERATING INCOME	124,243,374	127,673,071	138,342,157	151,181,776	165,954,809	180,842,117	194,515,660
OPERATING EXPENDITURES	(77,986,578)	(95,381,412)	(97,435,579)	(98,756,664)	(101,204,676)	(103,806,581)	(106,203,662)
NET INCOME EXCLUDING DEP.	46,256,796	32,291,659	40,906,578	52,425,112	64,750,133	77,035,536	88,311,998
WIFIA LOAN			0	67429000	85926000	65057000	31865000
NET BOND PROCEEDS	0	0	104,500,000	81,000,000	129,125,000	94,000,000	42,000,000
SHORT TERM FINANCING	0	0	0	0	0	0	0
STATE LOAN	8,500,000	0	0	0	0	0	0
IMPACT FEES	2,858,059	1,400,000	1,900,000	1,924,500	1,949,858	1,976,103	2,003,267
OTHER CONTRIBUTIONS	3,468,863	3,945,000	3,811,000	3,811,000	2,511,000	2,311,000	2,311,000
CAPITAL OUTLAY	(6,193,492)	(6,126,238)	(10,431,596)	(2,873,000)	(2,873,000)	(2,873,000)	(2,873,000)
WATERSHED PURCHASES	0	(590,737)	(1,500,000)	(1,500,000)	(1,500,000)	(1,500,000)	(1,500,000)
STATE LOAND DEBT SERVICE	0	0	(6,375,000)	(2,125,000)	0	0	0
SHORT TERM FINANCING DEBT SERVICE	0	0	0	0	0	0	0
DEBT SERVICE	(7,647,559)	(8,284,603)	(8,297,000)	(10,861,000)	(10,854,000)	(10,851,000)	(11,183,850)
NEW DEBT SERVICE	0	0	(1,390,000)	(5,296,000)	(9,364,000)	(14,459,000)	(20,281,000)
OTHER INCOME & EXPENSE	985,871	(9,656,578)	82,217,404	131,509,500	194,920,858	133,661,103	42,341,417
AVAILABLE FOR CAPITAL	47,242,667	22,635,081	123,123,982	183,934,612	259,670,991	210,696,639	130,653,415
CAPITAL IMPROVEMENTS	(55,576,281)	(91,909,315)	(172,094,600)	(189,219,500)	(255,098,400)	(214,028,000)	(130,399,000)
BEGINING CASH BALANCE	152,753,095	144,419,481	75,145,247	26,174,629	20,889,741	25,462,332	21,880,971
CASH INCREASE/(DECREASE)	(8,333,614)	(69,274,234)	(48,970,618)	(5,284,888)	4,572,591	(3,331,361)	254,415
ENDING BALANCES	144,419,481	75,145,247	26,174,629	20,889,741	25,462,332	22,130,971	22,135,386
DEBT SERVICE COVERAGE	6.05	3.90	4.22	3.24	3.20	3.04	2.81
CASH RESERVE RATIO	185.2%	78.8%	26.9%	21.2%	25.2%	21.3%	20.8%
DEBT SERVICE % OF GROSS OPERATING REVENUE	6.3%	6.5%	6.9%	10.5%	12.1%	13.9%	16.1%
RESIDENTIAL UTILITY BILL	63.65	67.46	70.25	75.76	81.86	87.88	93.81
% CHANGE RESIDENTIAL UTILITY BILL*		6.0%	4.14%	7.8%	8.1%	7.4%	6.7%

*** Residential Utility Bill assumes annual water consumption of 255 ccf/12 months, 4 ccf monthly of sewer, 1 Stormwater ERU (.25 acres) monthly, and 1 Street Lighting ERU (75 feet) monthly.**

PUBLIC UTILITIES
FEES AND CHARGES PAID TO THE GENERAL FUND
FOR SERVICES RENDERED
OR COLLECTED BY CITY ORDINANCE

DESCRIPTION OF SERVICES	June 30, 2018 ACTUALS WATER	June 30, 2018 ACTUALS SEWER	June 30, 2018 ACTUALS STORM	June 30, 2018 ACTUALS STREET LIGHT	ACTUAL Public Utilities June 30, 2018 TOTALS	FY 2018/2019 BUDGET	FY PROPOSED 2019/2020 BUDGET
Administrative Service Fees (General Fund)							
Human Resources	$ 144,501	$ 124,064	$ 33,232	$ 1,954	$ 303,751	$ 358,450	**$ 348,670**
City Attorney	135,198	22,364	10,165	2,033	169,760	167,350	**194,860**
Accounting/Finance	131,822	58,626	12,442	3,569	206,459	272,280	**236,980**
Purchasing & Contracts	66,060	27,842	3,213	2,607	99,722	96,130	**114,470**
City Recorders	45,263	7,259	7,651	867	61,040	86,260	**70,060**
Property Management	-	-	-	-	-	7,770	**-**
Budget and Policy	25,667	10,732	3,041	217	39,657	45,780	**45,520**
Non-discretionary IMS Costs	50,630	27,072	13,881	1,094	92,677	197,480	**106,380**
Treasurer's Office (cash mgt.)	11,272	4,585	3,974	2,952	22,783	13,970	**26,150**
City Council	37,787	22,758	13,311	16,746	90,602	50,960	**104,000**
Mayor	326	326	326	-	978	3,070	**1,120**
Community Affairs	1,012	632	379	411	2,434	1,000	**2,790**
Total Admin Fees	$ 649,538	$ 306,260	$ 101,615	$ 32,450	$ 1,089,863	$ 1,300,500	**$ 1,251,000**
Tax or Fee Authorized							**-**
Payment in Lieu-of-Taxes (General Fund)	$ 398,485	$ 306,525	$ 109,785	$ -	$ 814,795	$ 831,092	**1,126,697**
Franchise Fees (General Fund)	2,810,068	1,374,769	350,175	-	4,535,012	5,622,628	**6,147,049**
Sub Total	$ 3,208,553	$ 1,681,294	$ 459,960	$ -	$ 5,349,807	$ 6,453,720	**$ 7,273,746**
Internal Service Fund Services							
Fleet Mgt. Services	$ 1,029,585	$ 568,448	$ 223,731	$ -	$ 1,821,764	$ 2,042,040	**$ 2,007,000**
City Data Processing (IMS)	912,977	381,234	294,929	1,117	1,590,257	933,300	**1,539,000**
Telephone Charges	-	-	-	-	-	94,248	**8,400**
Risk Mgt. Admininstrative Fees (Gov. Immunity)	111,519	44,317	3,048	-	158,884	246,381	**216,550**
Risk Management Premiums & Charges	632,362	258,886	54,937	-	946,185	1,495,502	**1,251,803**
Sub Total	$ 2,686,442	$ 1,252,885	$ 576,645	$ 1,117	$ 4,517,090	$ 4,811,471	**5,022,753**
Special Associated Charges (indirect benefit)							
OneSolution Maintenance (network financial syste	$ -	$ -	$ -	$ -	$ -	$ 111,180	**89,000**
Street Sweeping	-	-	819,605	-	819,605	835,997	**819,605**
Neighborhood Clean-up	-	-	-	-	-	118,000	**-**
Emergency Management	-	-	-	-	-	30,000	**-**
Tracy Aviary Stormwater Education Cost	-	-	154,350	-	154,350	75,000	**75,000**
Sub Total	$ -	$ -	$ 973,955	$ -	$ 973,955	$ 1,170,177	**$ 983,605**
TOTAL FEES, TAXES AND CHARGES	$ 6,544,533	$ 3,240,440	$ 2,112,175	$ 33,567	$ 11,930,715	$ 13,735,868	**$ 14,531,104**

Public Utilities Proposed Consulting Studies for FY 2019-2020

Division	Cost Center	Study or Project Description	Lighting	Water	Sewer	Storm	Total
Administration	5103000	5-Year Emergency Preparedeness Plan		12,000			12,000
Administration	5100200	Well Study		20,000			20,000
Administration	5103000	Ongoing Environmental Assessments for PU facilities		20,000			20,000
Administration	5103400	Standards development		20,000			20,000
Administration	5103600	Water Conservation		50,000			50,000
Administration	5100200	Central Wasatch Commission		200,000			200,000
Engineering	4848000	Street Light Master Plan	90,000				90,000
Engineering	5210400	Basin Inflow Testing			300,000		300,000
Engineering	5210400	Jacobs Program Support			350,000		350,000
Engineering	5310300	Jacobs Program Support				50,000	50,000
Engineering	5310300	Storm Water Master Plan				700,000	700,000
Engineering	5101300	Water loss study		100,000			100,000
Engineering	5101300	AMP for Storage Reservors		135,000			135,000
Engineering	5101300	Campus study		350,000			350,000
Engineering	5101300	Jacobs Program Support		400,000			400,000
Engineering	5101300	Water Master Plan		500,000			500,000
Finance	5211700	Energy Retro-Commissioning Study			55,000		55,000
Finance	5310500	Energy Retro-Commissioning Study				35,000	35,000
Finance	5103200	Adjudication and other administrative needs.		500,000			500,000
GIS	5101600	Water Data Tracking Software & Consultant		250,000			250,000
Maintenance	5310200	Clean parts of Irrigation system				25,000	25,000
Maintenance	5100100	Geotech consultants		50,000			50,000
Maintenance	5100100	Consulting Project for Canals		60,000			60,000
Maintenance	5100300	Consultants for Well Issues		100,000			100,000
Reclamation	5212400	Study to identify inhibiting-causing pollutants at the WRF			40,000		40,000
Reclamation	5212400	Study to evaluate and determine updated local wastewater discharge limits			60,000		60,000
Reclamation	5212400	Study to evaluate and determine updated sewer rate classifications			250,000		250,000
Water Quality	5310700	Consultant to address MS4 Audit/QAQC				20,000	20,000
Water Quality	5310700	TMDL Load Allocation				50,000	50,000
Water Quality	5100600	Misc Needs		15,000			15,000
Water Quality	5100600	PR Campaign additional Funds		30,000			30,000
Water Quality	5101800	Public Relations		30,000			30,000
Water Quality	5101800	Utah State University Canal Water Quality Analysis		32,000			32,000
Water Quality	5101800	Process Controls		35,000			35,000
Water Quality	5100600	Watershed Plan		120,000			120,000
			$ 90,000	**$ 3,029,000**	**$ 1,055,000**	**$ 880,000**	**$ 5,054,000**

<u>Water Utility- Budget Summary and Cash Flow</u>

WATER UTILITY
ENTERPRISE FUND
BUDGET SUMMARY
Fiscal Years 2020-22

SOURCES	ACTUAL 2017-18	AMENDED BUDGET 2018-19	PROJECTED ACTUAL 2018-19	PROPOSED BUDGET 2019-20 (Rate Increase 5%)	FORECAST BUDGET 2020-21 (Rate Increase 5%)	FORECAST BUDGET 2021-22 (Rate Increase 5%)
	-					
REVENUES						
METERED SALES	$69,351,147	$73,289,346	$72,125,193	**$75,731,453**	$79,784,026	$83,773,227
INTEREST INCOME	831,749	375,000	375,000	**229,000**	92,000	89,000
OTHER REVENUES	4,240,466	3,037,985	3,037,985	**3,063,157**	3,063,157	3,063,157
TOTAL REVENUES	$74,423,362	$76,702,331	$75,538,178	**$79,023,610**	$82,939,183	$86,925,384
OTHER SOURCES						
GRANTS & OTHER RELATED REVENUES	$1,804,748	$1,205,000	$1,205,000	**$1,205,000**	$1,205,000	$1,205,000
IMPACT FEES	1,520,259	500,000	500,000	**1,000,000**	1,000,000	1,000,000
OTHER SOURCES	115,307	50,000	50,000	**50,000**	50,000	50,000
BOND PROCEEDS	-	-	-	**35,196,000**	42,235,000	26,146,000
T O T A L OTHER SOURCES	$3,440,314	$1,755,000	$1,755,000	**$37,451,000**	$44,490,000	$28,401,000
T O T A L SOURCES	$77,863,676	$78,457,331	$77,293,178	**$116,474,610**	$127,429,183	$115,326,384
EXPENSES & OTHER USES						
EXPENDITURES						
PERSONNEL SERVICES	$19,852,264	$22,069,746	$22,069,746	**23,387,302**	$24,322,796	$25,295,713
OPERATING & MAINTENANCE	3,392,135	4,233,777	4,233,777	**4,415,380**	4,492,588	4,582,441
TRAVEL & TRAINING	45,173	146,408	146,408	**167,083**	170,426	173,834
UTILITIES	2,397,853	2,854,647	2,854,647	**2,784,962**	2,840,660	2,897,473
TECHNICAL SERVICES	3,657,447	8,726,160	8,726,160	**7,543,867**	6,490,344	6,390,712
DATA PROCESSING	1,065,047	967,347	967,347	**1,177,347**	1,200,895	1,224,911
FLEET MAINTENANCE	1,029,720	1,250,000	1,250,000	**1,250,000**	1,275,000	1,300,500
ADMINISTRATIVE SERVICE FEE	649,538	800,000	800,000	**800,000**	816,000	832,320
PAYMENT IN LIEU OF TAXES	398,485	476,000	476,000	**365,000**	372,300	379,746
METRO. WATER PURCH & TREAT	15,528,950	15,994,818	15,994,818	**16,474,663**	16,968,903	17,477,971
METRO ASSESSMENT (CAPITAL)	7,021,892	7,021,892	7,021,892	**7,021,892**	7,021,892	7,021,892
RISK MANAGEMENT	952,332	1,088,550	1,088,550	**1,123,187**	1,145,651	1,168,563
TRANSFERS TO GENERAL FUND	0	85,000	85,000	**85,000**	86,700	88,434
OTHER CHARGES AND SERVICES	(1,032,212)	(359,811)	(359,811)	**(319,913)**	(328,020)	(334,579)
TOTAL EXPENDITURES	$54,958,624	$65,354,534	$65,354,534	**$66,275,770**	$66,876,135	$68,499,931
OTHER USES						
CAPITAL OUTLAY	$5,148,158	$4,682,304	$4,898,838	**$2,509,447**	$2,930,000	$2,930,000
CAPITAL IMPROVEMENT BUDGET	18,041,425	51,641,293	24,629,211	**59,255,100**	53,501,500	38,542,400
COST OF DEBT ISSUANCE	1,900	0	0	**196,000**	235,000	146,000
DEBT SERVICES	967,961	1,117,000	1,117,000	**1,585,000**	3,043,000	4,600,000
T O T A L OTHER USES	$24,159,444	$57,440,597	$30,645,049	**$63,545,547**	$59,709,500	$46,218,400
T O T A L USES	$79,118,068	$122,795,131	$95,999,583	**$129,821,317**	$126,585,635	$114,718,331
EXCESS REVENUE AND OTHER SOURCES OVER (UNDER) USES	($1,254,392)	($44,337,800)	($18,706,405)	**($13,346,707)**	$843,548	$608,053
OPERATING CASH BALANCES						
BEGINNING JULY 1	$47,048,055	$45,793,663	$45,793,663	**$27,087,258**	$13,740,551	$14,584,099
ENDING JUNE 30	$45,793,663	$1,455,863	$27,087,258	**$13,740,551**	$14,584,099	$15,192,152
Cash Reserve Ratio	83%	2%	41%	**21%**	22%	22%

Cash reserve goal above 10%

WATER UTILITY
Cash Flow
FY 2020 Budget
and FY 2021-2024 Budget Forecast

Rates +5% FY20 - FY23 +6% FY24
Bonds Total $169M, $35M,$42M,$26M,$29M,$15M ...
CIP 100%, New Bond Pmts thru FY 24: $21.3

	ACTUAL YEAR 2017-2018	PROJECTED YEAR 2018-2019	BUDGET YEAR 2019-2020	BUDGET YEAR 2020-2021	BUDGET YEAR 2021-2022	BUDGET YEAR 2022-2023	BUDGET YEAR 2023-2024
WATER SALES	69,351,147	72,125,193	75,731,453	79,784,026	83,773,227	87,961,888	93,239,601
OTHER INCOME	4,240,466	3,037,985	3,063,157	3,063,157	3,063,157	3,063,157	3,063,157
INTEREST INCOME	831,749	375,000	229,000	92,000	89,000	90,000	93,000
OPERATING INCOME	74,423,362	75,538,178	79,023,610	82,939,183	86,925,384	91,115,045	96,395,758
METROPOLITAN WATER ASSESSMENT	(7,021,892)	(7,021,892)	(7,021,892)	(7,021,892)	(7,021,892)	(7,021,892)	(7,021,892)
METROPOLITAN WATER PURCHASES	(15,528,950)	(15,994,819)	(16,474,663)	(16,968,903)	(17,477,971)	(18,002,310)	(18,542,380)
OPERATING EXPENDITURES	(32,407,782)	(42,337,823)	(42,779,215)	(42,885,337)	(44,000,060)	(45,120,974)	(46,539,544)
NET INCOME EXCLUDING DEP.	19,464,738	10,183,644	12,747,840	16,063,051	18,425,461	20,969,869	24,291,942
NET BOND PROCEEDS			35,000,000	42,000,000	26,000,000	29,000,000	15,000,000
BIC Borrowed			196,000	235,000	146,000	162,000	84,000
BIC Paid			(196,000)	(235,000)	(146,000)	(162,000)	(84,000)
SHORT TERM FINANCING							
IMPACT FEES	1,520,259	500,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000
OTHER CONTRIBUTIONS	1,920,055	1,255,000	1,255,000	1,255,000	1,255,000	1,255,000	1,255,000
CAPITAL OUTLAY	(5,148,158)	(4,308,101)	(1,009,447)	(1,430,000)	(1,430,000)	(1,430,000)	(1,430,000)
WATERSHED PURCHASES	0	(590,737)	(1,500,000)	(1,500,000)	(1,500,000)	(1,500,000)	(1,500,000)
DEBT SERVICE	(969,861)	(1,117,000)	(1,127,000)	(1,085,000)	(1,090,000)	(1,091,000)	(1,040,000)
NEW DEBT SERVICE	0	0	(458,000)	(1,958,000)	(3,510,000)	(4,730,000)	(6,625,000)
OTHER INCOME & EXPENSE	(2,677,705)	(4,260,838)	33,160,553	38,282,000	20,725,000	22,504,000	6,660,000
GENERATED FOR CAPITAL	16,787,033	5,922,806	45,908,393	54,345,051	39,150,461	43,473,869	30,951,942
CAPITAL IMPROVEMENTS	**(18,041,425)**	**(24,629,211)**	**(59,255,100)**	**(53,501,500)**	**(38,542,400)**	**(42,350,000)**	**(29,914,000)**
BEGINING CASH BALANCE	47,048,055	45,793,663	27,087,258	13,740,551	14,584,102	15,192,163	16,316,032
CASH INCREASE/(DECREASE)	(1,254,392)	(18,706,405)	(13,346,707)	843,551	608,061	1,123,869	1,037,942
ENDING BALANCES	45,793,663	27,087,258	13,740,551	14,584,102	15,192,163	16,316,032	17,353,974
RESTRICTED / RESERVED CASH	(23,928,611)	(8,952,141)	(8,952,141)	(8,952,141)	(8,952,141)	(8,952,141)	(8,952,141)
AVAILABLE ENDING BALANCE	21,865,052	18,135,117	4,788,410	5,631,961	6,240,022	7,363,891	8,401,833
S&P COVERAGE (INCLUDES MWA AS DEBT SERVICE)		**2.11**	2.30	**2**	**2.19**	**2.18**	**2.13**
DEBT SERVICE COVERAGE	**20.07**	**9.12**	**8.04**	**5**	**4.01**	**3.60**	**3.17**
RATE CHANGE	**4%**	**4%**	**5%**	**5%**	**5%**	**5%**	**6%**
Cash Reserve Ratio (Total Cash)	**83%**	**41%**	**21%**	**22%**	**22%**	**23%**	**24%**
DEBT SERVICE % OF GROSS OPERATING REVENUE	1.30%	1.45%	1.95%	3.57%	5.16%	6.23%	7.77%
MONTHLY RESIDENTIAL BILL (255 ccf annually/12 mos.)	44.83	46.60	46.41	48.74	51.18	53.74	56.97

WATER UTILITY CIP BUDGET
Five Year Projected Budget FY2020-2024

COST CENTER	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	CRITICALITY RATING	CONDITION RATING	PAST YEAR SPENT 2018-19 (Calc'd from P6)	BUDGET YEAR 2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
51-01301-	2720.10		**MAINTENANCE & REPAIR SHOPS**									
01401		2015-0460	DISTRIBUTION AND ELECTRICAL BARN	4	4	0						850,000
			CAMPUS	5	5					15,000,000	10,000,000	
03201	512185		FUEL PUMP AWNINGS	5	0	0				250,000		
						$ -	$ -	$ -	$ -	$ 15,250,000	$ 10,000,000	$ 850,000
51-01301-	2720.30		**TREATMENT PLANTS**									
			CITY CREEK									
00701	5122628	2015-0178	DRYING BED PIPELINES	5	5	723,637						
00701	5122665	2015-0685	CCWTP CONTINGENCY PROJECTS	5	5	0						
00701	512260079	2017-2043	TREATMENT PLANT UPGRADES (PENDING 2019 ASSESSMENT RESULTS; DESIGN AND CONST	5	5	326,088	1,500,000	1,500,000	1,500,000	1,500,000	1,500,000	
00701	5122674		HYPOGENERATOR DESIGN	3	0	0						
00701		2015-0177	CITY CREEK - ACTUATORS/SCADA (MULTIPLE LOCATIONS)	3	3	0						
00701		2015-0182	IMPLEMENTATION OF SCADA MASTER PLAN	3	3	0						
00701		2015-0447	CLARIFIER UPGRADE	3	3	0						
00701		2015-0702	ELECTRICAL SYSTEM ASSESSMENT AND UPGRADE	5	4	0						
00701		2016-0871	SEISMIC UPGRADE FILTER BUILDIING STUDY	5	4	0						
00701		2016-0876	PRESSURE DIFFERENTIAL TRANSMITTERS	3	4	0						
00701		2016-0880	CREEK CHANNEL	3	4	0						
00701		2016-0881	FILTER/FLUORIDE BUILDING GATE	3	4	0						
00701		2017-1297	PUMP BACK SYSTEM	2	0	0						
00701		2018-1098	CITY CREEK FILTER MEDIA REPLACEMENT	4	5	0						
00701		2019-1001	CITY CREEK WTP UPGRADES - PHASE 2	5	3	0						30,000,000
00701	512260078	2016-0879	BACKWASH TANK SEISMIC UPGRADE AND RETAINING WALL	5	4	62,473						
00701	512260077	2017-2042	CITY CREEK CCTV SYSTEM UPGRADE	5	4	18,000						
00701	5122676		COAGULATION BUILDING DEMOLITION			101,669						
						$ 1,231,866	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 30,000,000
			PARLEY'S									
00801	5124561	2015-0686	PWTP CONTINGENCY PROJECTS	5	5	0						
00801	512450070	2015-0688	FILTER ASSESSMENT AND FILTER #5 REPAIR	5	5	75,000						
00801	5124525	2015-0203	REPLACE SLUDGE COLLECTION SYSTEM FLIGHTS, CHAINS, AND DRIVES	5	5	1,898,136						
00801	5124506	2015-0201	LABORATORY UPGRADE (BUILD)	5	4	1,284,460						
00801	512450068	2015-0701	PLANT DESIGN AND UPGRADES	5	4	205,880	1,500,000	10,000,000	2,000,000	2,000,000	2,000,000	
00801	5124532		REPLACEMENT OF CHEMICAL FEED PUMPS PARLEY'S CANYON			0						
00801	512450069	2015-0594	BACK-UP WATER SUPPLY FOR HIGH PRESSURE TANK	5	3	0						
00801		2015-0695	RELOCATE POTASSIUM PERMANGANATE FEED SYSTEM	4	4	0						
00801	5124526	2015-0455	INFLUENT CONTROL BOX	4	3	0						
00801	512450066	2016-0867	ROOF REPLACEMENT	4	5	0						
00801	512450067	2016-0874	REBUILD/REPLACE FLOC-SED BASIN VENTILATION SYSTEM	2	5	0						
00801		2015-0450	PRECURSOR - TASTE AND ODOR CONTROL	3	3	0						
00801	5124504	2015-0449	SLUDGE BEDS - PIPING AND VALVES	2	3	0						
00801		2015-0197	ELECTRICAL CONDUITS/PAVING TO BLOW-OFF BOX/ASPHALT EAST AND SOUTH OF FA(	3	3	0						
00801		2015-0204	REPLACE FLOCCULATORS	4	4	0						
00801		2015-0448	SCADA MASTER PLAN IMPLEMENTATION	4	4	0						
00801		2015-0452	NEW I/O AND PLC	2	1	0						
00801		2017-2005	PROCESS UPGRADES (FROM SED BASIN PREDESIGN)	1	0	0						
00801		2017-2006	VERTICAL FLOCCULATOR INSTALLATION	5	3	0						
00801	512450072	2016-1280	PLANT LIGHTING	5	4	30,000						
00801	512450073		SODIUM HYPOCHLORITE STORAGE TANK FOR PWTP AND BCWTP			40,000	300,000					
00801		2018-1037	PARLEYS DIVERSION SCREEN PROJECT	4	0	0	250,000	1,250,000				1,500,000

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00801		2018-1095	PARLEYS FINISHED WATER RESERVOIR	3	0	0						20,000,000
00801		2018-1094	NEW PARLEYS WATER TREATMENT PLANT	5	4	0						136,500,000
						$ 3,533,477	$ 2,050,000	$ 11,250,000	$ 2,000,000	$ 2,000,000	$ 2,000,000	$ 158,000,000
			BIG COTTONWOOD									
00901	51262759	2015-0186	SCADA MASTER PLAN/OPERATOR STATION UPGRADE IMPLEMENTATION			0	300,000					
00901	512627462	2015-0684	BCWTP CONTINGENCY PROJECTS	5	5	0						
00901	512627460	2015-0192	SEDIMENTATION BASIN REBUILD	5	5	829,641						
00901		2019-1002	BIG COTTONWOOD WTP REBUILD - PHASE 1	5	4	0	2,500,000	5,000,000	2,500,000	2,000,000	2,000,000	80,000,000
00901		2015-0191	BIG COTTONWOOD - ASPHALT LOWER-END OF BUILDING TO DRYING BEDS	5	5	0						
00901	512627469	2017-2049	RELOCATION AND HOUSING OF SWITCHGEAR	5	5	0						
00901		2015-0188	FINISHED WATER FLOW METER/FINISHED WATER SAMPLE POINT	5	4	0						
00901		2016-1236	90 FOOT CHANNEL UPGRADES	4	4	0						
00901		2015-0190	REPLACE FLOCCULATION SHAFT DRIVES AND EQUIPMENT	4	4	0						150,000
00901		2015-0698	REROOF COAGULATION BUILDING	4	3	0						100,000
00901		2018-1030	BIG COTTONWOOD SLUDGE SYSTEM UPGRADE	5	4	0						1,500,000
00901		2018-1043	BIG COTTONWOOD WTP REBUILD - PHASE 2	5	4	0						75,000,000
00901		2015-0189	2-10 MILLION GALLON FINISHED WATER STORAGE RESERVOIR	3	3	0						
00901	512627470	2015-0713	HVAC UPGRADES IN FILTER ROOM	5	5	45,044						
00901	512627457	2016-1279	PLANT LIGHTING	5	4	30,000						
00901		2018-1099	FILTER ASSESSMENT AND IMPROVEMENTS	5	4	0	1,500,000					
						$ 904,685	$ 4,300,000	$ 5,000,000	$ 2,500,000	$ 2,000,000	$ 2,000,000	$ 156,750,000
			TOTAL TREATMENT PLANTS			$ 5,670,028	$ 7,850,000	$ 17,750,000	$ 6,000,000	$ 5,500,000	$ 5,500,000	$ 344,750,000
51-01301-	2720.35		**PUMPING PLANTS AND PUMP HOUSES**									
01301	513416331		EAST BENCH PUMP STATION - FULL BACKUP POWER	5	5	623,996						
01301		2016-1174	5TH AVE AND U ST PUMP STATION BACKUP POWER	5	5	0	400,000					
01301	513416364	2016-1282	BONNEVILLE AND EAST BENCH PUMP STATION - PUMP UPGRADES	5	5	24,000						
01301	513416365	2015-0514	NORTH BENCH PUMP STATION ROOF	4	5	27,494						
01301	513505271	2015-0378	UPLAND DR PROJECT	4	5	0	800,000					
01301	513800033	2015-0555	3900 SOUTH BIRCH DRIVE VALVE VAULT	4	4	8,142						
01301	513416359	2016-0888	3900 SOUTH PUMP STATION	4	4	313,408	30,000	3,600,000	7,200,000			
01301	513416366	2015-0531	GOLDEN HILLS PUMP STATION	3	5	90,000	60,000					
01301	513416367	2016-1208	5TH AND U PUMP STATION IMPROVEMENTS	4	4	12,981	275,000					
01301	513416361	2015-0563	OAKHILLS PUMP STATION - MCC - VFD - PUMP UPGRADE	3	3	0		550,000				
01301		2016-0937	ENSIGN DOWNS PS VFD	3	3	0			20,000			
01301	513416336	2015-0428	MP 3.12 B - 7800 SOUTH AUXILIARY POWER	3	3	0			305,000			
01301		2016-1179	300 EAST PUMP STATION BACKUP POWER	3	3	0			400,000			
01301		2016-1180	3300 SOUTH BOOSTER PUMP STATION BACKUP POWER	3	3	0			400,000			
01301		2016-1181	KENTON DRIVE PUMP STATION BACKUP POWER	3	3	0			400,000			
01301		2016-1183	VIRGINIA AND MILLCREEK PUMP STATION BACKUP POWER	3	3	0				400,000		
01301		2016-1184	EASTWOOD PUMP STATION BACKUP POWER	3	3	0				400,000		
01301		2016-1185	MILLCREEK PUMP STATION BACKUP POWER	3	3	0				400,000		
01301		2016-1186	39TH AND BIRCH PUMP STATION BACKUP POWER	3	3	0				400,000		
01301		2016-1187	CANYON COVE PUMP STATION BACKUP POWER	3	3	0					400,000	
01301		2016-1188	7800 SOUTH PUMP STATION BACKUP POWER	3	3	0					400,000	
01301		2016-1189	GOLDEN HILLS PUMP STATION BACKUP POWER	3	3	0					400,000	
01301		2016-1190	CARRIGAN COVE PUMP STATION BACKUP POWER	3	3	0					400,000	
01301		2016-1173	NORTH BENCH PUMP STATION BACKUP POWER	3	3	0						400,000
01301		2016-1175	UNIVERSITY PUMP STATION BACKUP POWER	3	3	0						400,000

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01301		2016-1176	RESEARCH PARK PUMP STATION BACKUP POWER	3	3	0						400,000
01301		2016-1177	OAK HILLS PUMP STATION BACKUP POWER	3	3	0						400,000
01301		2016-1178	BONNEVILLE PUMP STATION BACKUP POWER	3	3	0						400,000
01301		2016-1191	3900 SOUTH BOOSTER PUMP STATION BACKUP POWER	3	3	0						400,000
01301		2016-1192	6200 SOUTH IRRIGATION PUMP STATION BACKUP POWER	3	3	0						400,000
01301		2016-1193	EMIGRATION PUMP STATION BACKUP POWER	3	3	0						400,000
01301		2016-1223	5TH AVE AND U ST PUMP STATION VFD'S	3	3	0						200,000
01301		2016-1224	ARLINGTON HILLS PUMP STATION VFD'S	3	3	0						200,000
01301		2016-1225	NORTH BENCH PUMP STATION VFD'S	3	3	0					200,000	
01301		2016-1226	5TH AVE AND U ST PUMP STATION PIPING	3	3	0						200,000
01301		2017-2009	REPAIR AND LINE OF UNIVERSITY DRAIN LINE	2	3	0						10,000
01301		2015-0517	4500 SOUTH PUMP STATION BLACK TOP	1	3	0						25,000
01301		2015-0522	RECURRING PUMP STATION REPAIR FUND	3	0	0						50,000
01301	513416329	2015-0169	UV UPGRADE 6200 SOUTH PUMP STATION	1	2	0						300,000
01301		2016-1194	ENSIGN DOWNS PUMP STATION BACKUP POWER	3	0	0						400,000
01301		2015-0172	MP 3.8C - VICTORY ROAD - ENSIGN DOWNS PHASE II - PROPERTY PURCHASE - IF	4	0	0						500,000
01301		2015-0173	4500 SOUTH PUMP STATION (BACK UP)	5	0	0						1,500,000
						$ 1,100,021	$ 1,565,000	$ 4,150,000	$ 8,725,000	$ 1,600,000	$ 1,800,000	$ 6,585,000
51-01301-	2730.02		**CULVERTS FLUMES & BRIDGES**									
01301	5129264		JSL CANAL CONDUIT REPLACEMENT - SUGARHOUSE	5	5	67,976	1,000,000					
01301	513000045	2016-1166	SUGARHOUSE WELL SPLASH PAD	5	5	59,889	150,000					150,000
01301	512900272	2015-0432	VARIOUS CANAL IMPROVEMENTS	5	5	25,000	25,000	25,000	25,000	25,000	25,000	
01301	512900273	2016-0737	IRRIGATION SCADA IMPROVEMENTS	5	5	20,000	50,000	20,000	20,000	20,000	20,000	
01301		2016-0816	ROCKHOUSE DUMP - INTAKE IMPROVEMENT	5	4	0		78,500				
01301	513000034	2016-0858	FLUME FROM DOUBLE BARRELS TO RAILROAD TRACKS	4	4	21,512			1,250,000	1,250,000		
01301	5129246	2015-0158	REPLACE FLUME/AUTO DUMP AND JSL CANAL ENCLOSURE @ MILLCREEK	4	4	0	100,000	468,000				
01301	512900274	2017-2076	HEADGATE REHABILITATION 18/19	4	4	20,000	20,000	20,000	20,000	20,000	20,000	
01301	513000026	2015-0161	E JORDAN TOWER - IMPROVED ACCESS	3	5	20,000		150,000				
01301		2016-1167	6200 SOUTH LIFT STATION WEIR PROTECTION	3	5	0	60,000					
01301	5129231	2015-0152	JSL CANAL - 1750 S EMIGRATION DIVERSION STRUCTURE REBUILD	4	3	0				50,000	290,000	
01301	5129233	2015-0604	JSL 3800 S REHAB FLOOR AND LEAKAGE	3	4	0			18,000			
01301	5129251	2015-0151	JSL ENCLOSURE FROM 1300 EAST TO MILLCREEK	3	3	0						997,000
01301		2015-0168	IMPROVEMENTS TO JSL DUMP AT I-80	3	3	0						11,000
01301	5129235	2015-0606	JSL 4500 SOUTH TO OSAGE ORANGE DRIVE – CANAL BANK HYDRAULICS	3	3	0				20,000		
01301	5129249	2015-0149	NEW IRRIGATION CONDUIT ON HARVARD AVENUE	4	0	0			50,000		402,000	
01301	513000038	2016-0865	OIL SEPARATORS AND DRAINAGE SYSTEM FOR THE ARTESIAN SHOP	4	0	37,500		600,000				
01301		2016-1165	LOW FLOW CHANNEL AT SPENCER'S POND (BIG COTTONWOOD CREEK)	4	0	0					300,000	
01301		2016-1284	1100 EAST DIVERSION STRUCTURE AT WILLINGTON	4	0	0						50,000
01301	5129232	2015-0602	JSL CANAL – MODIFY BIG SPILL TO HANDLE TEMPORARY PUMP	2	2	0					82,000	
01301		2016-1287	STUDY ON WELLS AT WALKER LANE AND FOUNTAIN BEAU	1	3	0						1,000,000
01301		2016-0749	J&SL DIVERSION STRUCTURE AT 2700 SOUTH	2	0	0						350,000
01301		2016-1286	3000 EAST WELL FOR WATER DELIVERIES	2	0	0						2,000,000
01301	5129242	2015-0153	PIPING DITCH ON JSL, OSAGE ORANGE AVENUE TO LINCOLN LANE	1	0	0						175,000
01301		2015-0160	DESPAIN IRRIGATION SYSTEM IMPROVEMENTS	3	3	0						17,000
01301		2015-0603	JSL CANAL/JORDAN RIVER STABILIZATION AT EAST JORDAN DUMP	4	4	0						406,000
01301		2018-1019	14600 SO. CANAL OVER FLOW STRUTURE	3	3	0						500,000
01301		2018-1080	3900SO STORM DRAIN OVER FLOW	2	4	0				50,000	250,000	
01301		2018-1082	LITTLE TANNER PIPE PROJECT	2	0	0						50,000
			REHABILITATION/REPLACEMENT OF JSL IN CITY LIMITS				50,000	50,000	50,000	50,000	50,000	
						$ 271,878	$ 1,455,000	$ 1,411,500	$ 1,433,000	$ 1,485,000	$ 1,439,000	$ 5,706,000

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51-01301-	2730.04		**DEEP PUMP WELLS**									
01301	5132245	2015-0429	WELL ASSESSMENT AND UPGRADES	5	5	100,000	200,000	200,000	200,000	200,000	200,000	
01301	5132270	2015-0430	WELL BUILDING STRUCTURE UPGRADES	5	5	100,000	100,000	100,000	100,000	100,000	100,000	
01301	5132268	2015-0213	MP3.4 - 4TH AVENUE WELL ELECTRICAL IMPROVEMENTS	5	5	393,481	3,000,000					
01301	5132269	2015-0212	MP3.4 - 4TH AVENUE WELL/BRICK TANK IMPROVEMENTS	5	5	71,155						
01301	51322336	2015-0171	WELL TREATMENT PROJECT - 1500 EAST WELL	4	4	100,000	100,000					
01301		2016-0820	DYERS INN	4	4	0			550,000			
01301		2017-2071	DYER'S INN WELL FLUSH LINE	4	4	0			100,000			
01301		2016-0911	1300 E WELL CHLORINATION	3	4	0						400,000
01301		2015-0408	1300 EAST WELL FLUSH LINE	2	2	0			95,000			
01301	5132255	2015-0571	ARTESIAN WELL 2 REHAB	4	0	0						250,000
01301	5132249	2015-0565	19TH AND 27TH SOUTH WELL - VFD	3	0	0						60,000
01301	5132246	2015-0570	TREATMENT OF PCE AT WELLS	3	0	0						12,000,000
01301	5132241	2015-0569	RED BUTTE	2	0	0			2,500,000	60,000		2,500,000
01301	513223419		MT OLIVET IRRIGRATION FEASIBLITY STUDY			3,464						
01301		2018-1038	4TH AVENUE WELL INSPECTION	4	2	0						40,000
01301		2018-1091	VAN WINKLE PROPERTY FENCE	1	5	0					20,000	
						$ 768,100	$ 3,400,000	$ 300,000	$ 3,545,000	$ 360,000	$ 320,000	$ 15,250,000
51-01301-	2730.06		**STORAGE RESERVOIRS**									
01301	5134506	2017-1290	MOUNTAIN DELL RESERVOIR SEDIMENT SAMPLING AND BASIN PRE DESIGN	5	4	1,588						
01301	5134510		PARLEY'S DIVERSION STRUCTURE - IMPROVE BOOM DEPLOYMENT LOCATION	5	3	5,000						
01301	5134476		CHEVRON OIL SPILL PROTECTION PROJECT			3,000						
01301	5134458	2015-0155	REHABILITATION OF MOUNTAIN DELL DAM	5	4	853,333	2,165,000					
01301	5134455	2015-0167	RED PINE DAM REHABILITATION	5	4	30,000						484,000
01301	5134467	2015-0154	MOUNTAIN DELL RESERVOIR - BYPASS PIPE LITTLE DELL TO PARLEY'S	5	0	1,003,384						
01301	512450071	2017-2094	NEW ACTUATORS FOR THE PARLEYS CREEK DIVERSION STRUCTURE	5	0	17,714						
01301	5134468	2015-0607	LITTLE DELL RESTORE PARLEY'S DIVERSION EXTERIOR COATING	4	4	4,725						
01301	5124512	2015-0209	REPLACE VALVES ON MT. DELL DAM	4	4	0						320,000
01301	512700001	2017-2080	REABILITATION OF THE LAKE MARY GAUGE	3	5	1,161						
01301	512700005	2016-1272	CECRET DAM REHABILITATION - DESIGN	4	3	32,525						2,000,000
01301	512700002	2017-2082	REPAIRS TO TWIN LAKES DAM GAUGE	3	4	1,545						
01301	512700003	2017-2079	REPAIRS AND IMPROVEMENTS TO RED BUTTTE DAM ROAD	3	4	30,000						
01301	5134478	2015-0164	LITTLE DELL DAM - INSTALL NEW DRAINS ON THE PORTAL	3	3	0						27,000
01301		2016-1278	SECURITY CAMERAS AT LITTLE DELL	3	3	0						50,000
01301	5134457	2015-0166	NEW STAFF GAGE AT LITTLE DELL DAM	3	3	0						153,000
01301	5124509	2015-0451	STAIRS MT DELL DAM	2	3	0						75,000
01301		2015-0208	CONDUIT FROM DAM TO OLD ICB TO PLANT	2	2	0						20,000
01301	5134466	2015-0156	PARLEY'S CANYON HYDROPOWER PROJECT	1	0	0	100,000	900,000	200,000			
01301	512700006		LITTLE DELL PENSTOCK: PHASE 2			1,000,054						
01301		2018-1034	SPILL PROTECTION PROJECT - I-80 AT LAMB'S CANYON	5	0	0						240,000
01301		2018-1100	LAKE MARY DAM CREST REHABILITATION	5	5	0	20,000					100,000
01301		2018-1101	TWIN LAKES DAM GAUGE RELOCATION	3	4	0						20,000
01301		2018-1102	TWIN LAKE AND LAKE MARY OUTLET CHANNEL IMPROVEMENTS	5	5	0	15,000	50,000	50,000			
01301		2018-1103	PARLEYS CANYON CONDUIT AND FIBER INSTALLATION	4	0	0	100,000					100,000
01301		2018-1104	TWIN LAKES DAM DRAIN CLEANOUT INSTALLATION	4	5	0	40,000					40,000
01301		2018-1105	TWIN LAKES AND LAKE MARY LOG BOOMS	3	5	0						10,000
01301		2018-1106	MOUNTAIN DELL DAM SPILLWAY REHABILITATION	5	4	0	100,000					100,000
01301		2018-1107	LITTLE DELL DAM RODENT ERADICATION	4	4	0	50,000					30,000
01301		2018-1108	LITTLE DELL DAM STAFF GAUGE	3	0	0						175,000
01301		2018-1109	CECRET LAKE FLOW METER AND TELEMETRY	4	0	0						60,000
						$ 2,984,028	$ 2,590,000	$ 950,000	$ 250,000	$ -	$ -	$ 4,004,000

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51-01301-	2730.07		DISTRIBUTION RESERVOIRS									
01301	513444163	2017-2060	NEFF'S TANK OVERFLOW DRAIN	5	5	81,064						
01301	513444164	2017-2067	MARCUS RESERVOIR TANK UPGRADES	5	5	7,500						1,000,000
01301	513444161	2017-2074	EASTWOOD NORTH - INTERIOR COATING	5	5	128,632						
01301	513444162	2015-0527	FERGUSON TANK UPGRADE	5	5	14,511	150,000					
01301	513444166	2015-0573	AM - TANK AND RESERVOIR INSPECTIONS AND REPAIRS	5	5	100,000	100,000	100,000	100,000	100,000	100,000	100,000
01301	513444165	2015-0409	MOUNT OLYMPUS TANKS DRAIN/OVERFLOW STRUCTURE	5	4	72,580						
01301	5134507	2016-1171	FORT DOUGLAS IMPROVEMENTS/EXPANSION	5	4	163,424		4,000,000				1,500,000
01301	513444159	2015-0174	MILITARY RESERVOIR REPAIR	5	3	0						11,020,000
01301		2015-0406	EMIGRATION TUNNEL POWER	4	4	0						45,000
01301	513444168	2017-2111	TANNER RESERVOIR ROOF REPLACEMENT/FULL REPLACEMENT	4	4	6,800	100,000	1,000,000				
01301		2015-0719	DISTRIBUTION TANK AND RESERVOIR PAVING	4	4	0	80,000	80,000	80,000	80,000	80,000	
01301		2016-0753	BASKIN OVERFLOW/DRAIN GOOSENECK BOX	4	4	0			100,000			
01301		2017-2061	TETON TANKS SLOPE STABILIZATION	4	3	0		50,000				
01301		2015-0525	PERRY HOLLOW TANK	2	5	0	65,000					
01301	5134471	2015-0459	TANK PAINTING AND CORROSION CONTROL	3	3	100,000	200,000	200,000	200,000	200,000	200,000	
01301		2016-0935	ENSIGN DOWNS OVERFLOW	3	3	0						150,000
01301		2015-0516	MOUNT OLYMPUS TANKS & PUMP STATION BLACKTOP	2	4	0						25,000
01301		2015-0499	RAINER TANK	2	2	0						280,000
01301		2016-0917	ENSIGN DOWNS LOWER RESERVOIR MODIFICATIONS	2	2	0						200,000
01301		2015-0520	NORTH BENCH TANK ROAD	1	3	0						45,000
01301		2015-0526	VICTORY ROAD	1	3	0						22,000
01301		2016-0754	CAPITOL HILLS TANKS - TRUCK ACCESS	3	0	0						200,000
01301	513444167	2017-2121	TELFORD RESERVOIR SAFETY IMPROVEMENTS	1	2	1,234						
01301		2015-0528	NEFFS CANYON TANK	1	3	0						55,000
01301		2015-0529	EMIGRATION TANK UPGRADES	1	2	0						60,000
01301		2015-0530	TETON TANK UPGRADES	1	2	0						35,000
01301		2015-0458	MISCELLANEOUS REPAIRS	3	2	0			50,000			
01301		2017-2010	COVE TANK STABILIZATION PROJECT	2	3	0			200,000			
01301		2017-2012	TELFORD FENCE	3	0	0					30,000	
01301		2017-2013	EAST BENCH TANKS DRAIN LINE GOOSENECK	1	3	0					25,000	
01301		2017-2059	VICTORY ROAD TANK OVERFLOW DRAIN	4	4	0		50,000				
01301		2017-2064	CARRIGAN COVE TANK POWER	2	3	0				50,000		
01301		2017-2112	GRANITE OAKS/TELFORD RESERVOIR REPAIRS	3	3	0			50,000			
01301		2017-2118	GRANITE OAKS ACCESS ROAD	1	4	0			100,000			
01301		2018-1023	BASKIN RESERVOIR EFFLUENT PIPE	4	4	0		500,000				
01301		2018-1024	BASKIN ROOF REPLACEMENT	5	5	0	50,000					
01301		2018-1026	TANK AND RESERVOIR FALL PROTECTION SYSTEMS	5	0	0	100,000					
01301		2018-1031	MILITARY RESERVOIR - JOINT SEALANT REPAIR	5	4	0		20,000				
01301		2018-1032	MILITARY RESERVOIR - REPAIR INLET/OUTLET PIPE	5	4	0		50,000				
01301		2018-1033	MILITARY RESERVOIR CONDITION ASSESSMENT	5	4	0		20,000				
01301		2018-1092	FENCE 300 EAST GORDON LANE	1	4	0				5,000		
						$ 675,745	$ 845,000	$ 6,070,000	$ 880,000	$ 435,000	$ 435,000	$ 14,737,000
51-01301-	2730.08		DISTRIBUTION MAINS & HYDRANTS									
			CITY, COUNTY, STATE AND MISC. DRIVEN PROJECTS									
01301	513505272	2016-1233	WATER MAIN REPLACEMENT - 900 SOUTH	5	5	0	800,000					
01301	513505273	2016-0744	1300 EAST - WATER LINE	3	4	2,417,148						
01301	513505312	2015-0431	CITY/COUNTY/STATE DRIVEN PROJECTS	5	5	250,000	350,000	350,000	350,000	350,000	350,000	
01301		2016-1264	NW QUADRANT (DEVELOPMENT) PIPE UPSIZE	5	5	0						1,400,000
01301	513600099	2017-2056	ENERGY EFFICIENCY/RENEWABLE ENERGY CAPITAL IMPROVEMENTS	5	5	200,000	200,000	200,000	200,000	200,000	200,000	

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01301	513505308	2015-0398	UPPER CONDUIT METER REPLACEMENT	4	5	50,000						
01301	513600097	2017-2014	MOTORS AT WORK	4	4	16,000						
01301	513505230	2015-0245	EAST INDIANA AVENUE (850 SOUTH) - REDWOOD RD TO SURPLUS	3	5	149,072	985,000					
01301	513505332		CITY CREEK WATER MAIN VAULT REMOVAL			25,000						
01301		2018-1081	STATE IPS RESOLUTIONS	4	4	0	20,000	20,000	20,000	20,000	20,000	
01301	513505334		STATE "BETTERMENT" PROJECT, WATER LINE CROSSING 5600 WEST AT 1100 SOUTH			0	72,600					
01301			STATE 1100 SOUTH, 5600 WEST TO LEGACY VIEW (ABOUT 5700 W)			0	25,000					
			700 WEST - 1600 SOUTH TO 2100 SOUTH				100,000					
			LOCAL STREET DISTRICT 1 & 7				200,000					
			800 WEST - 600 SOUTH TO 800 SOUTH				350,000					
			500 EAST - 1700 SOUTH TO 2100 SOUTH				950,000					
			2000 EAST - PARLEY'S TO CITY LIMIT				300,000					
			1900 EAST - WILMINGTON TO PARLEYS CANYON				250,000					
			900 SOUTH - 900 WEST TO 900 EAST				5,000,000					
			300 WEST - 600 SOUTH TO 2100 SOUTH				2,500,000					
			LOCAL STREETS DISTRICT 3 & 6					200,000				
			900 EAST - HOLLYWOOD TO 2700 SOUTH					340,000				
			100 SOUTH - NORTH CAMPUS DRIVE TO 900 EAST					390,000				
			1700 EAST - 1700 SOUTH TO 2700 SOUTH					60,000				
			LOCAL STREETS DISTRICTS 2 & 5						200,000			
			200 SOUTH - 400 WEST TO 900 EAST						4,000,000			
			1100 EAST HIGHLAND , RAMONA TO WARNOCK							1,000,000		
			LOCAL STREETS DISTRICT 4 & 7							200,000		
			1100 EAST - 900 SOUTH TO RAMONA							4,000,000		
			300 NORTH - 300 WEST TO 1000 WEST							1,500,000		
			W TEMPLE - NORTH TEMPLE TO 400 SOUTH								800,000	
			LOCAL STREETS 3 & 6								200,000	
			VIRGINIA STREET - SOUTH TEMPLE TO 11TH AVE								100,000	
			1300 EAST - 2100 SOUTH TO 3000 SOUTH									
			2100 SOUTH - 700 EAST TO 1700 EAST									2,500,000
			LOCAL STREETS DISTRICT 1, 4 & 5									200,000
			GLADIOLA STREET - 900 SOUTH TO CALIFORNIA									50,000
			300 WEST - 400 SOUTH TO 900 SOUTH									2,000,000
			WAKARA WAY - FOOTHILL DRIVE TO CHIPETA WAY									150,000
						$ 3,107,220	$ 12,102,600	$ 1,560,000	$ 4,770,000	$ 7,270,000	$ 1,670,000	$ 6,300,000
			WATER MAIN MISCELLANEOUS PROJECTS									
01301	514500020	2015-0491	REGULATOR REPLACEMENT	5	5	20,000	300,000	300,000	300,000	300,000	300,000	
01301	513302118	2015-0493	NEW MAINLINE VALVES - COUNTY	5	5	138,000	138,000	138,000	138,000	138,000	138,000	
01301	513505311	2015-0489	NEW WATER LINES - CONTRIBUTIONS BY DEVELOPERS	5	5	500,000	500,000	500,000	500,000	500,000	500,000	
01301	513505310	2015-0490	FIRE HYDRANT REPLACEMENTS	5	5	400,000	400,000	400,000	400,000	400,000	400,000	
01301	513505309	2015-0492	NEW MAINLINE VALVES - CITY	5	5	262,000	262,000	262,000	262,000	262,000	262,000	
01301	513505304	2018-1002	UPPER CONUIT - LINE SYPHON	5	4	329,549	3,000,000					
01301	514500019	2016-0961	4TH AND A PRV	4	5	178,665						
01301		2016-0958	10TH AND B PRV	3	4	0		210,000				
01301		2016-0751	RECONNECTION OF 1700 SOUTH AND FOOTHILL UTILITIES	2	4	0			20,000			
01301	513600098	2017-2072	SAMPLING TAPS	3	3	50,000	10,000	10,000	10,000			
01301		2016-0923	SAM PARK INLET VAULT	3	3	0			35,000			
01301		2016-0959	10TH AND E PRV	3	3	0			210,000			
01301		2016-0960	8TH AND L PRV	3	3	0						210,000
01301		2016-0914	CONNECTIONS AT RR	4	0	0						440,000
01301	513600103		CORROSION CONTROL PROGRAM			47,653						
01301	514506		1000 EAST 500 SOUTH PRV			0	1,500,000					

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						$ 1,925,867	$ 6,110,000	$ 1,820,000	$ 1,875,000	$ 1,600,000	$ 1,600,000	$ 650,000
			WATER MAIN REPLACEMENTS									
01301	513505314		SMALL DIAMETER PIPE REPLACEMENT PROGRAM	5	5	250,000	250,000	250,000	250,000	250,000	250,000	
01301	513505203	2015-0247	600 WEST - 600 NORTH TO RAILROAD CROSSING	5	4	187,620						
01301	513505216		1000 NORTH - 1500 WEST TO REDWOOD ROAD	4	5	0	300,000					
01301	513302017	2015-0618	900 EAST AND 5600 SOUTH WATER MAIN REPLACEMENT	5	5	1,249				1,500,000		
01301	513302116	2016-0739	MILLCREEK WAY WATER MAIN REPLACEMENT	5	5	28,500	190,000					
01301	513505306	2017-2063	SCENIC DRIVE UPPER CONDUIT SLIPLINE PROJECT	5	5	0	300,000					3,000,000
01301	513505208	2015-0240	J STREET - SUNRISE AVENUE TO NORTHCREST DRIVE	5	4	492,260						
01301		2016-0921	BACKFEED FOR UTAH STATE CAPITOL	5	4	0		60,000				
01301		2016-1234	SHED AT EMIGRATION WELL	5	4	0			50,000			
01301	513505151	2015-0543	700 SOUTH - 300 WEST TO 700 WEST	5	4	0	630,000					
01301	513505156	2015-0233	200 SOUTH - 600 WEST TO JEREMY STREET	4	5	0	413,500					
01301	513505193	2015-0235	BECK STREET - 1805 NORTH TO 1180 NORTH	4	5	0						1,247,000
01301	513505207	2015-0252	3390 SOUTH - 700 EAST TO RIVIERA DRIVE	4	5	80,000	175,000					
01301	513504858	2015-0547	DULUTH AVE (1550 N) - 900 W TO DEXTER, 900 W - 1500 N TO DULUTH	4	5	1,688	175,000					
01301	513505130	2015-0549	FOOTHILL DRIVE - EMERSON AVE TO KENSINGTON AVE	4	5	0	105,000					
01301	513302047	2015-0617	MILLSTREAM DRIVE (3580 S) - MARDONNA WAY TO EASTWOOD DRIVE	4	5	0	274,000					
01301	513505133	2015-0624	1700 SOUTH - 1000 EAST TO 1100 EAST	4	5	0		160,000				
01301		2016-1230	17TH AND FOOTHILL TELEMETRY AND POWER	4	5	0			200,000			
01301		2015-0255	REDWOOD ROAD - 500 SOUTH TO 1050 SOUTH	4	5	0			918,000			
01301	513505212	2015-0253	PLEASANT VALLEY LINE	4	5	0						653,000
01301		2015-0254	CITY CREEK HIGHLINE	4	5	0						460,000
01301		2015-0554	SOUTH TEMPLE 1000 W.(GATSPY LINE)	5	3	0						415,000
01301	513505198	2015-0237	GREGSON AVENUE - 2465 EAST TO 2700 EAST	4	4	0						80,000
01301	513302089	2015-0238	2300 EAST - 6200 SOUTH TO 6400 SOUTH	4	4	0						268,000
01301	513505202	2015-0246	420 N MAIN STREET - 1" SERVICE REPLACEMENT - MAIN ST TO WALL ST	4	4	0						64,000
01301	513505125	2015-0260	WEST TEMPLE - 500 SOUTH TO 800 SOUTH (EAST SIDE)	4	4	0						469,000
01301	513505127	2015-0262	1000 WEST/1400 SOUTH WATER MAIN REPLACEMENT	4	4	0						560,000
01301		2017-2022	2880 SOUTH WATER MAIN REPLACEMENT	4	4	0						260,000
01301	513505197	2015-0236	800 SOUTH - 1200 EAST TO 1220 EAST	3	5	0						134,000
01301	513302039	2015-0613	OAK CREEK DRIVE - 8200 SOUTH TO END OF LINE	3	5	0						300,000
01301	513302045	2015-0616	MARDONNA WAY (3545 S) - SUNILAND DRIVE TO MILLSTREAM DRIVE	3	5	0						153,000
01301	513505128	2015-0620	WILTON WAY WATER MAIN REPLACEMENT	3	5	0						374,000
01301	513505129	2015-0621	1700 SOUTH - FOOTHILL TO WASATCH WATER MAIN REPLACEMENTS	3	5	0						257,000
01301	513505132	2015-0622	MILTON AVENUE (1595 SOUTH) - 1100 EAST TO 1200 EAST	3	5	0						179,000
01301		2017-2066	2700 E DEAD-END CONNECTION	3	5	0						20,000
01301		2016-0738	RELOCATE 12" CIP MAIN FROM UNDER HOUSE (EAST BENCH SUCTION LINE)	5	2	0						255,000
01301	513302090	2015-0239	COBBLECREST RD - 6380 S TO 2300 E; HAUN AVE - 2300 E TO COBBLECREST	4	3	0						411,000
01301		2015-0232	NORTH TEMPLE - 1800 WEST TO REDWOOD ROAD	4	3	0						156,200
01301	513505155	2015-0241	WESTMINSTER AVENUE - LAURELHURST (2550 EAST) TO FOOTHILL BOULEVARD (2600 EAST)	4	3	0						90,000
01301	513302038	2015-0258	BISCAYNE DR (2975 E) - BENGAL BLVD TO OAKVIEW CIR	4	3	0						158,000
01301	513505122	2015-0550	DUPONT AVE (1335 N) - AMERICAN BEAUTY DR TO 990 W	4	3	0						115,000
01301		2016-1228	REPLACE PRV'S - R11 AND R12	4	3	0						400,000
01301	513505205	2015-0249	SCOTT AVENUE - 700 EAST TO SCOTT PARK LANE	3	4	0						105,000
01301		2015-0400	R37. MAYWOOD REGULATOR	3	4	0						150,000
01301	513505134	2015-0625	BRYAN AVENUE (1565 SOUTH) - 900 EAST TO 1000 EAST	3	4	0						172,000
01301		2016-0889	CR1 PRV	3	4	0						225,000
01301		2016-0890	CR2 PRV	3	4	0						225,000
01301		2016-0891	HYDRANT 3300 SOUTH	3	4	0						40,000
01301		2016-0901	PRV E3-R49 REPLACEMENT	3	4	0						220,000
01301		2016-0910	HIGHLAND DRIVE REGULATORS	3	4	0						1,300,000

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01301		2016-0912	R73 REPLACEMENT	3	4	0						200,000
01301		2016-0913	CUP REGULATORS	3	4	0						300,000
01301		2016-0918	2300 EAST - CLAYBOURNE TO 3300 SOUTH	3	4	0						200,000
01301		2016-0934	PRV AT 17TH	3	4	0						210,000
01301		2016-1169	J STREET PIPELINE AND PRV REPLACEMENT	3	4	0						300,000
01301		2016-1273	NEW WATER MAIN - 1000 EAST	3	4	0						300,000
01301		2017-2062	ROXBURY PRV C46-R66	3	4	0						150,000
01301		2017-2065	CAMILLE ST. DEAD-END CONNECTION	3	4	0						20,000
01301		2016-1283	SUICIDE ROCK RUNAROUND	2	5	0						25,000
01301	513302117	2017-2069	CAP STUB AT 6200 SOUTH HOLLADAY BOULEVARD	3	3	2,250						
01301	513505124	2015-0619	BUCCANEER DRIVE WATER MAIN REPLACEMENT	3	3	0						151,000
01301		2016-0748	WATER VALVE REPLACEMENT PROJECT #3	2	4	0						100,000
01301	513505199	2015-0242	700 EAST - DRIGGS AVE (2370 S) TO WARNOCK AVE (2470 S)	1	5	0						257,000
01301		2015-0256	900 EAST HILLVIEW (4060 SOUTH) - REPLACE DIP MAIN UNDER SEWER	1	5	0						36,000
01301		2016-0756	300 WEST - 700 S TO 800 S	1	5	0						175,000
01301		2016-0892	KEARNS LINE REPLACEMENT	3	3	0						8,000,000
01301		2016-0900	R48 VALVE	3	3	0						20,000
01301		2016-0906	6-INCH ON 9TH	3	3	0						450,000
01301		2016-0915	SMITHS CONNECTION	3	3	0						70,000
01301		2016-0916	COUNTRY CLUB PRV	3	3	0						250,000
01301		2016-0933	MAYWOOD 6-INCH	3	3	0						220,000
01301		2016-0936	16-INCH VALVE VAULT	3	3	0						65,000
01301		2016-1222	PRV REPLACEMENT - A8-14	3	3	0						200,000
01301		2016-1231	NEW PRV - R73	3	3	0						200,000
01301		2016-1232	NEW PRV - R74	3	3	0						200,000
01301		2016-1235	POWER AT EMIGRATION TUNNEL	3	3	0						100,000
01301		2015-0399	RESEARCH PARK UPGRADE	5	0	0						410,000
01301		2016-0919	INSERTA VALVES	5	0	0						50,000
01301		2017-1299	EDWARD DRIVE REGULATED IMPROVEMENTS	5	0	0						500,000
01301		2017-2068	INDIAN ROCK PRESSURE ZONE REDUNDANT FEED	5	0	0						250,000
01301		2017-2070	HIGHLAND DR WATER MAIN - 6200 S TO DIAMOND HILLS LN	3	2	0						250,000
01301	513302046	2015-0615	SUNILAND DRIVE (3550 E) - MILLSTREAM LANE TO END OF SUNILAND CIRCLE	3	2	0						149,000
01301		2015-0426	FORT UNION AND HIGHLAND AVE INTERSECTION	2	3	0						302,500
01301		2017-2011	900 EAST FROM VAN WINKLE TO 5600 SOUTH	2	3	0						100,000
01301	513505204	2015-0248	500 SOUTH - 2130 WEST TO ORANGE STREET	4	0	0						315,000
01301	513302021	2015-0250	6200 SOUTH - 2900 EAST TO 3000 EAST	4	0	0						350,000
01301	513302058	2015-0544	SHORT HILLS DR (3375 E) - 8220 SOUTH TO 8315 SOUTH	4	0	0						55,000
01301		2015-0397	SUICIDE ROCK VAULT	2	2	0						100,000
01301		2016-0925	2700 E CONNECTION	2	2	0						60,000
01301		2015-0480	1700 EAST FROM FT UNION BLVD (6935 S) TO 7080 SOUTH	1	3	0						360,000
01301	513302059	2015-0548	3900 SOUTH - 900 EAST TO 940 EAST	3	0	0						130,000
01301		2015-0586	PARLEY'S CANYON BLVD 1700 EAST TO 1800 EAST	3	0	0						181,000
01301	513505166	2015-0626	400 EAST - 1497 SOUTH TO 1530 SOUTH	3	0	0						37,000
01301	513505167	2015-0627	1400 EAST - GILMER AVENUE TO YALE AVENUE	3	0	0						32,000
01301		2016-0957	MORRIS PUMP STATION	3	0	0						600,000
01301		2016-1168	KEARNS VALVE	3	0	0						30,000
01301		2015-0413	700 NORTH 8" AC	2	1	0						115,000
01301		2015-0641	LITTLE COTTONWOOD CREEK CEMENT CAP 4"	1	2	0						35,000
01301		2015-0407	2200 WEST WATER MAIN EXTENSION	1	0	0						255,000
01301	514000040		ASPHALT PATCHING 2018			30,000						
01301		2018-1096	CHEYENNE STREET WATER LINE REPLACEMENT	3	4	0			50,000			
01301		2016-0856	7000 SOUTH SAND TRAP AND SCREEN REMOVAL	5	5	0		20,000				
01301		2018-1041	UPPER BOUNDARY SPRINGS EFFLUENT LINE REPLACEMENT FROM SPRING BOX TO TANK	4	5	0		500,000				
01301		2017-2018	DULUTH AVE AND 900 WEST WATER MAIN REPLACEMENT	3	5	0	325,000		400,000			

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01301		2017-2110	DEVELOPER DRIVEN PROJECTS	4	4	0	100,000					
01301		2018-1079	2100 SOUTH, 700 EAST TO 1300 EAST, WATER LINE REPLACEMENT	3	4	0		1,800,000				
01301		2018-1089	EAST BENCH SUCTION LINE RELOCATION	4	2	0			96,400			
						$ 1,073,567	$ 3,237,500	$ 2,790,000	$ 1,964,400	$ 1,750,000	$ 250,000	$ 29,780,700
			MASTER PLAN PROJECTS									
01301	513416337	2015-0629	MP3.16 - NORTH BENCH PUMP STATION	5	5	15,065			1,500,000			
01301	513505088	2015-0217	CITY CREEK TREATMENT LINE TO MORRIS RESERVOIR	5	4	0	80,000		800,000			
01301	513302020	2015-0230	3RD EAST PHASE II - MARCUS TO ARTESIAN BASIN	4	4	266,503	4,000,000					
01301	51360062	2015-0632	MP2.3 - WASTEWATER REUSE	4	3	0						23,000,000
01301	513505116	2015-0633	MILLCREEK TREATMENT PLANT LINE - TANK TO WASATCH BLVD (24")	4	3	0						750,000
01301	513416327	2015-0218	MP 3.5B - 16" PIPELINE ON NEWPORT WAY/NANTUCKET DRIVE	4	2	0						394,000
01301	513302063	2015-0224	MP 3.5A - 12" PIPELINE ON HIGHLAND DR (6200 S HIGH ZONE)	3	3	0						317,000
01301		2015-0229	MP 3.17 - 8" LOOP AT 2200 WEST/2200 NORTH	5	0	0						948,000
01301	513505159	2015-0222	MP3.14 - AUXILIARY POWER - GOLDEN HILLS	5	0	0						45,000
01301	513505168		CAPITOL HILL TO ENSIGN DOWNS PIPELINE	4	0	0						5,000,000
01301	513302062	2015-0219	MP3.9 - NEW PUMP STATION - TETON TO MT. OLYMPUS/4500 SOUTH HIGH - IF	4	0	0						695,000
01301	513302061	2015-0220	MP3.6B - 12" PIPELINE ON BRIGHTON WAY	4	0	0						200,000
01301	513505117	2015-0221	MP3.5C - 16" PIPELINE ON BENGAL BOULEVARD	4	0	0						1,134,000
01301	513505098	2015-0225	MP3.1A - EAST-WEST CONVEYANCE LINE - PARK RESERVOIR TO SUGARHOUSE PARK	4	0	299,181	10,000,000	10,000,000				
01301		2015-0231	MP 3.8C - VICTORY ROAD - ENSIGN DOWNS PHASE II - IF	4	0	0						2,250,000
01301	5134493	2015-0634	MP3.1B - EAST WEST CONVEYANCE LINE - SUGARHOUSE PARK TO 900 WEST	4	0	0						7,000,000
01301	5134464	2015-0227	MP3.7 - ADD THROTTLING CONTROL VALVE INTO WILSON RESERVOIR	3	0	0						150,000
01301		2015-0538	MP 3.12A - 7800 SOUTH PRESSURE ZONE - 4.3 MG RESERVOIR	2	0	0						3,000,000
01301	51360060	2015-0636	MP2.1 - DEVELOP ADDITIONAL GROUND WATER SOURCES	2	0	0						18,000,000
01301	513505169	2015-0630	MP2.2 - ADDITIONAL SURFACE WATER DEVELOPMENT	2	0	0						12,000,000
01301	51360061	2015-0635	MP3.1C - EAST WEST CONVEYANCE LINE - 900 WEST TO 3400 WEST (PHASE 3)	1	0	0						12,000,000
01301		2015-0631	MILLCREEK WATER TREATMENT FACILITY	1	0	0						80,000,000
01301			UPDATE WATER MASTER PLAN			0			400,000			
						$ 580,749	$ 14,080,000	$ 10,000,000	$ 2,700,000	$ -	$ -	$ 166,883,000
			TOTAL DISTRIBUTION MAINS & HYDRANTS			$ 6,687,404	$ 35,530,100	$ 16,170,000	$ 11,309,400	$ 10,620,000	$ 3,520,000	$ 203,613,700
	2730.09		**WATER SERVICE CONNECTIONS**									
03301	513900116	2015-0534	2700 EAST - RELOCATE SERVICE CONNECTIONS	3	3	7,227						
01701	513900126	2015-0494	SERVICE LINE REPAIR/REPLACEMENTS	5	5	1,800,000	1,800,000	1,800,000	1,800,000	1,800,000	1,800,000	
03301	513900125	2015-0495	NEW SERVICE CONNECTIONS	5	5	400,000	400,000	400,000	400,000	400,000	400,000	
02201	513900124	2015-0496	LARGE METER REPLACEMENTS	5	5	400,000	400,000	400,000	400,000	400,000	400,000	
02601	513900123	2015-0498	METER REPLACEMENT PROGRAM	5	5	200,000	200,000	200,000	200,000	200,000	200,000	
	513900120		AMI TOWERS - CITY	4	0	97,219						
	513900121	2017-2122	AMI TOWERS - COUNTY	4	0	123,711						
	513900122	2017-2126	AMI METER REPLACEMENT PROGRAM	1	0	3,100,000	3,100,000	3,100,000	3,100,000	3,100,000	3,100,000	
						$ 6,128,156	$ 5,900,000	$ 5,900,000	$ 5,900,000	$ 5,900,000	$ 5,900,000	$ -
	2730.20		**LANDSCAPING**									
			WATERSHED									
00601	5122672	2017-1295	RECREATION AREA PICNIC TABLE REPLACEMENT	5	5	3,750						
00601	5122673	2015-0670	ACCESSIBILITY UPGRADES TO WATERSHED RECREATION FACILITIES	5	0	38,069		200,000		200,000		
	512627466	2017-2032	SILVER LAKE RESTROOM DEMOLISH AND REPLACE	5	5	290,784						

WATER UTILITY CIP BUDGET
Five Year Projected Budget FY2020-2024

COST CENTER	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	CRITICALITY RATING	CONDITION RATING	PAST YEAR SPENT 2018-19 (Calc'd from P6)	BUDGET YEAR 2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
00601	512627463	2017-1296	BIG COTTONWOOD CANYON PARK & RIDE RESTROOM REBUILD	5	5	0		500,000				
	514700004	2017-2117	CITY CREEK ROADWAY ASPHALT	5	5	0	100,000	100,000				
03201	51360014	2015-0519	WEST TEMPLE CAMPUS - CONSERVATION IMPROVEMENTS	2	4	11,250						
		2018-1028	CITY CREEK CANYON ROAD RECONSTRUCTION	5	5	0			500,000	1,000,000	1,000,000	1,000,000
		2018-1110	SITE 30 PAVILION STRUCTURAL REVIEW	2	4	0	20,000					
			CITY CREEK WATER SYSTEM TO SITES 23 THROUGH 30									500,000
						$ 343,852	$ 120,000	$ 800,000	$ 500,000	$ 1,200,000	$ 1,000,000	$ 1,500,000
			TOTAL CAPITAL IMPROVEMENTS			$ 24,629,211	$ 59,255,100	$ 53,501,500	$ 38,542,400	$ 42,350,000	$ 29,914,000	$ 596,995,700

WATER UTILITY CAPITAL PURCHASES BUDGET
Five Year Projected Budget FY2020-2024

COST CENTER	OBJECT CODE	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	Comments	CRITICALITY RATING	CONDITION RATING	PAST YEAR BUDGET 2018-19	BUDGET YEAR 2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
	2710.10			**LAND**										
5103301	2710.10		2015-0427	WATERSHED PROPERTY		5	0		1,500,000	1,500,000	1,500,000	1,500,000	1,500,000	1,500,000
5103301	2710.10		2015-0481	1811 WEST 500 SOUTH		5	5							
5103301	2710.10			2668 EAST COMANCHE DRIVE										
5103301	2710.10			983 N PINECREST CANYON ROAD EMIGRATION CANYON										
5103301	2710.10		2015-0172	MP 3.8C - VICTORY ROAD - ENSIGN DOWNS PHASE II - PI		4	0	590,737						
								$ 590,737	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000
	2710.30			**WATER RIGHTS & SUPPLY**										
5103301	2710.30			2,552 SHARES HILL DITCH @ $475				1,212,200						
5103301	2710.30			Various					30,000	30,000	30,000	30,000	30,000	
5103301	2710.30		2015-0488	56 SHARES UPPER CANAL IRRIIGATION @ $400		2	2	22,400						
								$ 1,234,600	$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ -
	2750.10		Replace No.	**AUTOMOBILES & TRUCKS**										
5100101	2750.10		New	Ford F550 1 Ton C&C w/Bed Cost Center				49,000						
5100601	2750.10		31136	CHEVROLET 3/4 TON PICK-UP TRUCK				28,961						
5100601	2750.10			2019 F350 CHASSIS XL 4X4 SD				31,640						
5100601	2750.10			SNOW PLOW				4,908						
5100601	2750.10			RUGBY DUMP BODY				7,858						
5100701	2750.10			UTV - Brutis				29,007						
5100701	2750.10			FORD F-350 CREW CAB 4X4 SHORT BED				31,299						
5100701	2750.10			SNOW PLOW				4,520						
5100701	2750.10			SALT SPREADER				4,804						
5100801	2750.10		31117	GMC 3/4 Ton Cab-n-Chassis Flat Bed to Plow				44,195						
5101301	2750.10		31068	ESCAPE SUV 4X4				22,507						
5101301	2750.10			INSPECTION VEHICLES (2)				60,575						
5101301	2750.10			2018 FORD FOCUS ELECTRIC 4DR				28,287						
5101401	2750.10		31016	Chevrolet 3/4 Ton Pick-up Truck w/ Lift Gate				37,831						
5101401	2750.10		31005/31006/31009	3/4 P U/ replace w/1/4 Ton Pick-up 2wd (3)				66,483						
5101401	2750.10		31095/31096	3/4 Ton Cab-n-Chassis w/Util. Bed 4wd ext Cab (2)				68,780						
5101601	2750.10		31112	REPLACEMENT FOR SURVEY VEHICLE 31112	Sell			57,922						
5101601	2750.10		31130	GMC 1/4 TON PICK-UP TRUCK				24,230						
5101701	2750.10		31115/31116/NEW	INTERNATIONAL V&H TRUCKS 7400 4X2 (3)				439,158						
5101701	2750.10		New	Freightliner Dump Truck				138,378						
5101701	2750.10		New	Escape SUV				22,507						
5101801	2750.10		31134	GMC Canyon				28,961						
5102101	2750.10		31082	CHEVROLET 1/4 TON PICK-UP TRUCK				22,161						
5102601	2750.10		31128	GMC 3/4 Ton Pick-up Truck				29,637						
5102601	2750.10		New	GMC 1 Ton Pick-up Truck				36,515						
5102801	2750.10		36960	GMC 1/4 TON PICK-UP TRUCK				28,961						

WATER UTILITY CAPITAL PURCHASES BUDGET
Five Year Projected Budget FY2020-2024

COST CENTER	OBJECT CODE	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	Comments	CRITICALITY RATING	CONDITION RATING	PAST YEAR BUDGET 2018-19	BUDGET YEAR 2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
5101301	2750.10			CHEV OR SIMILAR MID-SIZED 4X4 PICK UP W/	Jason				30,000					
5101301	2750.10			CHEV OR SIMILAR MID-SIZED 4X4 PICK UP W/	Jason				30,000					
5102601	2750.10		31128	4X4 1/2 TON VXU W/CAMPER SHELL					27,000					
5102601	2750.10		31146	1/4 TON					25,000					
5102601	2750.10		36950	1 TON NON-DUMPING FLAT BED					37,000					
5102601	2750.10		31204	CHEVY COLORADO 4WD					29,500					
5100901	2750.10		31281	FORD F-150 4WD	Marian				35,000					
5101801	2750.10		31134	COLORADO 4WD	Marian				30,000					
5101801	2750.10		31177	CHEVY COLORADO 4WD	Marian				30,000					
5100701	2750.10		NEW	1/4 TON 4WD, EXTENDED CAB, POWER WIND	Marian				30,000					
5100601	2750.10		NEW	1/4 TON 4WD, EXTENDED CAB, POWER WIND	Marian				30,000					
5100601	2750.10		NEW	1/4 ton, 4-wheel Drive, extended cab, power wind	Marian				40,000					
5100101	2750.10		31087	Replace Ford F250, State contract	Randy				41,500					
5100101	2750.10		3703	John Deere 5100M W/Mower	Randy				79,265					
5102301	2750.10			VARIOUS						1,000,000	1,000,000	1,000,000	1,000,000	
								1,349,084	494,265	1,000,000	1,000,000	1,000,000	1,000,000	-
	2750.30			**FIELD MAINT EQUIPMENT - MOTIVE**										
5100101	2750.30			Link Belt 160 x 4 Excavator				180,000						
5100101	2750.30			S550 Slide in Ass'y (Masport H XL3 Direct Drive) Alum				11,161						
5101701	2750.30			Case Backhoe				92,616						
5101701	2750.30			BACKHOE EXCHANGE PROGRAM				81,000						
5101701	2750.30			Backhoe Trailer				28,375						
5102101	2750.30			Hyster Fork Lift				43,981						
5102201	2750.30			Interstate 50tdc Trailer				28,375						
5102301	2750.30			VARIOUS				95,500		50,000	50,000	50000	50000	
5102601	2750.30			HANDHELD READING UNITS (2)	Audree				17,232					
5101601	2750.30		31148	CHEVY/GMC 4X4 EXT CAP	Nick				30,000					
5101601	2750.30		31149	CHEVY/GMC 4X4 EXT CAP	Nick				30,000					
5101601	2750.30		31150	CHEVY/GMC 4X4 EXT CAP	Nick				30,000					
5101401	2750.30		80564	SKAGG SVRII-36A-19FX	Jason/Randy				9,550					
5100101	2750.30		NEW	CAT/WHEELER BUCKET - DC 60" DITCH	Jason/Randy				5,400					
5101601	2750.30			KUBOTA BX235 Mini-Tractor	Marian				25,000					
5101601	2750.30			Winter Tractor	Marian				28,000					
								561,008	175,182	50,000	50,000	50,000	50,000	-
	2760.10			**PUMP PLANT EQUIPMENT**										
5100801	2760.10			CLEAR WATER AND AREA DRAIN PUMPS				40,000						
5100801	2760.10			REPLACE EXISTING LMI CHEMICAL FEED PUMPS				9,537						

WATER UTILITY CAPITAL PURCHASES BUDGET
Five Year Projected Budget FY2020-2024

COST CENTER	OBJECT CODE	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	Comments	CRITICALITY RATING	CONDITION RATING	PAST YEAR BUDGET 2018-19	BUDGET YEAR 2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
5100801	2760.10			REPLACE VALVING MAINFOLD IN PUMP HOUSE				100,000						
5100901	2760.10			EQUALIZATION PUMP				19,455						
5100901	2760.10			WASTEWATER RETURN PUMP				13,492						
5101301	2760.10			VARIOUS				50,000	50,000	50,000	50,000	50,000	50,000	
								232,484	50,000	50,000	50,000	50,000	50,000	-
	2760.20			**TREATMENT PLANT EQUIPMENT**										
5100701	2760.20			FLOC BUSHING		4	4	30,000						
5100701	2760.20	5122631		SECURITY FENCE FOR SLUDGE BEDS/BACKWASH TANK		3	3	75,000						
5100701	2760.20	5122632		SECURITY FENCING FOR BACK OF PLANT		3	3	40,000						
5100701	2760.20			REPLACEMENT PARTICLE COUNTERS				24,000						
5100701	2760.20			TURBIDITY METERS				35,000						
5100701	2760.20			ON-DEMAND HOT WATER HEATERS										
5100801	2760.20			DR 6000-PHOTANALYZER (UV BULB)				8,000						
5100801	2760.20			CHLORINE ANALYZER				8,000						
5100801	2760.20			HEADLOSS METER				13,300						
5100801	2760.20	18		BACK-UP WATER SUPPLY FROM CLEARWELL TO HIGH PRESSURE TANK										
5100801	2760.20	5124508		PARLEY'S TP - REPLACE ALL POST STORAGE TANK HYP(		1	1							
5100801	2760.20			DR 6000-PHOTOANALYZER (UV BULB)				8,000						
5100801	2760.20			CHLORINE ANALYZER				8,000						
5100801	2760.20			HEADLOSS METER				13,300						
5100801	2760.20			FLYGT 4" SUBMERSIBLE PUMP MODEL CP3102.090				13,910						
5100901	2760.20			HYDROMATIC SUBMERSIBLE SOLIDS HANDLING PUMP				13,910						
5100901	2760.20			FLOC BUSHING		4	4	30,000						
5100901	2760.20			CAMERA UPGRADE BIG COTTONWOOD										
5100901	2760.20			ONLINE TURBIDITY METER				70,000						
5101301	2760.20			VARIOUS				100,000		100,000	100,000	100000	100000	
5100801	2760.20			SURFACE WASH PUMP	Marian				60,000					
								490,420	60,000	100,000	100,000	100,000	100,000	-
	2760.30			**TELEMETRY EQUIPMENT**										
5101501	2760.30			MISCELLANEOUS WATER TELEMETRY 2018/2019				50,000	50,000	50,000	50,000	50,000	50,000	
5101501	2760.30			Telemetry Equipment - Water Ongoing				50,000						
5101501	2760.30			CCTV Recorder - Dispatch				10,000						
5101501	2760.30		2017-1308	INSTALLATION OF NEW SNOW GAUGING STATIONS		4	0	60,000						
5100201	2760.30			TELEMETRY FOR TWIN LAKES										
								170,000	50,000	50,000	50,000	50,000	50,000	-
	2760.50			**OFFICE FURNITURE & EQUIPMENT**										
5103201	2760.50			SOFTWARE UPGRADE BILLING SYSTEM				30,000	30,000	30,000	30,000	30000	30000	
5101301	2760.50			Full Function Printer replacement "Engineering"				5,765						
5103301	2760.50			Full Function Printer replacement "Contracts"				5,765						
	2760.90			**OTHER NON-MOTIVE EQUIPMENT**				41,530	30,000	30,000	30,000	30,000	30,000	-

WATER UTILITY CAPITAL PURCHASES BUDGET
Five Year Projected Budget FY2020-2024

COST CENTER	OBJECT CODE	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	Comments	CRITICALITY RATING	CONDITION RATING	PAST YEAR BUDGET 2018-19	BUDGET YEAR 2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
5103201	2760.90			VARIOUS				50,000	50,000	50,000	50,000	50,000	50,000	
5101701	2760.90			EMERGENCY PIPING				50,000	50,000	50,000	50,000	50,000	50,000	
5102601	2760.90			HANDHELD METER READING DEVICES				20,000	20,000	20,000	20,000	20,000	20,000	
5100601	2760.90			WOOD CHIPPER				79,010						
5100601	2760.90			NEW 2018 MCLAUGHLIN VSK 25-100G VACUUM				18,965						
5101201	2760.90			TRAILER FOR SPILL RESPONSE AT DIVERSION				6,000						
5101201	2760.90			BOAT				5,000						
								228,975	120,000	120,000	120,000	120,000	120,000	-
				TOTAL CAPITAL OUTLAY				$ 4,898,838	$ 2,509,447	$2,930,000	$2,930,000	$2,930,000	$2,930,000	$1,500,000

Sewer Utility- Budget Summary and Cash Flow

SEWER UTILITY
ENTERPRISE FUND
BUDGET SUMMARY
FY 2020-22

SOURCES	ACTUAL 2017-18	AMENDED BUDGET 2018-19	PROJECTED ACTUAL 2018-19	Rate Increase 18% PROPOSED BUDGET 2019-20	Rate Increase 18% FORECAST BUDGET 2020-21	Rate Increase 18% FORECAST BUDGET 2021-22
REVENUES						
METERED SALES	$ 33,620,751	$ 37,677,666	$ 37,677,666	**$ 44,460,000**	$ 52,838,000	$ 62,791,000
INTEREST INCOME	1,579,221	1,052,000	$ 1,052,000	**604,000**	23,000	29,000
OTHER REVENUES	659,888	235,000	$ 235,000	**235,000**	235,000	235,000
TOTAL REVENUES	$ 35,859,860	$ 38,964,666	$ 38,964,666	**$ 45,299,000**	$ 53,096,000	$ 63,055,000
OTHER SOURCES						
IMPACT FEES	971,344	700,000	$ 700,000	**700,000**	724,500	749,858
GRANTS & OTHER RELATED REVENUES	978,525	2,020,000	$ 2,020,000	**2,020,000**	2,020,000	720,000
OTHER SOURCES	2,845	20,000	$ 20,000	**20,000**	20,000	20,000
STATE LOAN (NWQ)	-	-	$ -	**-**	-	-
NON BOND FINANCING	8,500,000	4,000,000	$ -	**-**	67,429,000	85,926,000
BOND PROCEEDS	-	-	$ -	**55,307,000**	39,218,000	97,542,000
T O T A L OTHER SOURCES	$ 10,452,714	$ 6,740,000	$ 2,740,000	**$ 58,047,000**	$ 109,411,500	$ 184,957,858
T O T A L SOURCES	$ 46,312,574	$ 45,704,666	$ 41,704,666	**$ 103,346,000**	$ 162,507,500	$ 248,012,858
EXPENSES & OTHER USES						
EXPENDITURES						
PERSONNEL SERVICES	$ 8,486,161	$ 10,375,345	$ 10,375,345	**$ 11,164,232**	$ 11,610,802	$ 12,075,232
OPERATING & MAINTENANCE	1,406,164	1,934,720	1,934,720	**2,109,430**	2,151,219	2,194,242
TRAVEL & TRAINING	48,179	86,900	86,900	**118,425**	120,794	123,209
UTILITIES	852,935	980,070	980,070	**994,970**	1,014,869	1,035,166
TECHNICAL SERVICES	1,831,306	3,291,348	3,291,348	**3,151,533**	3,327,843	3,394,400
DATA PROCESSING	381,234	280,000	280,000	**395,000**	402,900	410,958
FLEET MAINTENANCE	568,447	543,000	543,000	**543,000**	553,860	564,937
ADMINISTRATIVE SERVICE FEE	306,260	275,000	275,000	**311,000**	317,220	323,564
PAYMENT IN LIEU OF TAXES	306,525	368,250	368,250	**661,263**	674,488	687,978
BILLING COST	813,896	813,896	813,896	**827,634**	844,187	861,071
RISK MANAGEMENT	303,564	308,500	308,500	**260,324**	265,530	270,841
TRANSFERS TO GENERAL FUND	-	20,000	20,000	**-**	-	-
OTHER CHARGES AND SERVICES	50,100	148,588	148,588	**487,353**	496,676	506,611
TOTAL EXPENDITURES	$ 15,354,771	$ 19,425,617	$ 19,425,617	**$ 21,024,164**	$ 21,780,388	$ 22,448,209
OTHER USES						
CAPITAL OUTLAY	847,714	5,946,500	1,302,569	**8,694,000**	823,000	823,000
CAPITAL IMPROVEMENT BUDGET	33,243,806	116,640,041	60,892,051	**98,370,500**	125,728,000	210,160,000
COST OF DEBT ISSUANCE	7,200	15,000	-	**307,000**	218,000	542,000
DEBT SERVICES	5,554,277	6,058,000	6,050,603	**13,149,000**	13,399,000	13,776,000
T O T A L OTHER USES	$ 39,652,997	$ 128,659,541	$ 68,245,223	**$ 120,520,500**	$ 140,168,000	$ 225,301,000
T O T A L USES	$ 55,007,768	$ 148,085,158	$ 87,670,840	**$ 141,544,664**	$ 161,948,388	$ 247,749,209
EXCESS REVENUE AND OTHER SOURCES OVER (UNDER) USES	$ (8,695,194)	$ (102,380,492)	$ (45,966,174)	**$ (38,198,664)**	$ 559,112	$ 263,649
OPERATING CASH BALANCES						
BEGINNING JULY 1	$ 94,916,245	$ 86,221,051	$ 86,221,051	**$ 40,254,877**	$ 2,056,213	$ 2,615,325
ENDING JUNE 30	$ 86,221,051	$ (16,159,441)	$ 40,254,877	**$ 2,056,213**	$ 2,615,325	$ 2,878,974
Cash Reserve Ratio	562%	-83%	207%	**10%**	12%	13%

Cash reserve goal above 10%

+18%,18%,18%,15%,10% rates
$259M in WIFIA Funds
$283M in Bonds,$55M,$39M,$97M,$65M $27M
100% CIP FY 20-24
New Debt Pmts $44.9M FY 20-24

SEWER UTILITY
Cash Flow
FY20 Budget
and FY2020-2024 Forecast

	ACTUAL YEAR 2017-2018	PROJECTED YEAR 2018-2019	BUDGET YEAR 2019-2020	BUDGET YEAR 2020-2021	BUDGET YEAR 2021-2022	BUDGET YEAR 2022-2023	BUDGET YEAR 2023-24
SEWER SALES	$33,620,751	$37,677,666	$44,460,000	$52,838,000	$62,791,000	$72,718,000	$80,548,000
OTHER INCOME	662,733	255,000	255,000	255,000	255,000	255,000	255,000
INTEREST INCOME	1,579,221	1,052,000	604,000	23,000	29,000	31,000	30,000
OPERATING INCOME	35,862,705	38,984,666	45,319,000	53,116,000	63,075,000	73,004,000	80,833,000
NEW PLANT O&M COSTS			0	0		*(250,000)*	*(252,500)*
OPERATING EXPENSES	(15,354,771)	(19,425,617)	(21,024,164)	(21,780,388)	(22,448,209)	(23,138,679)	(23,852,612)
NET INCOME EXCLUDING DEP.	20,507,934	19,559,049	24,294,836	31,335,612	40,626,791	49,615,321	56,727,888
IMPACT FEES	971,344	700,000	700,000	724,500	749,858	776,103	803,267
STATE LOAN (NWQ)	8,500,000						
SHORT TERM FINANCING PROCEEDS							
WIFIA LOAN				67,429,000	85,926,000	65,057,000	31,865,000
NET BOND PROCEEDS	-		55,000,000	39,000,000	97,000,000	65,000,000	27,000,000
ISSUE COSTS (PROCEEDS)			307,000	218,000	542,000	363,000	151,000
ISSUE COSTS (EXP)	(7,200)		(307,000)	(218,000)	(542,000)	(363,000)	(151,000)
OTHER CONTRIBUTIONS	978,525	2,020,000	2,020,000	2,020,000	720,000	520,000	520,000
CAPITAL OUTLAY	(847,714)	(1,302,569)	(8,694,000)	(823,000)	(823,000)	(823,000)	(823,000)
STATE LOAN DEBT REPAYMENT			(6,375,000)	(2,125,000)			
NEW DEBT SERVICE			(719,000)	(2,700,000)	(5,216,000)	(9,091,000)	(12,731,000)
DEBT SERVICE	(5,554,277)	(6,050,603)	(6,055,000)	(8,574,000)	(8,560,000)	(8,561,000)	(8,935,850)
OTHER INCOME & EXPENSE	4,040,678	(4,633,172)	35,877,000	94,951,500	169,796,858	112,878,103	37,698,417
GENERATED FOR CAPITAL	24,548,612	14,925,877	60,171,836	126,287,112	210,423,649	162,493,424	94,426,305
CAPITAL IMPROVEMENTS	(33,243,806)	(60,892,051)	(98,370,500)	(125,728,000)	(210,160,000)	(162,630,000)	(94,660,000)
CASH INCREASE/(DECREASE)	(8,695,194)	(45,966,174)	(38,198,664)	559,112	263,649	(136,576)	(233,695)
		0					
BEGINING CASH BALANCE	94,916,245	86,221,051	40,254,877	2,056,213	2,615,325	2,878,974	2,742,398
CASH INCREASE/(DECREASE)	(8,695,194)	(45,966,174)	(38,198,664)	559,112	263,649	(136,576)	(233,695)
ENDING BALANCES	86,221,051.00	40,254,877.00	2,056,213	$2,615,325	$2,878,974	$2,742,398	$2,508,703
RESTRICTED/RESERVED	(10,789,378)						
AVAILABLE ENDING BALANCE	$75,431,673	$40,254,877	2,056,213	$2,615,325	$2,878,974	$2,742,398	$2,508,703
RATE CHANGE	30%	15%	18%	18%	18%	15%	10%
Cash Reserve Ratio	**562%**	**207%**	**10%**	**12%**	**13%**	**12%**	**10%**
Debt Service Coverage	**3.69**	**3.23**	**3.59**	**2.78**	**2.95**	**2.81**	**2.62**
DEBT SERVICE % OF GROSS OPERATING REV	**15%**	**16%**	**15%**	**21%**	**22%**	**24%**	**27%**
MONTHLY RESIDENTIAL UTILITY BILL AT 4 CC	**10.60**	**12.16**	**14.68**	**17.32**	**20.44**	**23.51**	**25.86**
MONTHLY RESIDENTIAL UTILITY BILL AT 8 CC	**21.20**	**24.32**	**29.36**	**34.64**	**40.88**	**47.01**	**51.71**

SEWER UTILITY CIP BUDGET
Five Year Projected Budget FY2020-2024

COST CENTER	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	CRITICALITY RATING	CONDITION RATING	PAST YEAR SPENT 2018-19 (Calc'd from P6)	BUDGET YEAR 2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
	2720.10		**MAINTENANCE & REPAIR SHOPS - 2720.10**									
		2016-0956	LIFT STATION STORAGE FACILITY	4	0	0			350,000			
						0	0	0	350,000	0	0	0
	2720.05		**LIFT STATIONS - 2720.05**									
			LIFT STATION ASSET MANAGEMENT PROGRAM									
10101	524907096		ANNUAL SYSTEM WIDE LIFT STATION SCOPING & ASSET MANAGEMENT PRIORITIZATION	5	5	200,000	200,000	200,000	80,000	80,000	80,000	320,000
			LIFT STATION RENEWAL/REPLACEMENT PROGRAM									
	52490788		LIFT STATION CONDITION ASSESSMENT (TASK ORDER 2.18)			10,938						
10101	524907095	2015-0414	ANNUAL PUMP REPLACEMENT (VARIOUS)	5	5	25,000	25,000	25,000	50,000	50,000	50,000	200,000
	52490758	2015-0266	4000 WEST LIFT STATION UPGRADE/REPLACEMENT (SS12)	5	5	911,983						
10101	52490780	2015-0263	1700 NORTH LIFT STATION REHABILITATION (SS03)	4	5	299,998						
10101		2017-1301	5300 WEST LIFT STATION (SS17) CAPACITY IMPROVEMENTS	4	5	0	75,000	430,000				
10101	52490778	2015-0264	SOUTH LIFT STATION (SS05)	3	4	0			65,000	365,000		
10101		2015-0417	INDUSTRIAL LIFT STATION REHAB & PIPING UPGRADES (SS21)	4	5	0	70,000	710,000				
10101		2015-0267	NEW ROSE PARK LIFT STATION REPLACEMENT (SS02)	4	5	0	40,000	320,000				
10101	2015-0268	2015-0268	500 W LIFT STATION WET WELL IMPROVEMENTS (SS28)	4	5	0	50,000	425,000				
10101		2015-0274	PIONEER LIFT STATION WET WELL IMPROVEMENTS (SS20)	4	4	0			60,000	570,000		
10101		2015-0418	CENTENNIAL LIFT STATION WET WELL REHABILITATION (SS 19)	4	4	0			70,000	650,000		
10101		2015-0271	CANNON LIFT STATION WET WELL IMPROVEMENTS	4	4	0			40,000	375,000		
10101		2015-0270	WESTPOINTE LIFT STATION WET WELL IMPROVEMENTS (SS 33)	3	3	0						550,000
10101		2015-0272	900 NORTH LIFT STATION WET WELL IMPROVEMENTS	4	5	0	50,000	450,000				
		2017-2008	BILLY MITCHELL (SS16) CAPACITY IMPROVEMENTS	3	4	0			60,000	750,000		
	524907093	2017-2075	HUSKY LIFT STATION		4	2,600,000						
						4,047,918	510,000	2,560,000	425,000	2,840,000	130,000	1,070,000
	2720.30		**TREATMENT PLANTS**									
11201	524905347	2015-0640	FACILITY BUILDING PAINTING (CORROSION PROTECTION PROGRAM)	5	5	100,000	100,000	100,000	100,000	100,000	100,000	400,000
	524905338	2017-2093	INFLUENT SCREEN (S) REPLACE/RETROFIT	5	5	712,728	3,200,000					
	524905336		EXISTING FACILITES CONDITION ASSESSMENT/PRE-DESIGN		5	75,000						
	525400075		SOUTH RAS SKIMMER RELOCATION		4	14,615						
	52540066		WETLANDS RESTORATION PROJECT		4	0						
	524905342		PROCESS CONTROL LAB ROOM		4	19,221						
		2016-1275	WASHER COMPACTOR FOR PRIMARY SLUDGE	4	0	0		250,000				
	525400074	2017-2088	SCADA INSTRUMENTATION CONTROL IMPROVEMENTS	5	5	0						
~~11201~~	524905330	2015-0707	CHLORINE BUILDING ALARM SYSTEM		5	210,000						
		2018-1074	SCADA PHASE III FOLLOW-UP SERVICES	5	5	0	400,000					
~~11201~~	524905280	2015-0710	REPLACEMENT OF MCC2A AT THE PRE-SEDIMENTATION BUILDING - CONSTRUCTION		5	575,531						
11201	52540053	2015-0708	ATMOSPHERIC MONITORING REPLACEMENT PROGRAM	5	5	19,537		25,000	25,000	25,000	25,000	100,000
	52540064		VFD REPLACEMENT		5	227,208						
11201	52540052	2015-0500	TRICKLING FILTER REHABILITATION	5	5	0	650,000					2,000,000

SEWER UTILITY CIP BUDGET
Five Year Projected Budget FY2020-2024

COST CENTER	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	CRITICALITY RATING	CONDITION RATING	PAST YEAR SPENT 2018-19 (Calc'd from P6)	BUDGET YEAR 2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
	52540067		TRICKLIKNG FILTER PUMPS INSPECTION & RECONDITIONING			117,229						
11201	524905345	2015-0502	CAPITAL ASSET REHABILITATION AND UPGRADES	5	5	1,300,000	1,300,000	1,300,000	1,300,000	1,300,000	1,300,000	5,200,000
11201	2016-1133	2016-1133	REHAB OF VERTICAL TURBINE PUMPS	4	4	0				200,000		400,000
11201	524905344	2017-2089	HVAC REPLACEMENTS	3	3	25,000		25,000	25,000	25,000	25,000	100,000
	524905341		HVAC IMPROVEMENTS AT PRE-SEDIMENTATION			6,938						
		2016-1281	COGEN ENGINE OVERHAUL									700,000
		2018-1052	SLC WRF HEADWORKS GATE REPLACEMENT	5	5	0	250,000					
	524905334	2016-1160	UPGRADE EMERGENCY GENERATORS AT PUMP STATION	4	5	0	50,000					
		2018-1072	SLC WRF INFLUENT PUMP MOTOR REBUILD	5	4	0	120,000					
		2018-1071	SLC WRF INFLUENT PUMP REBUILD	5	4	0	200,000					
		2018-1068	SLC WRF BIO GAS HEAT EXCHANGER	4	4	0	75,000					
		2018-1066	SLC WRF PUMP PLANT EXTERIOR LIGHTING	4	5	0	35,000					
			NEW WATER RECLAMATION FACILITY									
	524905271		NEW PLANT - CORE DESIGN/BUILD RECLAMATION FACILITY	5	0	0	1,750,000	10,250,000	5,000,000	3,500,000	2,000,000	400,000
	524905335		WRF MASTER PLAN IMPLEMENTATION - CAPITAL PROJECT SUPPORT	5	0	1,500,000	4,500,000	4,500,000	4,500,000	3,500,000	3,500,000	4,000,000
11201	524905271		NEW PLANT - MECHANICAL DEWATERING (CONSTRUCTION)	5	0	0	33,500,000	440,000				
			NEW PLANT - BNR LIQUID STREAM (CONSTRUCTION)	5	0	0		41,020,000	#########	120,360,000	15,960,000	
			NEW PLANT - SOLIDS HANDLING (CONSTRUCTION)	5	0	0					41,160,000	2,840,000
			NEW PLANT - ADMIN OPS (CONSTRUCTION)	5	0	0		14,090,000	1,620,000			
			NEW PLANT - DEMOLITION (CONSTRUCTION)	5	0	0						6,500,000
	525400068	2017-2050	NEW PLANT - PROFESSIONAL DESIGN SERVICES	5	0	12,459,510	9,500,000	7,800,000	7,500,000	5,100,000	2,100,000	3,000,000
	524905339	2017-2051	NEW PLANT - CM/GC DESIGN SERVICES	5	0	488	3,000,000	2,500,000	1,000,000			
	524905337	2017-2052	NEW PLANT - WATER RENEW PUBLIC OUTREACH	5	0	250,000	300,000	250,000	250,000	250,000	250,000	500,000
	524905340	2017-2054	NEW PLANT - PILOTING AND DEMONSTRATION TESTING	5	0	98,947	2,000,000	2,000,000				
			NEW PLANT - PROJECT DOCUMENTATION	4	0	0	150,000	60,000	60,000	60,000	60,000	120,000
11201	524905272	2015-0404	NEW WATER RECLAMATION FACILITY - INFLUENT SCREENINGS (CONSTRUCTION)		5	0						
			TOTAL NEW WATER RECLAMATION FACILITY				54,700,000	82,910,000	#########	132,770,000	65,030,000	17,360,000
			TOTAL WATER RECLAMATION FACILITY			17,711,954	61,080,000	84,610,000	176,810,000	134,420,000	66,480,000	26,260,000
	2730.14		**COLLECTION LINES**									
			COLLECTION SYSTEM ASSET MANAGEMENT PROGRAM									
10401	52510020	2015-0704	1200 WEST TRUNK LINE CONDITION ASSESSMENT/ PROJECT PRE-DESIGN	5	2	0						600,000
10401	525002742	2015-0664	SIPHON INSPECTION PROJECT	4	2	0					100,000	
10401	525002834	2015-0647	COLLECTION SYSTEM PROJECT DEVELOPMENT CAP SCOPING	5	5	100,000	150,000	150,000	100,000	100,000	100,000	400,000
10401	525002770	2015-0703	BECK STREET TRUNK LINE CONDITION ASSESSMENT/PRE-DESIGN	5	2	232,403						600,000
10401	525002771	2015-0705	ORANGE STREET TRUNK LINE CONDITION ASSESSMENT/PROJECT PRE-DESIGN	5	2	0						500,000
						332,403	150,000	150,000	100,000	100,000	200,000	2,100,000
			FLOW MONITORING/I&I PROGRAM									
10401	525002756	2015-0648	WEST SIDE INFLOW & INFILTRATION STUDY		5	151,004						
10401	525002741	2015-0651	ANNUAL HYDRAULIC MODEL CALIBRATION	4	2	0				100,000		300,000

SEWER UTILITY CIP BUDGET
Five Year Projected Budget FY2020-2024

COST CENTER	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	CRITICALITY RATING	CONDITION RATING	PAST YEAR SPENT 2018-19 (Calc'd from P6)	BUDGET YEAR 2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
10401	525002740	2015-0649	PERMANENT FLOW METERS	5	0	350,000		250,000	250,000	250,000		
			VARIOUS BASIN INFLOW TESTING		4	0						
						501,004	0	250,000	250,000	350,000	0	300,000
			CITY, COUNTY, STATE AND MISC. DRIVEN PROJECTS									
10401	525002738	2015-0654	PRISON RELOCATION UTILITIES AND DEVELOPMENT SUPPORT		5	330,263						
	525002674		TERMINAL REDEVELOPMENT PROJECT	5	0		5,000	5,000				
10401	525002560	2015-0484	ANNUAL MISC. PUBLIC SERVICES PROJECTS	5	5	200,000	200,000	200,000	200,000	200,000	200,000	1,000,000
10401	525002738	2016-1262	NW QUADRANT CF INFRASTRUCTURE SUPPORT SERVICES	5	5	330,263	400,000	350,000				
	525002760		WEST TEMPLE - NORTH TEMPLE TO 400 SOUTH	4	5	673,778						
10401	525002764	2016-0743	1300 EAST - SEWER		5	285,900						
10401	2016-1265	2016-1265	NW QUADRANT (DEVELOPMENT) PIPE UPSIZE SEWER	5	0	0	350,000					
10401	525002681		WILMINGTON AVENUE SANITARY SEWER			15,082						
10401			MOUNTAIN VIEW CORRIDOR UDOT BETTERMENT			0	250,000					
			ODOR & CORROSION PRELIMINARY DESIGN AND SITING ANALYSIS	5	5	0	350,000					
			ODOR & CORROSION IMPLEMENTATION PROGRAM	5	0	0	50,000	1,500,000	1,500,000	1,500,000	1,500,000	4,500,000
			900 S (950 E TO 1300 E) ROADWAY	5	5	0	600,000					
			1900 EAST - WILMINGTON TO PARLEYS CANYON	5	5	0	450,000					
			700 W (1600 S TO 2100 S) ROADWAY	5	5	0	400,000					
			800 WEST 600 S to 800 S	5	5	0	250,000					
			500 EAST - 1700 SOUTH TO 2100 SOUTH	5	5	0	300,000					
			CITY WIDE STREET IMPROVEMENTS AND PRESERVATION 2019/2020	5	5	0	2,500,000					
			2000 E (PARLEYS CANYON BLVD TO CITY LIMIT) ROADWAY	5	5	0	200,000					
			300 W (900 S TO 2100 S) ROADWAY	5	5	0	150,000	2,000,000				
			900 EAST (HOLLYWOOD AVE TO 2700 S) ROADWAY	5	5	0		350,000				
			100 S (NORTH CAMPUS DRIVE TO 900 E) ROADWAY	5	5	0		500,000				
			1700 EAST (1700 S TO 2700 S) ROADWAY	5	5	0		550,000				
			CITY WIDE STREET IMPROVEMENTS AND PRESERVATION 2020/2021	5	5	0		2,500,000				
			300 WEST - 600 SOUTH to 2100 SOUTH	5	5	0			500,000			
			200 SOUTH - 400 WEST TO 900 EAST, PHASE 1	5	5	0			500,000			
			CITY WIDE STREET IMPROVEMENTS AND PRESERVATION 2021/2022	5	5	0			2,500,000			
			1100 EAST TO HIGHLAND - ROMONA AVE TO WARNOCK AVENUE	5	5	0				500,000		
			1100 EAST - 900 SOUTH TO RAMONA AVE	5	5	0				500,000		
			200 SOUTH - 400 WEST TO 900 EAST, PHASE 2	5	5	0				300,000		
			1300 EAST - 2100 SOUTH TO CITY BOUNDARY	5	5	0				500,000		
			CITY WIDE STREET IMPROVEMENTS AND PRESERVATION 2022/2023	5	5	0				2,500,000		
			VIRGINA STREET - SOUTH TEMPLE TO 11TH AVE	5	5	0					500,000	
			300 NORTH - 300 WEST TO 1000 WEST	5	5	0					500,000	
			CITY WIDE STREET IMPROVEMENTS AND PRESERVATION 2023/2024	5	5	0					2,500,000	
			900 SOUTH - 900 WEST TO 300 WEST AND WEST TEMPLE TO 900 EAST	5	5	0						1,000,000
			2100 SOUTH - 700 EAST TO 1700 EAST	5	5	0						500,000
			CITY WIDE STREET IMPROVEMENTS AND PRESERVATION 2023/2024	5	5	0						2,500,000
						1,835,286	6,455,000	7,955,000	5,200,000	6,000,000	5,200,000	9,500,000
			PIPE RENEWAL & REPLACEMENT PROGRAM									
10401	525002705	2015-0332	300 WEST - 500 NORTH TO 600 NORTH (WEST SIDE)		3	1,663						

SEWER UTILITY CIP BUDGET
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COST CENTER	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	CRITICALITY RATING	CONDITION RATING	PAST YEAR SPENT 2018-19 (Calc'd from P6)	BUDGET YEAR 2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
10401	525002708	2015-0333	WEST CAPITOL STREET - COLUMBUS STREET TO ZANE AVENUE TO WALL STREET		3	0						
10401	525002629	2015-0344	REDWOOD ROAD - PAXTON AVENUE TO CALIFORNIA AVENUE		3	96,755						
10401	525002780	2016-0840	4600 WEST DIVERSION I&I MITIGATION PROJECT		4	296,732						
	525002838		GLENDALE GOLF COURSE LATERAL			90,953						
10401		2015-0486	1% PER YEAR SEWER REHABILITATION/SYSTEM RENEWAL	5	5	0			2,650,000	3,000,000	3,000,000	20,000,000
	525002761	2015-0283	700 N I-15 BYPASS FOR INSPECTION OF EXISTING LINE	5	0	94,140	1,100,000					
10401	525002719	2015-0303	NORTH TEMPLE (100 N) - APPROX. 2050 WEST TO GLADIOLA STREET	5	5	150,000	2,100,000	200,000				
10401	2015-0722	2015-0722	TESORO SEWER TRUNK LINE REHABILITATION	5	4	0			250,000	6,000,000		
10401		2016-0897	WEST TEMPLE FROM TRUMAN AVE TO 1300 S CIPP	5	4	0				350,000	2,000,000	2,000,000
10401	2016-0902	2016-0902	800 S AND 1100 E LATERAL CONNECTIONS AND UPSTREAM INFILTRATION	3	4	0				20,000	150,000	
10401		2015-0727	300 W - 550 S TO 600 S	5	4	0					150,000	
10401	525002443	2016-0895	ELGIN AVE SEWER REPLACEMENT	3	3	0					400,000	
10401	2015-0318	2015-0318	700 SOUTH - 3750 WEST TO IRON ROSE PLACE (3830 W)	4	4	0					200,000	
	525002744	2016-0833	2300 EAST SEWER REHAB FROM EAST TO WEST SIDE OF FOOTHILL BLVD	5	5		60,000					
	525002774	2015-0728	ALLY BETWEEN LAKE ST AND 800 E	5	5		30,000					
	525002776	2015-0730	THIRD AVE FROM E ST TO F ST	5	5		30,000					
	525002836		OMNI AND STARCREST SEWER REHAB	5	5		50,000					
	525002858	2016-1050	CIPP SEWER ON 1675 E TOMAHAWK DR	5	5		100,000					
	525002772		WEST CAPITOL ST SANITARY SEWER MAIN FROM 490 N TO 520 N.	5	5		30,000					
10401	2016-0873	2016-0873	DOOLEY COURT	3	5	0	60,000					
	525002851	2017-2130	1200 WEST TRUNK LINE REHABILITATION PROJECT	5	5	400,106	1,000,000	4,000,000	4,000,000	4,000,000		
			BECK STREET TRUNK LINE REHABILITATION PROJECT	5	3	0					800,000	10,000,000
10401		2016-0908	3RD AVE D TO E STREET	3	5	0	140,000					
10401		2015-0731	MAIN ST - 320 N TO 340 N	4	5	0	110,000					
10401	525002355	2016-0861	6TH AVE FROM 588 E TO H ST	4	5	330,708	180,000					
10401	525002390	2016-0866	400 WEST FROM 100 NORTH TO 140 NORTH (WEST SIDE) CIPP INSTALLATION	3	4	0	40,000					
10401		2016-0989	2600 EAST AND BLAINE AVE REHABILITATION	3	5	0	150,000					
10401		2016-0991	CIPP SEWER ON FOOTHILL DR	3	5	0	110,000					
10401		2016-0992	WASATCH DR FROM 1300 SOUTH TO VILLAGE CIRCLE SEWER REHAB	3	5	0	260,000					
10401		2016-0993	FOOTHILL DR AND 1300 SOUTH SEWER REHAB	3	5	0	70,000					
10401		2016-0995	LOGAN WAY AND 1700 SOUTH SEWER REHAB	3	5	0	75,000					
10401		2016-0997	700 EAST FROM 2700 SOUTH TO CRYSTAL AVE SEWER REHAB	3	5	0	105,000					
10401		2016-0998	600 WEST 100 SOUTH SEWER REHAB	3	5	0	150,000					
10401		2016-1001	BROADMOOR ST FROM ELM AVE TO 2100 SOUTH SEWER REHAB	3	5	0	55,000					
10401		2016-1002	2300 EAST FROM STRINGHAM AVE TO BERNADINE DR SEWER REHAB	3	5	0	30,000					
10401		2016-1003	LYNWOOD DR SEWER REHAB	3	5	0	75,000					
10401		2016-1004	2300 EAST AND COUNTRY CLUB DRIVE SEWER REHAB	3	5	0	40,000					
10401		2016-1005	WILSHIRE CIRCLE SEWER REHAB	3	5	0	155,000					
10401		2016-1008	P STREET FROM 4TH AVE TO 3RD AVE SEWER REHAB	3	5	0	40,000					
10401		2016-1009	1ST AVE FROM T STREET TO U STREET SEWER REHAB	3	5	0	140,000					
10401		2016-1011	1200 EAST FROM FENWAY AVE TO 700 SOUTH SEWER REHAB	3	5	0	35,000					
10401		2016-1012	FULLER AVE FROM 1000 EAST TO 1100 EAST SEWER REHAB	3	5	0	35,000					
10401		2016-1013	500 SOUTH AND 1300 EAST SEWER REHAB	3	5	0	35,000					
10401		2016-1014	600 SOUTH 1300 EAST SEWER REHAB	3	5	0	45,000					
10401		2016-1016	1200 EAST AND 700 SOUTH SEWER REHAB	3	5	0	50,000					
10401		2016-1017	SUNNYSIDE AVE FROM CONNOR ST TO 2200 EAST SEWER REHAB	3	5	0	40,000					
10401		2016-1018	MICHIGAN AVE AND FOOTHILL BLVD SEWER REHAB	3	5	0	40,000					

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10401	525002829	2016-1019	FOOTHILL DRIVE AND 2100 EAST SEWER REHAB	3	5	0	90,000					
10401		2016-1020	LAIRD AVE SEWER REHAB	3	5	0	240,000					
10401	525002828	2016-1021	BROWNING AVE AND 1700 EAST	3	5	0	15,000					
10401	525002820	2016-1024	LOGAN AVE SEWER REHAB	3	5	0	100,000					
10401	525002800	2016-1026	1600 EAST FROM LOGAN AVE TO 1700 SOUTH SEWER REHAB	3	5	0	45,000					
10401		2016-1028	1900 EAST FROM 800 SOUTH AND 900 SOUTH SEWER REHAB	3	5	0	30,000					
10401		2016-1030	HARVARD AVE AND MCCLELLAND SEWER REHAB	3	5	0	90,000					
10401		2016-1031	BACKLOT BETWEEN PAXTON AVE AND FREMONT AVE SEWER REHAB	3	5	0	40,000					
10401		2016-1032	800 SOUTH FROM 700 EAST TO LAKE ST SEWER REHAB	3	5	0	85,000					
10401	525002804	2016-1035	2700 SOUTH AND IMPERIAL ST SEWER REHAB	3	5	0	100,000					
10401	525002809	2016-1036	JUDITH ST BETWEEN ZENNITH AVE AND HUDSON AVE SEWER REHAB	3	5	0	50,000					
10401	525002826	2016-1038	HOLLYWOOD AVE FROM 900 EAST TO LINCOLN ST SEWER REHAB	3	5	0	50,000					
10401	525002797	2016-1039	2100 SOUTH FROM 1900 EAST TO PRESTON ST SEWER REHAB	3	5	0	20,000					
10401		2016-1040	CIPP SEWER ON 800 EAST FROM SOUTH TEMPLE TO 100 SOUTH	3	5	0	10,000	100,000				
10401		2016-1041	CIPP SEWER ON 600 SOUTH FROM 500 EAST TO 600 EAST	3	5	0	5,000	50,000				
10401		2016-1042	CIPP SEWER ON 600 SOUTH 600 EAST	3	5	0	5,000	50,000				
10401		2016-1044	CIPP SEWER ON 300 WEST FROM ORCHARD PL TO 600 SOUTH	3	5	0	5,000	50,000				
10401		2016-1047	CIPP SEWER ON EMERSON AVE BETWEEN 2200 EAST AND 2300 EAST	3	5	0	6,500	65,000				
10401		2016-1048	CIPP SEWER ON ROOSEVELT AVE AND 2200 EAST	3	5	0	3,000	30,000				
10401		2016-1058	CIPP SEWER ON DARWIN ST FROM GIRARD AVE TO ZANE AVE	3	5	0	5,000	50,000				
10401		2016-1059	CIPP SEWER ON 1040 SOUTH BONNEVILLE DR	3	5	0	5,000	50,000				
10401		2016-1077	CIPP SEWER ON 1100 EAST BETWEEN 100 SOUTH AND 200 SOUTH	3	5	0	6,000	60,000				
10401		2016-1078	CIPP SEWER ON 200 SOUTH BETWEEN 900 EAST AND 1000 EAST	3	5	0	6,000	60,000				
10401		2016-1081	CIPP SEWER ON 1000 EAST BETWEEN 200 SOUTH AND 300 SOUTH	3	5	0	4,000	40,000				
10401		2016-1089	CIPP SEWER ALLEY WEST OF 600 E BETWEEN 800 SOUTH AND 900 SOUTH	3	5	0	20,000	200,000				
10401		2016-1090	CIPP SEWER ON GRACE CT AND WILLIAMS AVE	3	5	0	3,000	36,000				
10401		2016-1091	CIPP SEWER ON ALLEY EAST OF 300 EAST BETWEEN 800 SOUTH AND 900 SOUTH	3	5	0	3,000	36,000				
10401		2016-1093	CIPP SEWER ON 1700 EAST AND PARLEYS CANYON BLVD	3	5	0	3,000	36,000				
10401		2016-1094	CIPP SEWER ON FOURTH AVE FROM A STREET TO B STREET	3	5	0	3,000	36,000				
10401		2016-1096	CIPP SEWER ON THIRD AVE FROM E STREET TO F STREET	3	5	0	8,000	85,000				
10401		2016-1097	CIPP SEWER ON J STREET BETWEEN THIRD AVE AND FOURTH AVE	3	5	0	17,000	170,000				
10401		2016-1098	CIPP SEWER ON SECOND AVE BETWEEN F STREET AND G STREET	3	5	0	15,000	150,000				
10401		2016-1099	D STREET FROM FIRST AVE TO SECOND AVE SEWER REHAB	3	5	0	60,000					
10401		2016-1102	CIPP SEWER ON K STREET FROM SOUTH TEMPLE TO FIRST AVE	3	5	0	7,000	70,000				
10401		2016-1100	CIPP SEWER ON E STREET BETWEEN FIRST AVE AND SECOND AVE	3	5	0	4,000	40,000				
10401		2016-1103	CIPP SEWER ON 500 EAST BETWEEN SOUTH TEMPLE AND 100 SOUTH	3	5	0	10,000	105,000				
10401		2016-1104	CIPP SEWER ON SLADE PL AND 500 EAST	3	5	0	3,000	32,000				
10401		2016-1105	CIPP SEWER ON 300 SOUTH AND 300 EAST	3	5	0	65,000	642,000				
10401		2016-1110	CIPP ON A STREET BETWEEN SOUTH TEMPLE AND FIRST AVE	3	5	0	6,000	65,000				
10401		2016-1112	CIPP SEWER ON 200 EAST BETWEEN 200 SOUTH AND 300 SOUTH	3	5	0	6,000	60,000				
10401		2016-1113	CIPP SEWER ON 200 EAST BETWEEN 300 SOUTH AND 400 SOUTH	3	5	0	20,000	200,000				
10401		2016-1114	CIPP SEWER ON 200 WEST FROM 200 NORTH TO 300 NORTH	3	5	0	5,000	15,000				
10401		2016-1116	CIPP SEWER ON WEST TEMPLE BETWEEN 200 SOUTH AND 300 SOUTH	3	5	0	6,000	60,000				
10401		2016-1117	CIPP SEWER ON 200 SOUTH BETWEEN REGENT ST AND STATE ST	3	5	0	9,000	90,000				
10401		2016-1118	CIPP SEWER ON 200 SOUTH BETWEEN WEST TEMPLE AND MAIN ST	3	5	0	4,000	40,000				
10401		2016-1119	CIPP SEWER ON 400 SOUTH BETWEEN WEST TEMPLE AND MAIN ST	3	5	0	7,000	70,000				
10401		2016-1120	CIPP SEWER ON 400 SOUTH BETWEEN MAIN ST AND CACTUS ST	3	5	0	5,000	50,000				

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10401		2016-1121	CIPP SEWER ON MENLO AVE AND 800 EAST	3	5	0	6,000	60,000				17,000
10401		2016-1087	1700 SOUTH AND 1700 EAST SEWER REHAB	3	4	0			75,000			
10401		2016-1088	CIPP SEWER ON FAYETTE AVE AND WEST TEMPLE	3	4	0						17,000
10401		2016-1010	CIPP SEWER ON 1000 EAST FROM SOUTH TEMPLE TO 100 SOUTH	3	4	0						19,000
10401		2016-1101	CIPP SEWER ON B STREET BETWEEN SOUTH TEMPLE AND FIRST AVE	3	4	0						12,000
10401		2016-1109	CIPP SEWER ON ELY PL AND 700 EAST	3	4	0						20,000
10401		2016-1111	CIPP SEWER ON 200 EAST FROM 250 SOUTH TO 300 SOUTH	3	4	0						16,000
10401		2016-1115	CIPP SEWER ON 200 NORTH BETWEEN WEST TEMPLE AND ALMOND ST	3	4	0						11,000
10401		2016-1122	CIPP SEWER ON EDGEHILL ROAD AND LITTLE VALLEY ROAD	3	4	0						16,000
10401		2016-1123	CIPP SEWER ON 700 EAST EIGHTEENTH AVE	3	4	0						17,000
10401		2016-1124	CIPP SEWER ON NORTHMONT WAY AND EIGHTEENTH AVE	3	4	0						23,000
10401		2016-1126	CIPP SEWER ON TERRACE HILLS DR BETWEEN NORTHCREST DR AND NORTH BONNEVILLE	3	4	0						18,000
10401		2016-1129	CIPP SEWER ON H STREET BETWEEN ELEVENTH AVE AND TWELFTH AVE	3	4	0						13,000
10401		2016-1131	CIPP SEWER ON H STREET BETWEEN TENTH AVE AND ELEVENTH AVE	3	4	0						25,000
10401		2016-1132	CIPP SEWER ON NINTH AVE BETWEEN K STREET AND L STREET	3	4	0						21,000
10401		2016-1140	CIPP SEWER ON DORCHESTER DR FROM BRAEWICK RD TO SANDRUN RD	3	4	0						13,000
10401		2016-1142	CIPP SEWER ON B STREET FROM SIXTH AVE TO SEVENTH AVE	3	4	0						26,000
10401		2016-1144	CIPP SEWER ON 600 WEST FROM 400 NORTH TO 350 NORTH	3	4	0						21,000
10401		2016-1145	CIPP SEWER ON DONNER WAY FROM THACKERAY PL TO SHAKESPEARE PL	3	4	0						20,000
10401		2016-1152	CIPP SEWER ON KENSINGTON AVE AND BEACON DR	3	4	0						12,000
10401		2016-1153	CIPP SEWER ON CANTERBURY DR FROM LANCASTER DR TO WILTON WAY	3	4	0						25,000
10401		2016-1154	CIPP SEWER CANTERBURY DR AND LANCASTER DR	3	4	0						19,000
10401		2016-1155	CIPP SEWER 1515 SOUTH DEVONSHIRE DR TO LANCASTER DR	3	4	0						14,000
10401		2016-1156	CIPP SEWER ON UTE DR FROM INDIAN HILL CIRCLE TO EAGLE WAY	3	4	0						18,000
10401		2016-1157	CIPP SEWER ON COMANCHE DR AND EAGLE WAY	3	4	0						5,000
10401		2016-1158	CIPP SEWER ON WASATCH DR BETWEEN 1700 SOUTH AND SKYLINE DR	3	4	0						20,000
10401		2016-1172	CIPP SEWER FROM 1911 SOUTH FOOTHILL TO 1975 SOUTH FOOTHILL	3	4	0						19,000
10401		2016-1197	CIPP SEWER ON LOGAN WAY AT 1700 SOUTH	3	4	0						10,000
10401		2016-1198	CIPP SEWER ON BLAINE AVE AND TEXAS ST	3	4	0						15,000
10401		2016-1207	CIPP SEWER ON INDUSTRIAL AVE AND 1700 SOUTH	3	4	0						7,000
10401		2016-1209	CIPP SEWER ON 2300 EAST BETWEEN CLUBHOUSE DR AND MAYWOOD DR	3	4	0						18,000
10401		2016-1212	CIPP SEWER FROM 2526 EAST COMMONWEALTH TO WYOMING ST	3	4	0						20,000
10401		2016-1213	CIPP SEWER ON 2000 EAST BETWEEN WILSON AVE AND DOWNINGTOWN AVE	3	4	0						18,000
10401		2016-1214	CIPP SEWER FROM 1838 EAST DOWNINGTOWN AVE TO 1800 EAST	3	4	0						23,000
10401		2016-1215	CIPP SEWER ON 2100 EAST FROM WILSON AVE TO DOWNINGTOWN AVE	3	4	0						14,000
10401		2016-1216	CIPP SEWER ON 2000 EAST FROM DOWNINGTOWN AVE TO GARFIELD AVE	3	4	0						18,000
10401		2016-1218	CIPP SEWER ON 1700 SOUTH FROM 1860 EAST TO 1800 EAST	3	4	0						19,000
10401		2016-1219	CIPP SEWER ON 1700 EAST AND PARLEYS CANYON BL	3	4	0						4,000
10401		2016-1229	CIPP SEWER ON GLENMARE ST BETWEEN STRATFORD AVE AND 2700 SOUTH	3	4	0						19,000
10401		2016-1239	CIPP SEWER ON BEVERLY ST BETWEEN ATKIN AVE AND CLAYBOURNE AVE	3	4	0						17,000
10401		2016-1241	CIPP SEWER ON HUDSON AVE BETWEEN HIGHLAND DRIVE AND 1400 EAST	3	4	0						23,000
10401		2016-1242	CIPP SEWER ON SYLVAN AVE BETWEEN 1900 EAST AND 2000 EAST	3	4	0						22,000
10401		2016-1245	CIPP SEWER ON THIRD AVE AT CANYON ROAD	3	4	0						13,000
10401		2016-1246	CIPP SEWER ON STATE STREET BETWEEN 126 N AND 200 NORTH	3	4	0						19,000
10401		2016-1248	CIPP SEWER ON C STREET BETWEEN FIFTH AVE AND SIXTH AVE	3	4	0						24,000
10401		2016-1253	CIPP SEWER ON 300 NORTH BETWEEN 550 WEST AND 600 WEST	3	4	0						20,000
10401		2016-1256	CIPP SEWER ON UNIVERSITY BLVD (500 S) FROM 1500 EAST TO GUARDSMAN WAY	3	4	0						17,000

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10401		2015-0309	500 SOUTH - 3415 WEST TO 3600 WEST	3	3	0						224,000
10401		2016-0964	CIPP SEWER PIPE 1480 EAST TOMAHAWK DRIVE	3	3	0						12,000
10401		2016-0965	CIPP SEWER PIPE FROM 1536 E TOMAHAWK DR TO CHANDLER DR	3	3	0						20,000
10401		2016-0821	ELGIN AVE 1000 E - 950 E	2	4	0						200,000
10401		2017-1302	LEARNED AVE 1034 TO 1000 WEST	2	4	0						10,000
10401		2017-1307	2600 EAST 1750 TO 1889 SOUTH	2	4	0						50,000
10401		2016-0967	8-IN CIPP SEWER LINE FROM CAMBRIDGE WAY TO 1330 EAST PERRYS HOLLOW	3	3	0						9,000
10401		2016-0974	CIPP SEWER ON 1500 WEST FROM TALISMAN DR TO 895 NORTH	3	3	0						14,000
10401		2016-0977	CIPP SEWER BONNEVILLE DR	3	3	0						19,000
10401		2016-0980	CIPP SEWER ON OQUIRRH DRIVE	3	3	0						21,000
10401		2016-0982	CIPP SEWER AT ST MARY'S WAY AND OQUIRRH DRIVE	3	3	0						24,000
10401		2016-1006	CIPP SEWER ON 4TH AVE FROM VIRGINIA ST TO U ST	3	3	0						22,000
10401		2016-1007	CIPP SEWER ON FORT DOUGLAS CIRCLE	3	3	0						15,000
10401		2016-1015	CIPP SEWER ON BERKELEY ST AND WILMINGTON AVE	3	3	0						19,000
10401		2016-1049	CIPP SEWER ON TOMAHAWK DR	3	3	0						10,000
10401		2016-1051	CIPP SEWER ON 1675 EAST TOMAHAWK DR	3	3	0						13,000
10401		2016-1052	CIPP SEWER ON VIRGINIA ST FROM CHANDLER DR TO KRISTIANNA CIR	3	3	0						12,000
10401		2016-1053	CIPP SEWER ON KRISTIANNA CIR AND VIRGINIA ST	3	3	0						18,000
10401		2016-1054	CIPP SEWER ON ROUNDTOFT DR TO EAST CAPITOL BLVD	3	3	0						10,000
10401		2016-1062	CIPP SEWER ON SECOND AVE FROM L STREET TO M STREET	3	3	0						21,000
10401		2016-1092	CIPP SEWER ON 2100 SOUTH 1410 EAST	3	3	0						29,000
10401		2016-1127	CIPP SEWER ON 550 EAST NORTHHILLS DR	3	3	0						15,000
10401		2017-1305	1600 SOUTH INDUSTRIAL ROAD	1	5	0						25,000
10401		2016-0969	CIPP SEWER LINE ON 300 WEST FROM 400 NORTH TO BISHOP PL	3	2	0						1,000
10401		2016-1066	CIPP SEWER ON M STREET BETWEEN FIRST AND SECOND AVE	3	2	0						15,000
10401	525002849		1700 NORTH UNDER CITY DRAIN - BYPASS AND REHABILIATION	5	5	40,000	400,000					
			POINT REPAIR PROGRAM (VARIOUS LOCATIONS)									
10401	525002690	2015-0477	POINT REPAIRS IN SUPPORT OF CIPP PROGRAM (VARIOUS LOCATIONS)	3	5	0		350,000	350,000	350,000	350,000	1,400,000
			TOTAL COLLECTION LINES			1,501,058	8,475,500	7,503,000	7,325,000	13,720,000	7,050,000	37,188,000
			MANHOLE REHAB PROGRAM (VARIOUS LOCATIONS)									
10401		2015-0478	MANHOLE REHAB PROGRAM (VARIOUS LOCATIONS)	5	5	0	450,000	350,000	350,000	350,000	350,000	2,100,000
	525002832		500 SOUTH SURPLUS SIPHON VAULT REPLACEMENT (MH 05225)		5	90,779	400,000					
						90,779	850,000	350,000	350,000	350,000	350,000	2,100,000
			OTHER PROJECTS									
10401	525002839	2015-0376	ON-CALL TASK ORDER GENERAL CONSTRUCTION SERVICES (VARIOUS LOCATIONS)		5	300,000						
10401	52520035	2015-0485	CONTRIBUTIONS BY DEVELOPERS	5	5	0	500,000	500,000	500,000	500,000	500,000	2,000,000
	52510023	2016-1267	COLLECTION SYSTEM PROJECTS GENERAL SUPPORT - TASK 2	5	0	1,500,000	2,000,000	2,000,000	1,500,000	1,500,000	750,000	750,000
	525002786		PROGRAM MANAGEMENT SERVICES - TASK 1			0	350,000	350,000	350,000	350,000	350,000	350,000
		2016-0839	TDS REDUCTION PROGRAM	1	0	0						500,000
						1,800,000	2,850,000	2,850,000	2,350,000	2,350,000	1,600,000	3,600,000
			MASTER PLAN IMPLEMENTATION PROGRAM									

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10401	525002524	2015-0279	500 SOUTH INTERCEPTOR - ORANGE TO 1000 WEST		5	1,720,290						
10401	525002698	2015-0286	MP12A - 700 SOUTH CAPACITY UPGRADES – 4650 WEST TO 3400 WEST	5	5	14,004,129	250,000					
10401	52490785	2016-1260	500 SOUTH DIVERSION, PHASE II (PUMP STATION)	5	5	11,976,147	2,000,000					
10401	525002850	2016-0950	MP13 - BECK STREET TRUNK REPLACEMENT FROM 500 SOUTH AND STATE STREET TO 700 S(	5	5	522,328	1,000,000	6,000,000	11,000,000			
10401	525002376		1800 NORTH BECK STREET TO THE PRETREATMENT PLANT	5	5	2,608,982	3,000,000	12,000,000	6,000,000			
10401	525002423	2015-0320	MP8A - 1500 SOUTH - 2700 WEST TO REDWOOD ROAD	4	5	840,877	500,000					
10401	525002631	2015-0280	ORANGE STREET - PHASE IV - INDIANA TO 1500 SOUTH	5	4	0						6,131,000
10401	52490787	2015-0269	MP12D - 700 SOUTH LIFT STATION (SS 10)	5	4	493,341	7,000,000					
10401	2016-0929	2016-0929	MP16 - 600 WEST AND 700 SOUTH TO 500 WEST AND 800 SOUTH	5	4	0					1,400,000	
10401	2016-0930	2016-0930	MP17A - 900 SOUTH FROM RICHARD STREET TO MAIN STREET	5	4	0	250,000	1,000,000				
10401	2016-0931	2016-0931	MP17B - MAIN STREET FROM 800 SOUTH TO 900 SOUTH	5	4	0						809,100
10401	2016-0932	2016-0932	MP18 - 300 WEST FROM FAYETTE AVE TO 900 SOUTH	5	4	0						800,000
10401	2016-0940	2016-0940	MP19 - FOLSOM AVENUE FROM 500 WEST TO 1000 WEST	5	4	0						13,500,000
10401	2016-0941	2016-0941	MP20 - 700 WEST FROM 900 SOUTH TO 600 SOUTH	5	4	0						5,500,000
10401	2016-0942	2016-0942	MP21 - 100 SOUTH AND 300 WEST DIVERSION	5	4	0						300,000
10401		2015-0284	500 S SEWER REPLACEMENT FROM 3200 W TO ORANGE STREET	4	4	0						17,150,000
10401	2015-0322	2015-0322	MP28 - NORTH TEMPLE - AIRPORT TO ORANGE STREET	4	4	0					750,000	15,500,000
10401	2016-0949	2016-0949	MP26 - SOUTH TEMPLE AND 400 WEST DIVERSION	4	4	0						250,000
10401	525002577	2016-0849	MP15 - 700 SOUTH INTERCEPTOR CAPACITY UPGRADE	4	4	508,500	3,000,000	500,000				
10401	525002584	2016-0905	MP7 - 100 SOUTH 1200 EAST DIVERSION FOR CAPACITY	4	4	0	400,000					300,000
10401	2016-0943	2016-0943	MP22 - PIONEER ROAD FROM CALIFORNIA AVENUE TO 1500 SOUTH	4	4	0				1,500,000	6,500,000	1,000,000
10401	2016-0947	2016-0947	MP24 - 400 SOUTH FROM 300 WEST TO 600 WEST	4	4	0						3,000,000
10401	2016-0953	2016-0953	MP31 - 600 SOUTH FROM 800 WEST TO 900 WEST	4	3	0						2,000,000
10401	525002507	2015-0321	MP8B - 3230 WEST - 1820 SOUTH TO 1670 SOUTH	3	4	397,056				1,000,000	5,000,000	
10401	2016-0952	2016-0952	MP30 - 200 EAST FROM 300 SOUTH TO 500 SOUTH	4	3	0						2,000,000
10401		2016-0946	MP23 - PARALLEL 1000 WEST 48-INCH TRUNK	4	3	0						20,000,000
10401	2016-1195	2016-1195	MP29 - BECK STREET TRUCK REPLACEMENT FROM 200 SOUTH AND 300 WEST TO STATE STR	4	3	0						16,000,000
10401		2016-0841	500 S. PUMP AND THIRD FORCE MAIN INSTALLATION	5	1	0						10,000,000
10401	2016-0954	2016-0954	MP32 - 700 WEST FROM 700 SOUTH TO 500 SOUTH (EAST SIDE OF I-15)	3	3	0						3,000,000
10401	2016-0955	2016-0955	MP33 - 1300 EAST FROM 400 SOUTH TO 500 SOUTH	3	3	0	450,000					
10401		2015-0660	SATELLITE TREATMENT PLANT	5	0	0						405,500,000
10401			700 S. PUMP AND THIRD FORCE MAIN INSTALLATION			0						10,000,000
						33,071,650	17,850,000	19,500,000	17,000,000	2,500,000	13,650,000	532,740,100
			Total Collection System			39,132,179	36,630,500	38,558,000	32,575,000	25,370,000	28,050,000	587,528,100
	2730.20		**LANDSCAPING**									3,372,750
10401	525002689		NORTHWEST OIL DRAIN			0	150,000					
						0	150,000	0	0	0	0	3,372,750
			TOTAL CAPITAL IMPROVEMENTS			60,892,051	98,370,500	125,728,000	210,160,000	162,630,000	94,660,000	618,230,850

SEWER UTILITY CAPITAL PURCHASES BUDGET
Five Year Projected Budget FY2020-2024

COST CENTER	OBJECT CODE	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	Comments	CRITICALITY RATING	CONDITION RATING	PAST YEAR 2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
	2710.10			LAND										
5210401			2015-0481	500 SOUTH LAND PURCHASE		5	5		4,100,000					
5210401				LAND EASEMENT FOR 700 SOUTH SEWER LINE		4	4							
5210401			2016-0887	SHURTLEFF AND ANDREWS SECONDARY ACCESS		4	4		500,000					
5210401				LAND EASEMENT FOR 500 SOUTH MP PROJECT TO ORANGE STREET		4	4		1,000,000					
5210401			2016-0870	EASEMENT NORTH OF OQUIRRH DR		4	4							
								0	5,600,000	0	0	0	0	0
	2750.10			AUTOMOBILES & TRUCKS										
5212201	2750.10			Electric Club Car Qty. 4										
5210801	2750.10			Transit Van w/Upfit										
5210101	2750.10			3/4 Ton Truck w/Service Body 4X4										
5210601	2750.10		3387	Int. 1 ton Cab-n-Chassis w/ Dump Bed				47,157						
5210101	2750.10		36910	GMC 3/4 ton Ext Cab Pick-up Truck				56,165						
5211201	2750.10		3418	Chev 3/4 ton Ext Cab Pick-up Truck				34,390						
5211201	2750.10		3425	Chev 1 ton Cab-n-Chassis Util. Bed & Crane				31,640						
5211201	2750.10		3488	GMC 1/2 ton Cab-n-Chassis w/ Utility Body				30,031						
5212201	2750.10		49/63/58/62	Golf Cart Enclosed Cab Dump Bed Qty 4				56,000						
5210401	2750.10			CHEV OR SIMILAR MID-SIZED 4X4 PICK UP W/BED COVER	Jason				30,000					
5212201	2750.10		3428	Replace Volvo Wg64, Mack Granite 64 br	Jamey				190,000					
5212201	2750.10		34030	Replace Stering LT9500, Mack Granite 64 br	Jamey				190,000					
5212201	2750.10		34310	Replace International 2674 6x4, Mack Granite 64 br	Jamey				190,000					
5212201	2750.10		34020	Replace International 7400 4x2, Vactor	Jamey				500,000					
5212301	2750.10		3485	Replace Ford F-350, Chevrolet Silverado 3500HD 4x4	Jamey				40,000					
5212301	2750.10		3458	GMC Sierra 3500HD Flatbed Dump	Jamey				49,000					
5210601	2750.10		33080	Mack GU713	Randy				460,000					
5210601	2750.10		33880	GMC Sierra 2500	Randy				31,000					
5210101	2750.10		33890	GMC Sierra 2500 W/Service Body	Randy				37,500					
5212301				VARIOUS										
								255,383	1,717,500	0	0	0	0	0
	2750.30			FIELD MAINTENANCE EQUIP.										
5210601				BACKHOE EXCHANGE				8,000	8,000	8,000	8,000	8,000	8,000	
5210801				REHAB OLD CCTV VAN										
5210601				VARIOUS					400,000	400,000	400,000	400,000	400,000	
5210601				PUMP TRUCK - LARGE DIAMETER PIPE CLEANING MACHINE										
5210601				Cat Backhoe Buyback Program				9,000						
5211201				40 Ton Rough Terrain Crane for Water Rec				462,403						
5210601				BOBCAT SKID STEER										
								479,403	408,000	408,000	408,000	408,000	408,000	0
	2760.10			PUMP PLANT EQUIPMENT										

SEWER UTILITY CAPITAL PURCHASES BUDGET
Five Year Projected Budget FY2020-2024

COST CENTER	OBJECT CODE	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	Comments	CRITICALITY RATING	CONDITION RATING	PAST YEAR 2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
5211201	2760.10			SLC WRF Pump Plant Exterior Lighting Upgrades	Michael				35,000					
5211201	2760.10			SLC WRF Influent Pump Discharge Ball Valves	Michael				200,000					
									235,000	0	0	0	0	0
	2760.20			TREATMENT PLANT EQUIPMENT										
5212201	2760.20			COMPRESSORS AND BLOWERS										
5212201	2760.20			PUMPS										
5211201	2760.20			AERATION BASIN DRAINAGE PUMP REPLACEMENTS (10)				100,000						
5211201	2760.20			REPLACEMENT #2 WATER PUMP				100,000						
5211201	2760.20			PUMP PLANT GRIT PUMP REPLACEMENT (2)				6,778						
5211201	2760.20			SUPPLIED AIR SYSTEM REPLACEMENT CL2 BLDG				20,000						
5211201	2760.20			DIGESTER ROOF WALK WAY IMPROVEMENTS				10,000						
5211201	2760.20			HVAC REPLACEMENTS (3)				120,000						
5211101	2760.20			XPE205 METTLER TOLEDO ANALYTICAL BALANCE										
5211101	2760.20			LACHAT/HATCH 2-CHANNEL FIA + IC CONFIGURATION										
5211201	2760.20			Primary Trickling Filter Overflow Gate	Michael				20,000					
5211201	2760.20			SLC WRF HVAC Improvements	Michael									
5211201	2760.20			East Maitenance	Michael				18,000					
5211201	2760.20			Pre Treatment	Michael				5,500					
5211201	2760.20			Switch Gear #3	Michael				5,500					
5211201	2760.20			Chillers (2)	Michael				80,000					
5211201	2760.20			Administration	Michael				40,000					
5211201	2760.20			Digester MCC Room	Michael				5,000					
5211201	2760.20			South Ras	Michael				5,500					
5211201	2760.20			North Ras	Michael				5,500					
5211201	2760.20			TWAS Electrical Room	Michael				5,500					
5211201	2760.20			All Swamp Coolers (6)	Michael				27,000					
5211201	2760.20			SLC WRF Grease Pump	Michael				20,000					
5211201	2760.20			SLC WRF Snail Pump	Michael				15,000					
5211201	2760.20			SLC WRF Trickling Filter Motor VFD Replacement (6)	Michael				6,000					
5211201	2760.20			SLC WRF Bio Gas Heat Exhanger Upgrade	Michael				75,000					
5211201	2760.20			SLCWRF Co-Gen Controls	Michael				50,000					
5211201	2760.20			SLCWRF #2 Water Filters (2)	Michael				90,000					
5211201	2760.20			SLCWRF Co-Gen Oil Filter Replacement (2)	Michael				70,000					
5212201				VARIOUS						225,000	225,000	225,000	225,000	
								356,778	543,500	225,000	225,000	225,000	225,000	450,000
	2760.30			TELEMETERING EQUIPMENT										
5211201	52540048			TELEMETERING UPGRADE - REPLACE										
5210101				SCADA SYSTEM REPLACE				10,000	10,000	10,000	10,000	10,000	10,000	
								10,000	10,000	10,000	10,000	10,000	10,000	20,000
	2760.50			OFFICE FURNITURE & EQUIPMENT										

SEWER UTILITY CAPITAL PURCHASES BUDGET
Five Year Projected Budget FY2020-2024

COST CENTER	OBJECT CODE	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	Comments	CRITICALITY RATING	CONDITION RATING	PAST YEAR 2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
5211301				Server replacement "SLCIWRDB"				9,000						
5211701				Core Switch										
5212401				FULL FUNCTION PRINTER REPLACEMENT PRE-TREATMENT SMALL				5,765						
5212201				VARIOUS				20,000	20,000	20,000	20,000	20,000	20,000	
								34,765	20,000	20,000	20,000	20,000	20,000	20,000
	2760.90			OTHER NON-MOTIVE EQUIPMENT										
5210601				TOW ALONG CEMENT MIXER										
5212201				STATIONARY SAMPLER W/ENCLOSURE										
5212401				VARIOUS NON-MOTIVE EQUIPMENT					160,000	160,000	160,000	160,000	160,000	
5212201				UPGRADE LAB ANALYTICLA EQUIPMENT										
5212201				Washer Compactor for Primary Sludge Screens										
5210601				Vanguard System										
5210601				HANDHELD RADIO REPLACEMENT				57,902						
5210801				REPLACEMENT PUSH CAMERA				11,000						
5210801				NEW LATERAL LAUNCH ADD ON SYSTEM				67,338						
5211101				LABORATORY SPECTROPHOTOMETER REPLACEMENT				5,000						
5211101				LABORATORY DIGITAL BALANCE REPLACEMENT				5,000						
5211401				SURVEY GRADE GPS UNIT				20,000						
								166,240	160,000	160,000	160,000	160,000	160,000	0
				TOTAL CAPITAL OUTLAY				**1,302,569**	**8,694,000**	**823,000**	**823,000**	**823,000**	**823,000**	**490,000**

Stormwater Utility- Budget Summary and Cash Flow

STORMWATER UTILITY
ENTERPRISE FUND
BUDGET SUMMARY
FY 2020-2022

SOURCES		ACTUAL 2017-18		AMENDED BUDGET 2018-19		PROJECTED ACTUAL 2018-19		PROPOSED BUDGET 2019-20 (Rate increase 10%)		FORECAST BUDGET 2020-21 (Rate increase 10%)		FORECAST BUDGET 2021-22 (Rate increase 10%)
REVENUES												
METERED SALES	$	8,508,507	$	8,855,000	$	8,855,000	$	**9,740,500**	$	10,714,550	$	11,678,860
INTEREST INCOME		124,773		33,000		33,000		**20,820**		174,816		38,338
OTHER REVENUES		1,027,830		1,000		1,000		**1,000**		1,000		1,000
TOTAL REVENUES	$	9,661,110	$	8,889,000	$	8,889,000	$	**9,762,320**	$	10,890,366	$	11,718,198
OTHER SOURCES												
GRANTS & OTHER RELATED REVENUES		354,475		650,000		650,000		**516,000**		516,000		516,000
COUNTY FLOOD CONTROL		-		-		-		**-**		-		-
IMPACT FEES		366,456		200,000		200,000		**200,000**		200,000		200,000
SHORT-TERM FINANCING		-		1,355,000		-		**-**		-		-
BOND PROCEEDS		-		-		-		**14,581,000**		-		6,159,200
TOTAL OTHER SOURCES	$	720,931	$	2,205,000	$	850,000	$	**15,297,000**	$	716,000	$	6,875,200
TOTAL SOURCES	$	10,382,041	$	11,094,000	$	9,739,000	$	**25,059,320**	$	11,606,366	$	18,593,398
EXPENSES & OTHER USES												
EXPENDITURES												
PERSONNEL SERVICES	$	2,390,383	$	2,872,608	$	2,872,608		**3,187,954**	$	3,315,474	$	3,448,092
OPERATING & MAINTENANCE		152,863		186,450		186,450		**200,950**		204,769		208,864
TRAVEL & TRAINING		7,009		12,750		12,750		**16,265**		16,590		16,922
UTILITIES		188,079		244,045		244,045		**244,045**		248,926		253,903
TECHNICAL SERVICES		632,693		2,141,221		2,141,221		**1,304,999**		1,230,399		1,241,007
PUBLIC SERVICES / STREET SWEEPING		819,605		819,605		819,605		**819,605**		835,997		852,717
DATA PROCESSING		317,811		239,700		239,700		**304,000**		310,080		316,282
FLEET MAINTENANCE		223,731		214,000		214,000		**214,000**		218,280		222,645
ADMINISTRATIVE SERVICE FEE		101,615		130,000		130,000		**120,000**		122,400		124,848
PAYMENT IN LIEU OF TAXES		109,785		125,942		125,942		**100,434**		102,443		104,492
BILLING COST		423,849		554,117		554,117		**545,417**		556,325		567,452
RISK MANAGEMENT		57,985		86,983		86,983		**84,842**		86,539		88,269
TRANSFERS TO GENERAL FUND		-		4,000		4,000		**4,000**		4,080		4,162
OTHER CHARGES AND SERVICES		98,689		27,899		27,899		**25,857**		27,101		27,641
TOTAL EXPENDITURES	$	5,524,097	$	7,659,320	$	7,659,320	$	**7,172,368**	$	7,279,403	$	7,477,296
OTHER USES												
CAPITAL OUTLAY		197,620		515,568		515,568		**728,149**		620,000		620,000
CAPITAL IMPROVEMENT BUDGET		2,392,384		6,522,769		3,783,053		**12,744,000**		7,630,000		4,371,000
COST OF DEBT ISSUANCE		-		10,000		-		**81,000**		-		34,200
DEBT SERVICES		1,017,494		1,014,000		1,014,000		**1,225,000**		1,649,000		1,652,000
TOTAL OTHER USES	$	3,607,498	$	8,062,337	$	5,312,621	$	**14,778,149**	$	9,899,000	$	6,677,200
TOTAL USES	$	9,131,595	$	15,721,657	$	12,971,941	$	**21,950,517**	$	17,178,403	$	14,154,496
EXCESS REVENUE AND OTHER SOURCES OVER (UNDER) USES	$	1,250,446	$	(4,627,657)	$	(3,232,941)	$	**3,108,803**	$	(5,572,037)	$	4,438,902
OPERATING CASH BALANCES												
BEGINNING JULY 1	$	5,316,077	$	6,566,523	$	6,566,523	$	**3,333,582**	$	6,442,385	$	870,348
ENDING JUNE 30	$	6,566,523	$	1,938,866	$	3,333,582	$	**6,442,385**	$	870,348	$	5,309,250
Cash Reserve Ratio		119%		25%		44%		90%		12%		71%

Cash reserve goal above 10%

STORMWATER UTILITY
CASH FLOW
FY 2020 BUDGET
AND FY 2021-2024 FORECAST

10%,10%,9%,6%,5% Rates
$20.6M in Bonds,$14.5M FY20 and $6.2M FY22
New Debt Pmts $3.1M thru FY24
100% Capital Budget FY 20 thru 24

	ACTUAL YEAR 2017-2018	PROJECTED YEAR 2018-2019	BUDGET YEAR 2019-2020	BUDGET YEAR 2020-2021	BUDGET YEAR 2021-2022	BUDGET YEAR 2022-2023	BUDGET YEAR 2023-2024
STORMWATER CHARGES	8,508,507	8,855,000	9,740,500	10,714,550	11,678,860	12,379,591	12,998,571
OTHER INCOME	1,027,830	1,000	1,000	1,000	1,000	1,000	1,000
INTEREST INCOME	124,773	33,000	20,820	174,816	38,338	106,254	51,104
OPERATING INCOME	9,661,110	8,889,000	9,762,320	10,890,366	11,718,198	12,486,845	13,050,675
OPERATING EXPENDITURES	(5,524,097)	(7,659,320)	(7,172,368)	(7,279,403)	(7,477,296)	(7,681,804)	(7,343,160)
NET INCOME EXCLUDING DEP.	4,137,013	1,229,680	2,589,952	3,610,963	4,240,902	4,805,041	5,707,515
IMPACT FEES	366,456	200,000	200,000	200,000	200,000	200,000	200,000
SHORT-TERM FINANCING							
NET BOND PROCEEDS			14,500,000		6,125,000		
COST OF ISSUANCE (PROCEEDS)		0	81,000	0	34,200	0	0
COST OF ISSUANCE (EXP.)		0	(81,000)	0	(34,200)	0	0
OTHER CONTRIBUTIONS	354,475	650,000	516,000	516,000	516,000	516,000	516,000
CAPITAL OUTLAY	(197,620)	(515,568)	(728,149)	(620,000)	(620,000)	(620,000)	(620,000)
SHORT-TERM DEBT							
DEBT SERVICE (NEW)		0	(213,000)	(638,000)	(638,000)	(638,000)	(925,000)
DEBT SERVICE	(1,017,494)	(1,014,000)	(1,012,000)	(1,011,000)	(1,014,000)	(1,009,000)	(1,018,000)
OTHER INCOME & EXPENSE	(494,183)	(679,568)	13,262,851	(1,553,000)	4,569,000	(1,551,000)	(1,847,000)
GENERATED FOR CAPITAL	3,642,830	550,112	15,852,803	2,057,963	8,809,902	3,254,041	3,860,515
CAPITAL IMPROVEMENTS	(2,392,384)	(3,783,053)	(12,744,000)	(7,630,000)	(4,371,000)	(7,023,000)	(4,300,000)
BEGINING CASH BALANCE	5,316,077	6,566,523	3,333,582	6,442,385	870,348	5,309,250	1,540,291
CASH INCREASE/(DECREASE)	1,250,446	(3,232,941)	3,108,803	(5,572,037)	4,438,902	(3,768,959)	(439,485)
ENDING BALANCES	6,566,523	3,333,582	6,442,385	870,348	5,309,250	1,540,291	1,100,806
AMOUNT RESTRICTED							
DEBT SERVICE COVERAGE	**4.07**	**1.21**	**2.11**	**2.19**	**2.57**	**2.92**	**2.94**
RATE CHANGE	0%	10%	10%	10%	9%	6%	5%
Cash Reserve Ratio	**119%**	**44%**	**90%**	**12%**	**71%**	**20%**	**0**
Minimum Reserve	**552,410**	**765,932**	**717,237**	**727,940**	**747,730**	**768,180**	**734,316**
Ending Reserve Available for Capital	**6,014,113**	**2,567,650**	**5,725,148**	**142,408**	**4,561,520**	**772,111**	**366,490**
DEBT SERVICE % OF GROSS OPERATING REVENU	**11%**	**11%**	**13%**	**15%**	**14%**	**13%**	**15%**
RESIDENTIAL BILL FOR 1 ERU (or .25 acre)	**4.49**	**4.94**	**5.43**	**5.97**	**6.51**	**6.90**	**7.25**

STORMWATER CIP BUDGET
Five Year Projected Budget FY2020 -2024

COST CENTER	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	CRITICALITY RATING	CONDITION RATING	PAST YEAR 2018-19 (Calc'd from P6)	BUDGET YEAR 2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
53-10301	2720.05		**LIFT STATIONS**									
10301	53471046	2015-0434	LIFT STATION REHABILITATION AT 400 WEST AND 1300 SOUTH - NORTH SIDE	5	4	171,097						400,000
10301	53470852		LIFT STATION AT SURPLUS CANAL AND INDIANA REPAIRS	4	5	7,501						
10301	53471040		SWEDE TOWN LIFT STATION	3	0	40,514		700,000				
10301	534710104	2015-0435	VARIOUS PUMP STATIONS	5	5	50,000	50,000	50,000	50,000	50,000		
10301	53471038	2015-0140	OIL DRAIN LIFT STATION - GABION BASKETS RECONSTRUCTION	5	4	0						58,000
10301	534710103	2015-0135	SD LIFT STATION AT 650 WEST AND 500 NORTH IMPROVEMENTS	4	4	15,000	14,000					107,500
10301		2015-0144	HARTLAND LIFT STATION ABANDONMENT	1	5	0						50,000
10301		2015-0145	300 WEST 1300 SOUTH LIFT STATION ABANDONMENT	1	2	0						50,000
						$ 284,112	$ 64,000	$ 750,000	$ 50,000	$ 50,000	$ -	$ 665,500
53-10301	2730.20		**DETENTION BASINS**									
53-10301	2730.12		**COLLECTION MAINS**									
	53470882	2017-2101	LEE DRAIN - PIPE OPEN CHANNEL WEST OF PIONEER ROAD	5	4	60,000		700,000				
	53470974		ORANGE STREET STORM DRAIN - NORTH TEMPLE TO I-80	5	0	45,000						500,000
	53470835	2015-0142	MIDDLE BRIGHTON RAILROAD CULVERT REHABILITATION	5	4	0		20,000				260,000
		2017-2034	RED BUTTE CREEK CULVERT AT 900 SOUTH - LINER	5	4	0					300,000	
	534701001	2017-2100	PIPE REPLACEMENT AT 750 S 1100 EAST	4	5	3,000						
	534700998	2016-0746	ABANDONMENT OF STORMWATER DITCH FROM WARM SPRINGS ROAD TO THE NORTHWEST DRAIN	4	4	10,000	60,000	250,000				
	534700997	2017-2098	PIPE REPLACEMENT AT 746 SOUTH ELIZABETH	3	5	5,250						
		2015-0131	REPAIR OUTLETS ON THE LEE DRAIN AT 4800 WEST	3	4	0			21,000	170,000		
	53470970	2016-0853	DITCH BANK EROSION PROTECTION - 600 NORTH 550 WEST	2	3	6,039	10,000	60,000				
	53470937	2015-0130	WQ - MONTAGUE CUTOFF- NEW 18" STORM DRAIN	4	0	0						61,500
		2015-0584	FOOTHILL DRIVE (2800 E) – EMIGRATION CREEK TO 2300 EAST	4	0	0						500,000
	53470881	2015-0143	1500 EAST STORM DRAIN	3	0	0				203,000		
	534701000	2016-0750	1700 SOUTH STORM DRAIN, FROM 2100 EAST TO EMIGRATION CREEK	3	0	211,811	1,100,000	1,100,000				
		2015-0585	600 EAST – 900 SOUTH TO THE AVENUES	2	0	0						4,200,000
	53470995		PARLEY CREEK STORM WATER OUTFALL			11,766						
	53470994		CITY DRAIN CROSSING AT HUNTER STABLES			259,175						
	534701013		1700 S 18" STORM DRAIN FROM 1700 E TO 1900 E			399,000						
	53470988		7200 WEST AND NORTH TEMPLE CULVERT REPLACEMENT AND CANAL REHAB			0	250,000					
		2016-0855	NORTHWEST QUADRANT STORMWATER BETTERMENTS	5	5	0						14,000,000
		2018-1040	PIPING OF GOGGIN DRAIN AT HAROLD GATTY DRIVE	3	4	0						335,300
						$ 1,011,040	$ 1,420,000	$2,130,000	$ 21,000	$ 373,000	$ 300,000	$19,856,800
			CITY, COUNTY, STATE AND MISC. DRIVEN PROJECTS									
	53470979		PROGRAM MANAGEMENT TOOLS	5	5	0	150,000					
10301	53470947	2016-0736	INDIANA AVENUE STORM DRAIN REDWOOD ROAD TO 3400 WEST	4	0	128,175						
10301	53470972		GLADIOLA AVE PHASE 1 - 500 SOUTH TO 900 SOUTH			869,550						
10301	53470946	2015-0436	STORM DRAIN CITY/COUNTY/STATE PROJECTS	5	5	0	150,000	150,000	150,000	150,000	150,000	
10301	534720005	2017-2033	STORMWATER RECIEVING STATION	4	4	9,000	150,000					
10301	53470971	2016-0741	1300 EAST - STORM DRAIN	3	4	377,165	1,200,000					
	53470936	R18-0054	NEW STORM DRAIN ON 5500 WEST FROM 700 SOUTH CUL-DE-SAC TO THE NORTH			111,515	1,500,000					
10301	513000039	2015-0723	SURPLUS CANAL ENCROACHMENT AND PERMITTING	5	5	25,000	50,000	50,000	50,000	50,000	50,000	
			700 SOUTH SD, MIDDLE BRIGHTON TO 5600 WEST			0	800,000	800,000	800,000			
			2700 SOUTH - HIGHLAND TO 20TH EAST			0	250,000					
			1500 SOUTH - REDWOOD TO 2700 WEST			0	800,000					
		s	OVERLAY - VARIOUS			0			750,000	750,000		

STORMWATER CIP BUDGET
Five Year Projected Budget FY2020 -2024

COST CENTER	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	CRITICALITY RATING	CONDITION RATING	PAST YEAR 2018-19 (Calc'd from P6)	BUDGET YEAR 2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
	534700999	2015-0126	700 WEST - 2100 SOUTH TO 1700 SOUTH - PIPING OF OPEN DITCH	4	3	0	1,000,000					
			LOCAL STREET DISTRICT 1 & 7			0	500,000					
			500 EAST - 1700 SOUTH TO 2700 SOUTH			0	800,000					
			2000 EAST - PARLEY'S TO CITY LIMIT			0	250,000					
			900 SOUTH - 900 WEST TO 300 WEST, WEST TEMPLE TO 900 EAST			0	1,000,000					
			300 WEST - 900 SOUTH TO 2100 SOUTH			0		550,000	550,000			
			900 EAST - HOLLYWOOD TO 2700 SOUTH			0		1,300,000				
			100 SOUTH - NORTH CAMPUS DRIVE TO 900 EAST			0		275,000				
			LOCAL STREETS DISTRICT 3 & 6			0		500,000				
			200 SOUTH - 400 WEST TO 900 EAST			0			125,000	125,000		
			LOCAL STREETS DISTRICTS 2 & 5			0			625,000			
			1100 EAST HIGHLAND , RAMONA TO WARNOCK			0				2,200,000		
			1100 EAST - 900 SOUTH TO RAMONA			0				900,000		
			1700 EAST - 1700 SOUTH TO 2700 SOUTH			0				875,000		
			300 NORTH - 300 WEST TO 1000 WEST			0				250,000		
			LOCAL STREETS DISTRICT 4 & 7			0				500,000		
			VIRGINIA STREET - SOUTH TEMPLE TO 11TH AVE			0					1,700,000	
			1300 EAST - 2100 SOUTH TO 3000 SOUTH			0					550,000	
			W TEMPLE - NORTH TEMPLE TO 400 SOUTH			0					250,000	
			LOCAL STREETS 3 & 6			0					500,000	
			2100 SOUTH - 700 EAST TO 1700 EAST			0						2,000,000
			LOCAL STREETS DISTRICT 1, 4 & 5			0						500,000
		Bond Alternativ	GLADIOLA STREET - 900 SOUTH TO CALIFORNIA			0						
		Bond Alternativ	300 WEST - 400 SOUTH TO 900 SOUTH			0						
		Bond Alternativ	WAKARA WAY - FOOTHILL DRIVE TO CHIPETA WAY			0						
						$ 1,520,406	$ 8,600,000	$3,625,000	$3,050,000	$5,800,000	$3,200,000	$ 2,500,000
			PUBLIC UTILITY DEFINED PROJECTS									
	534701008	2016-1200	CLEAN OUT REHABILITATION 2018/19	4	5	75,000	100,000	100,000	100,000	100,000	100,000	
10301	53470977		NORTHWEST DRAIN - IMPROVE BOOM DEPLOYMENT LOCATION AT BOY SCOUT DRIVE	5	3	15,000						
10301		2016-1270	URBAN WETLAND TREATMENT FACILITY AT FAIRMONT PARK - PRE-DESIGN	3	0	0		20,000				
10301		2016-0854	GREEN INFRASTRUCTURE AT HOOTEN BUILDING -ROOF DRAIN INFILTRATION	2	0	0	10,000	30,000				
10301	53470973	2016-1086	STORM WATER QUALITY - DESIGN FOR MAJOR OUTFALLS	3	0	100,000	100,000	100,000				
10301		2015-0132	WQ - WETLANDS TREATMENT FACILITY AT BOY SCOUT DRIVE	1	0	0						1,000,000
						$ 190,000	$ 210,000	$ 250,000	$ 100,000	$ 100,000	$ 100,000	$ 1,000,000
			RIPARIAN CORRIDOR PROJECTS									
10301	534926		EMIGRATION IMPROVEMENTS @ BONNEVILLE GOLF COURSE R03A,RO3B,RO4,RO5A,R05B	4	4	9,459						
10301	53473027	2015-0138	WQ - ROTARY PARK RCO IMPROVEMENTS AND WATER QUALITY FEATURE	4	3	0		250,000				
	STW-1		LEM_R02B , LOWER HOGLE ZOO	3	4	0		25,000	300,000			
10301	534922	2015-0581	LRB_L05A: VA MEDICAL CENTER – BELOW FOOTHILL DRIVE	2	4	0						121,000
10301	534912	2015-0560	UCC_R11C: GUARD SHACK GATE AREA	2	4	0						195,000
10301	534920	2015-0556	UCC_R11A: ELBOW TURN	2	4	0						80,000
10301	534910	2015-0559	LCC_R01B: UPPER FREEDOM TRAIL AREA	2	4	0						164,500
10301	534911	2015-0557	LCC_R01C: LOWER FREEDOM TRAIL AREA	2	4	0						150,000
10301	534918	2015-0578	LCC_R01D02A: UPPER MEMORY GROVE PARK	2	4	0						180,000
10301	534919	2015-0579	LRB_R03: UNIVERSITY – ABOVE CHIPETA WAY	2	4	0						85,000
10301	534923	2015-0582	LRB_R02: UNIVERSITY – BELOW RED BUTTE GARDEN	2	4	0						85,000
10301		2015-0580	UEM_R17: ABOVE DEBRIS BASIN (ROTARY PARK)	2	4	0						10,000
10301		2015-0577	LPC_R05C: MIDDLE SUGARHOUSE PARK	2	4	0						250,000

STORMWATER CIP BUDGET
Five Year Projected Budget FY2020 -2024

COST CENTER	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	CRITICALITY RATING	CONDITION RATING	PAST YEAR 2018-19 (Calc'd from P6)	BUDGET YEAR 2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
10301		2015-0576	LPC_R05B: SUGARHOUSE PARK – HEAR HIGHLAND HIGH TRACK	2	4	0						130,000
10301		2015-0575	LPC_R05A: UPPER SUGARHOUSE PARK	2	4	0						160,000
10301		2016-1201	1700 SOUTH STORM WATER TREATMENT FACILITY	3	0	0			250,000			250,000
10301	53471050	2015-0141	WQ - 10TH NORTH LIFT STATION WATER QUALITY IMPROVEMENTS	5	0	88,652	1,700,000					
10301		2015-0136	LRB_R05C; SUNNYSIDE PARK	1	1	0						173,000
10301		2015-0610	RED BUTTE AT 1300 EAST - RIPARIAN ENHANCEMENTS	2	0	0						10,000
10301	534928	2015-0721	RIPARIAN CORRIDOR SIGNS	2	0	0						50,000
10301		2015-0466	LEM_R03A: BONNEVILLE GOLF COURSE - UPPER	3	3	0						127,000
10301		2015-0467	LEM_R04: BONNEVILLE GOLF COURSE - BELOW STORM DRAIN OUTLET GULLY	3	3	0						200,000
10301		2015-0558	LEM_R01: ROTARY GLEN PARK	2	4	0						16,000
10301		2017-2085	CORNELL LIFT STATION WATER QUALITY IMPROVEMENTS - CONSTRUCTION	2	0	0						700,000
						$ 98,111	$ 1,700,000	$ 275,000	$ 550,000	$ -	$ -	$ 3,136,500
			LOCAL AREA PROJECTS (* WORK BY CITY CREWS)									
10301	534701007	2015-0437	VARIOUS PROJECTS	5	5	100,000	100,000	100,000	100,000	200,000	200,000	
10301	534701006	2015-0439	AVENUE CROSSWALKS / SID VARIOUS STREETS -DIP STONE REPLACEMENT	3	4	50,000	50,000	50,000	50,000	50,000	50,000	
10301	534701005	2015-0440	AVENUE CROSSWALKS AND ADA RAMPS	3	0	50,000	50,000	50,000	50,000	50,000	50,000	
10301	534701004	2015-0438	CONTRIBUTIONS BY DEVELOPERS	3	0	400,000	400,000	400,000	400,000	400,000	400,000	
	53475005		STORM DRAIN BOX DECK REPLACEMENT 2017/2018			79,385						
						$ 679,385	$ 600,000	$ 600,000	$ 600,000	$ 700,000	$ 700,000	$ -
			MASTER PLAN PROJECTS									
		2016-0776	MP35 CULVERT UPGRADES	3	5	0						190,400
		2016-0979	NORTH JOHN GLENN NEW 48 " LINE	4	4	0						3,480,000
		2016-1195	BECK STREET TRUCK REPLACEMENT FROM 200 SOUTH AND 300 WEST TO STATE STREET AND 500 SOUTH	4	3	0						5,449,951
		2016-0758	MP2 FOOTHILL CULVERT - EMIGRATION CREEK AT 2100 EAST	3	3	0						3,000
		2016-0800	MP66 PIPE UPSIZE	3	3	0						16,200
		2016-0788	MP51 EMIGRATION CREEK CHANNEL	3	3	0						22,000
		2016-0789	MP52 NEW 1700 EAST STORM DRAIN	3	3	0						31,000
		2016-0796	MP60 NEW PIPE AND OUTFALL	3	3	0						32,300
		2016-0770	MP21 200 GATSBY POWER PLANT	3	3	0						42,000
		2016-0759	MP3 SUGARHOUSE PARK TELEMETRY	3	3	0						50,000
		2016-0760	MP6 1700 S DETENTION BASIN TELEMETRY	3	3	0						50,000
		2016-0797	MP62 WYOMING STORM DRAIN	3	3	0						51,000
		2016-0805	MP75 PIPE UPSIZE	3	3	0						57,900
		2016-0798	MP63 PIPE UPSIZE	3	3	0						63,200
		2016-0809	MP82 400 SOUTH UPSIZE	3	3	0						63,800
		2016-0801	MP67 PIPE CAPACITY UPGRADES	3	3	0						85,800
		2016-0811	MP84 PIPE UPSIZE	3	3	0						94,200
		2016-0795	MP59 I-80/I-215 DETENTION BASIN	3	3	0						95,000
		2016-0814	MP88 NEW STORM DRAIN COLLECTOR	3	3	0						112,488
		2016-0799	MP64 PIPE UPSIZE	3	3	0						131,700
		2016-0807	MP78 PIPE UPSIZE	3	3	0						170,000
		2016-0784	MP46 SOUTH TEMPLE/FOLSOM AVENUE STREET RECONSTRUCTION	3	3	0						178,000
		2016-0802	MP69 PIPE UPSIZE	3	3	0						198,200
		2016-0806	MP76 NEW STORM DRAIN COLLECTOR	3	3	0						219,785
		2016-0787	MP50 9TH AVENUE STORM DRAIN	3	3	0						267,000
		2016-0808	MP79 WASATCH DRIVE IMPROVEMENTS	3	3	0						173,000

STORMWATER CIP BUDGET
Five Year Projected Budget FY2020 -2024

COST CENTER	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	CRITICALITY RATING	CONDITION RATING	PAST YEAR 2018-19 (Calc'd from P6)	BUDGET YEAR 2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
		2016-0780	MP39 NEW DETENTION BASIN	3	3	0						225,100
		2016-0815	MP89 NEW STORM DRAIN COLLECTOR	3	3	0						243,348
		2016-0782	MP42 REDWOOD ROAD AND CWA NO. 4	3	3	0						321,100
		2016-0777	MP36 LEE DRAIN IMPROVEMENTS	3	3	0						333,200
		2016-0771	MP24 200 EAST IMPROVEMENTS	3	3	0						333,548
		2016-0812	MP85 PIPE UPSIZE	3	3	0						360,300
		2016-0761	MP7 400 SOUTH PUMP STATION	3	3	0						378,500
		2016-0804	MP74 PIPE UPSIZE	3	3	0						387,000
		2016-0765	MP15 LIBERTY PARK DETENTION BASIN	3	3	0						391,899
		2016-0793	MP57 BRIGHTON DRAIN CHANNEL IMPROVEMENTS	3	3	0						452,200
		2016-0769	MP20 DETENTION BASIN - 800 SOUTH 4050 WEST	3	3	0						455,000
		2016-0810	MP83 LAURELHURST DRIVE IMPROVEMENTS	3	3	0						501,000
		2016-0773	MP28 I STREET CONDUIT	3	3	0						502,986
		2016-0772	MP27 BRIGHTON DRAIN CHANNEL IMPROVEMENTS	3	3	0						561,400
		2016-0778	MP37 NEW CHANNEL AND DETENTION BASIN	3	3	0						609,000
		2016-0786	MP49 500 SOUTH IMPROVEMENTS	3	3	0						635,592
		2016-0767	MP17 DETENTION BASIN AND CHANNEL	3	3	0						714,000
		2016-0766	MP16 CHANNEL TO I-80 INTERCHANGE	3	3	0						718,200
		2016-0791	MP54 CWA NO. 4 (1400 WEST) AT 200 SOUTH	3	3	0						728,900
		2016-0794	MP58 LEE DRAIN IMPROVEMENTS	3	3	0						729,400
		2016-0790	MP53 FOOTHILL DRIVE STORM DRAIN	3	3	0						774,000
		2016-0779	MP38 LEE DRAIN IMPROVEMENTS	3	3	0						778,600
		2016-0762	MP11 DETENTION BASIN OVERFLOW	3	3	0						807,300
		2016-0803	MP71 INTERSECTION CROSS DRAIN UPGRADES	3	3	0						1,065,000
		2016-0781	MP40 EAST BENCH AND FEDERAL HEIGHTS IMPROVEMENTS	3	3	0						1,152,532
		2016-0813	MP87 CWA NO. 1 IMPROVEMENTS	3	3	0						1,287,200
		2016-0764	MP13 EMIGRATION CONDUIT	3	3	0						1,308,000
		2016-0768	MP18 UNDERSIZED CULVERTS, CHANNEL IMPROVEMENTS, DETENTION BASIN	3	3	0						1,352,600
		2016-0785	MP47 PIPELINE FROM BECK STREET	3	3	0						1,693,643
		2016-0783	MP44 CWA NO. 2 AT I-80 NORTH TEMPLE OFF RAMP/AIRPORT DETENTION BASIN	3	3	0						2,031,000
		2016-0774	MP29 VARIOUS IMPROVEMENTS	3	3	0						2,114,200
		2016-0775	MP32 600 EAST CONDUIT	3	3	0						2,540,522
		2016-0763	MP12 900 SOUTH CONDUIT	3	3	0						12,626,142
		2016-0757	MP1 UPPER DRY CREEK DETENTION BASIN	3	0	0						616,000
						$ -	$ -	$ -	$ -	$ -	$ -	$51,056,336
			TOTAL COLLECTION LINES			$ 3,498,941	$12,530,000	$6,880,000	$4,321,000	$6,973,000	$4,300,000	$77,549,636
	2730.20		**LANDSCAPING**									
10301	53470934		NORTHWEST OIL DRAIN			0	150,000					
						$ -	$ 150,000	$ -	$ -	$ -	$ -	$ -
			TOTAL CAPITAL IMPROVEMENTS			$ 3,783,053	$12,744,000	$7,630,000	$4,371,000	$7,023,000	$4,300,000	$78,215,136

STORMWATER UTILITY CAPITAL PURCHASES BUDGET
Five Year Projected Budget FY2020-2024

COST CENTER	OBJECT CODE	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	Comments	CRITICALITY RATING	CONDITION RATING	PAST YEAR 2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
53-10201	2710.10			LAND										
								$ -	$ -	$ -	$ -	$ -		$ -
								0	0	0	0			0
	2750.10			MOTIVE REPLACEMENT AUTO & TRUCK										
				VARIOUS						400,000	400,000	400,000	400,000	
5310701	2750.10			3/4 TON TRUCK EXTENDED CAB WITH CABIN CHASSIS 4X4										
5310201	2750.10			3/4 TON TRUCK 4X4										
5310701	2750.10			3/4 TON W/UTILITY BED 4X4										
5310701	2750.10			3/4 TON W/UTILITY BED 4X4`				28,961						
5310201	2750.10		36840	FORD 1 TON CAB-N-CHASSIS WITH DUMP BED				28,961						
5310201	2750.10		36900	GMC 3/4 TON 4WD PICK-UP				34,498						
5310201	2750.10		33520	ESCAPE SUV				23,500						
5310201	2750.10			CLUB CAR CARRY ALL 500 (4)				52,632						
5310201	2750.10			10 WHEEL DUMP TRUCK										
5310301	2750.10			CHEV OR SIMILAR MID-SIZED 4X4 PICK UP W/BED COVER	Jason				30,000					
5310201	2750.10		36010	Replace Mack GU713	Randy				455,149					
5310201	2750.10		36080	Replace Ford F250 W/Dump Bed	Randy				41,500					
5310201	2750.10		36150	Replace Mack Granite	Randy				146,000					
								$ 168,552	$ 672,649	$ 400,000	$ 400,000	$ 400,000	$ 400,000	$ -
	2750.30			FIELD MAINTENANCE EQUIPMENT										
				VARIOUS						180,000	180,000	180,000	180,000	
5310201				VACTOR TRUCK				200,000						
5310201				75618000 6"-18" IPS BUTT FUSION MACHINE GAS HIGH FRC CYL (lincludes insert)				52,068						
5310201				CM-958H SED CEMENT MIXER 9 CF HONDA ENGINE				5,597						
5310201				SAND MASTER (SAND BAGGER)				12,241						
5310201				LOAD KING TRAILER 55 TON				69,260						
				CATERPILLAR 420F2 BACKHOE										
				SELF PROPELLED PIPE FUSION MACHINE										
5310201				BACKHOE BUYBACK PROGRAM				9,000						
5310201				TRACK EXCAVATOR W/DOZER BLADE (REPLACE 36870)										
5310201			NEW	LINKBILT AMI 54" ROOT RAKE	Randy				7,000					
5310201			NEW	HAULING PIPE	Randy				8,500					
								$ 348,166	$ 15,500	$ 180,000	$ 180,000	$ 180,000	$ 180,000	$ -
	2760.30			TELEMETERING										
5310201				RADIO REPLACEMENT				40,086						
5310201				VARIOUS				5,000	40,000	40,000	40,000	40,000	40,000	
								$ 45,086	$ 40,000	$ 40,000	$ 40,000	$ 40,000	$ 40,000	$ -
	2760.50			OFFICE EQUIPMENT										
								$ -	$ -	$ -	$ -	$ -		$ -
	2760.90			OTHER EQUIPMENT										
5310201				ENCLOSED TRAILER										
5310201				DUEL REEL AIR COMPRESSOR										
5310201				2 ECO FRIENDLY PUMPS										
5310201				3 AUTOMATIC COMPOSITE SAMPLERS										
5310201				VARIOUS				5,000						
5310201				CEMENT MIXER										
5310201				JETSCAN VIDEO NOZZLE										
5310201				HERBICIDE SPRAYER PUMP SYSTEM										
5310201				60" ROTARY EXCAVATOR MOWER COMPLETE										
								$ 5,000	$ -	$ -	$ -	$ -	$ -	$ -

STORMWATER UTILITY CAPITAL PURCHASES BUDGET
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COST CENTER	OBJECT CODE	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	Comments	CRITICALITY RATING	CONDITION RATING	PAST YEAR 2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
				TOTAL CAPITAL OUTLAY				$ 566,804	$ 728,149	$ 620,000	$ 620,000	$ 620,000	$ 620,000	$ -

Street Lighting Utility- Budget Summary and Cash Flow

STREET LIGHTING UTILITY
ENTERPRISE FUND
BUDGET SUMMARY
FY 2020-2022

SOURCES	ACTUAL 2017-18	AMENDED BUDGET 2018-19	PROJECTED ACTUAL 2018-19	PROPOSED BUDGET 2019-20	FORECAST BUDGET 2020-21	FORECAST BUDGET 2021-22
REVENUES						
STREET LIGHTING FEES	$ 4,198,227	$ 4,170,000	$ 4,198,227	**$ 4,198,227**	$ 4,198,227	$ 4,198,227
INTEREST INCOME	94,979	52,000	52,000	**30,000**	29,000	29,000
OTHER REVENUES	2,991	9,000	11,000	**9,000**	9,000	9,000
TOTAL REVENUES	$ 4,296,197	$ 4,231,000	$ 4,261,227	**$ 4,237,227**	$ 4,236,227	$ 4,236,227
OTHER SOURCES						
GRANTS & OTHER RELATED REVENUES	195,808	-	-	**-**	-	-
TRANSFERS FROM GENERAL FUND	20,000	20,000	20,000	**20,000**	20,000	20,000
IMPACT FEES	-	-	-	**-**	-	-
BOND PROCEEDS	-	-	-	**-**	-	-
T O T A L OTHER SOURCES	215,808	20,000	20,000	**20,000**	20,000	20,000
T O T A L SOURCES	$ 4,512,005	$ 4,251,000	$ 4,281,227	**$ 4,257,227**	$ 4,256,227	$ 4,256,227
EXPENSES & OTHER USES						
EXPENDITURES						
PERSONNEL SERVICES	$ 206,367	$ 198,307	$ 198,307	**$ 281,575**	$ 292,836	$ 304,548
OPERATING & MAINTENANCE	462	7,300	7,300	**7,300**	7,446	7,596
TRAVEL & TRAINING	1,368	3,000	3,000	**3,000**	3,060	3,121
UTILITIES	850,841	990,900	990,900	**1,010,900**	970,422	937,223
TECHNICAL SERVICES	1,035,264	1,720,028	1,720,028	**1,638,204**	1,523,964	1,503,287
DATA PROCESSING	1,117	-	-	**-**	-	-
FLEET MAINTENANCE	-	-	-	**-**	-	-
ADMINISTRATIVE SERVICE FEE	32,450	20,000	20,000	**20,000**	20,400	20,808
PAYMENT IN LIEU OF TAXES	-	-	-	**-**	-	-
RISK MANAGEMENT	-	-	-	**-**	-	-
TRANSFERS TO GENERAL FUND	-	-	-	**-**	-	-
OTHER CHARGES AND SERVICES	14,017	2,406	2,406	**2,298**	2,613	2,665
TOTAL EXPENDITURES	2,141,886	2,941,941	2,941,941	**2,963,277**	2,820,741	2,779,248
OTHER USES						
CAPITAL OUTLAY	-	-	-	**-**	-	-
CAPITAL IMPROVEMENT BUDGET	1,898,666	2,621,414	2,605,000	**1,725,000**	2,360,000	2,025,000
DEBT SERVICES	105,927	103,000	103,000	**103,000**	191,000	190,000
T O T A L OTHER USES	$ 2,004,593	$ 2,724,414	$ 2,708,000	**$ 1,828,000**	$ 2,551,000	$ 2,215,000
T O T A L USES	$ 4,146,479	$ 5,666,355	$ 5,649,941	**$ 4,791,277**	$ 5,371,741	$ 4,994,248
EXCESS REVENUE AND OTHER SOURCES OVER (UNDER) USES	$ 365,526	$ (1,415,355)	$ (1,368,714)	**$ (534,050)**	$ (1,115,514)	$ (738,021)
OPERATING CASH BALANCES						
BEGINNING JULY 1	$ 5,472,718	$ 5,838,244	$ 5,838,244	**$ 4,469,530**	$ 3,935,480	$ 2,819,966
ENDING JUNE 30	$ 5,838,244	$ 4,422,889	$ 4,469,530	**$ 3,935,480**	$ 2,819,966	$ 2,081,945
Cash Reserve Ratio	273%	150%	152%	132.8%	100.0%	74.9%

Cash reserve goal above 10%

STREET LIGHTING UTILITY
CASH FLOW
FY 2020 BUDGET
AND FY 2021-2024 FORECAST

	Actual YEAR 2017-2018	Projected YEAR 2018-2019	BUDGET YEAR 2019-2020	BUDGET YEAR 2020-2021	BUDGET YEAR 2021-2022	BUDGET YEAR 2022-2023	BUDGET YEAR 2023-2024
STREET LIGHTING SALES	4,198,227	4,198,227	4,198,227	4,198,227	4,198,227	4,198,227	4,198,227
OTHER INCOME	2,991	11,000	9,000	9,000	9,000	9,000	9,000
INTEREST INCOME	94,979	52,000	30,000	29,000	29,000	29,000	29,000
OPERATING INCOME	4,296,197	4,261,227	4,237,227	4,236,227	4,236,227	4,236,227	4,236,227
OPERATING EXPENSES	(2,141,886)	(2,941,941)	(2,963,277)	(2,820,741)	(2,779,248)	(2,840,922)	(2,904,074)
NET INCOME EXCLUDING DEP.	2,154,311	1,319,286	1,273,950	1,415,486	1,456,979	1,395,305	1,332,153
BOND PROCEEDS	-	-	-	-	-	-	-
OTHER CONTRIBUTIONS	215,808	20,000	20,000	20,000	20,000	20,000	20,000
CAPITAL OUTLAY	-	-	-	-	-	-	-
DEBT SERVICE	(105,927)	(103,000)	(103,000)	(191,000)	(190,000)	(190,000)	(190,000)
OTHER INCOME & EXPENSE	109,881	(83,000)	(83,000)	(171,000)	(170,000)	(170,000)	(170,000)
GENERATED FOR CAPITAL	2,264,192	1,236,286	1,190,950	1,244,486	1,286,979	1,225,305	1,162,153
CAPITAL IMPROVEMENTS	(1,898,666)	(2,605,000)	(1,725,000)	(2,360,000)	(2,025,000)	(2,025,000)	(1,525,000)
BEGINING CASH BALANCE	5,472,718	5,838,244	4,469,530	3,935,480	2,819,966	2,081,945	1,282,250
CASH INCREASE/(DECREASE)	365,526	(1,368,714)	(534,050)	(1,115,514)	(738,021)	(799,695)	(362,847)
ENDING BALANCE	5,838,244	4,469,530	3,935,480	2,819,966	2,081,945	1,282,250	919,403
RATE CHANGE	0%	0%	0%	0%	0%	0%	0%
Cash Reserve Ratio	272.6%	151.9%	132.8%	100.0%	74.9%	45.1%	31.7%
Debt Service Coverage	20.34	12.81	12.37	7.41	7.67	7.34	7.01
DEBT SERVICE % OF GROSS OP. REV.	2.5%	2.4%	2.4%	4.5%	4.5%	4.5%	4.5%
RESIDENTIAL BILL OF 1 ERU (or 75 ft)	3.73	3.73	3.73	3.73	3.73	3.73	3.73

STREET LIGHTING UTILITY
CIP BUDGET
Five Year Projected Budget 2020-2024

COST CENTER	PROJECT NUMBER	PROJECT DESCRIPTION	CRITICALITY RATING	CONDITION RATING	PAST YEAR SPENT 2018-19	BUDGET YEAR 2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
48-48001	2730.80	**Base Level Projects**									
48001	48135	ARTERIAL & COLLECTOR STREET HE AND SYSTEM UPGRADES	2	4	300,000	300,000	300,000	300,000	300,000		
48001	48126	HIGH WATTAGE REPLACEMENTS				500,000	500,000	500,000	500,000	500,000	2,500,000
48001	48130	NEIGHBORHOOD HE AND SYSTEM UPGRADES	4	4	1,000,000	500,000	500,000	500,000	500,000	500,000	2,500,000
48001	48137	1300 EAST - STREET LIGHTS	3	3							
48001		LOCAL STREET IMPROVEMENT SUPPORT			50,000	200,000	200,000	200,000	200,000	200,000	1,000,000
		LIGHTING CONTROLS				200,000	500,000	500,000	500,000	300,000	
		BASE LEVEL - TOTAL IMPROVEMENTS			$ 1,350,000	$ 1,700,000	$ 2,000,000	$ 2,000,000	$ 2,000,000	$ 1,500,000	$ 6,000,000
48-48101	2730.80	**TIER 1 Projects**									
48101	48131	Tier 1 Capital Replacements			5,000	5,000	5,000	5,000	5,000	5,000	595,000
48101		Tier 1 HE Upgrades					190,000				210,000
		TIER 1 - TOTAL IMPROVEMENTS			$ 5,000	$ 5,000	$ 195,000	$ 5,000	$ 5,000	$ 5,000	$ 805,000
48-48201	2730.80	**TIER 2 Projects**									
48201	48132	Tier 2 Bad Wiring Replacement			365,000						
48201	48139	Tier 2 Capital Replacement			5,000	5,000	5,000	5,000	5,000	5,000	395,000
48201	48133	Tier 2 HE Upgrades			100,000						
		TIER 2 - TOTAL IMPROVEMENTS			$ 470,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 395,000
48-48301	2730.80	**TIER 3 Projects**									
48301	48140	Tier 3 Capital Replacement			15,000	15,000	15,000	15,000	15,000	15,000	2,310,000
48301	48134	Tier 3 HE Upgrades			765,000		145,000				160,000
		TIER 3 - TOTAL IMPROVEMENTS			$ 780,000	$ 15,000	$ 160,000	$ 15,000	$ 15,000	$ 15,000	$ 2,470,000
		TOTAL CAPITAL IMPROVEMENTS			$ 2,605,000	$ 1,725,000	$ 2,360,000	$ 2,025,000	$ 2,025,000	$ 1,525,000	$ 9,670,000

APPENDIX A: Proposed Rate Structure and WRF Resolutions

APPENDIX B: Rationale for New Positions

Proposed New Public Utilities Positions and Organizational Changes for FY 2020 (in alphabetical order)

Community and Engagement (one FTE and Organization Change)

The Department has identified a need for one full time employee to assist with public engagement. This position, Community and Engagement Coordinator, would report to the Community and Engagement Manager, and support all print and television media needs, website, and social media functions. The position would also assist with community feedback and education on the Department's numerous programs, planning efforts, and capital improvement projects. Engagement related to planning and programmatic work includes watershed, water conservation, street lighting, and stormwater master planning. In addition, construction related to large capital projects, such as those related to the new WRF, the East-West Conveyance, and streets bond-related projects will have an impact on the community and require additional engagement.

The Department is proposing to move the Employee Development and Training Coordinator position to report to the Community and Engagement Manager. The Employee Development and Training Coordinator position currently reports to the Department Director.

The Department is proposing to reclassify the Community and Engagement Manager to a slightly higher pay classification to reflect additional management responsibility.

Development Services (one FTE)

The Department has identified the need for a dedicated records technician in the Department's Development Services division. This is due to increased growth throughout the Department's service area, including within Salt Lake City, Cottonwood Heights, Mill Creek, and Holladay. This position will report to the Water Rights, Contracts, and Property Manager, and be responsible for maintaining and updating electronic files, including agreements, plans, general correspondence, and general administration files. This position will also assist with succession planning due to anticipated retirements in this area.

Engineering (five FTEs)

See attached memorandum dated March 20, 2019 from Jason Brown, Chief Engineer to Laura Briefer, Director of Public Utilities.

GIS Leak Detection (one FTE)

The Department has identified a need to add one FTE to support the Department's leak detection program. Currently there is only one position allocated to this task, and therefore no redundancy in this function. The leak detection function allows the Department to identify water loss caused by leaks in the water distribution system. Leaks in the system lead to water waste and lost revenue.

Maintenance and Operations (one FTE)

The Department has identified the need for an additional Senior Water System Maintenance Worker. This position was approved in the Department's FY2019 budget.

However, the Department reclassified this position as a Maintenance Electrician IV in order to address a safety need for our emergency water crews. The Department is in a several year process of converting more than 90,000 water meters in to smart meters across the water service area. The Senior Water System Maintenance Worker is needed specifically to change large meters for industry, business, and institutional properties. This position also supports succession planning in the Maintenance and Operations Division. This employee will report to the Water System Maintenance Supervisors who will report to the Water Distribution System Manager.

Special Projects Manager Reclassification and Water Resources Reorganization

The Department is proposing to reclassify the Special Projects Manager position to a Water Resources Manager position and create a Water Resources Division. The Water Resources Division will be responsible for administering the City's water rights, maintaining water supply and demand data, climate and energy initiatives, and water conservation programs. The Water Resources Manager will report to the Department Director, and oversee the Sustainability, Water Conservation, and Hydrology functions. The purpose of this change is to increase capacity to better address and coordinate recommended actions identified in the Department's updated Water Supply and Demand Plan, Drought Contingency Plan, and Water Conservation Plan. In addition, the state has increased reporting requirements related to water rights, water source sizing, and water loss, which this position and division will manage. Finally, this reorganization facilitates succession planning.

Sustainability (one FTE)

The Department has identified a need for one full time employee to assist with energy management, energy and greenhouse gas reduction, and climate change projects. This position will report to the Water Resources Manager. This Sustainability Manager position is needed to ensure compliance with City energy initiatives and assist the Department with its climate change vulnerability assessments, mitigation, and adaptation planning. This includes the following:

- **The Comprehensive Energy Management Executive Order**: This City Executive Order requires that the Department prepare and implement energy management plans, and places requirements on renovation and new construction of the Department's facilities: http://www.slcinfobase.com/PPAREO/#!WordDocuments/comprehensiveenergymanagementofsaltlakecityfacilities.htm.
- **The Elevate Buildings Commercial Ordinance (Section 18.94.050)**: This City ordinance requires that the Department prepare and submit energy benchmarking information to the Sustainability Department and to the public: http://sterlingcodifiers.com/codebook/index.php?book_id=672&chapter_id=102505
- **Salt Lake City Department of Public Utilities Renewable Energy Plan (2015):** This plan identifies opportunities throughout the Department's infrastructure for the generation of renewable energy.
- **Salt Lake City Department of Public Utilities Wire to Water Efficiency Study (2018)**: This study identifies capital and operational actions that the Department can take to reduce energy use. *The Department has estimated that implementation*

of energy efficiency strategies identified in this study will result in a potential annual cost savings of $200,000, and 4,000,000 kilowatt hours.

- **Salt Lake City Department of Public Utilities Climate Change Vulnerability Assessment and Adaptation Plan (ongoing)**: The Department is in its second year of a five-year scientific study with the University of Utah to identify climate risks related to water supply, water quality, and storm intensification. The study will result in an adaptation plan to mitigate identified climate risks.

Wastewater Pretreatment Program (four FTEs)

The Department's Pretreatment Program is required by Section 403 of the Clean Water Act. The overall mission of the Pretreat Program is to provide protection to the Publicly Owned Treatment Works (POTW), protect the health and safety of collections and treatment staff and the environment from hazardous, toxic, and incompatible pollutant discharge into the sanitary sewer system and also promote the health and safety of the general public by minimizing the potential for sanitary sewer overflow events.

Four additional staff positions are requested for the Pretreatment Program:

- Fats, Oil, and Grease (FOG)/Sewer Rate Program Supervisor
- Pretreatment Inspector/Permit Writer
- Senior Wastewater Sampler/Inspector
- Administrative Assistant (WRF)

These positions are needed for the program to meet the demands of current city growth as well as planned industrial growth in the Northwest Quadrant. New federal wastewater discharge prohibitions have created additional work. Two recent regulatory examples relate to hazardous waste pharmaceuticals and dental amalgam. When compared to programs in cities of similar population and industrial influence, the Department's Pretreatment Program is understaffed. This shortfall was noted by the Utah Division of Water Quality (UDWQ) during their 2018 inspection. The UDWQ inspection findings report stated: "*With the growth of the permitting load and the dental program it is recommended that the city evaluate the need for additional staffing.*"

The FOG/Sewer Rate Program Supervisor will take a proactive role to reduce FOG loading into the collection system. Currently there are areas of the city the Collections team has to clean quarterly due to FOG buildup in the lines. The discharge of FOG material into the collection system can lead to sewer overflow and more rapid degradation of the collection system. The supervisor will also be tasked with ensuring sewer rates are properly assigned to commercial and industrial used based on pollutant loading.

Watershed Program (two Seasonal Positions)

The Department has identified the need for two seasonal watershed worker positions during the summer. Recreation continues to increase in the City's watersheds in City Creek, Parleys, Big Cottonwood, and Little Cottonwood Canyons. This is resulting in potential impacts to water quality. Seasonal watershed workers help with upkeep of restroom

facilities at popular trailheads, stewardship of the Department's preserved lands, and public education under the Keep it Pure program.

TO: Laura Briefer, Director of Public Utilities

BY: Jason Brown, P.E., Chief Engineer

DATE: March 20, 2019

SUBJECT: Request for five additional Engineering staff FTE's for fiscal year 2020

Background, Purpose and Need

The objective of this memorandum is to provide justification and recommendation for additional staff for the Engineering Division within Public Utilities.

The Engineering Division of the Department of Public Utilities has been going through dramatic changes in terms of updating our practices, organization, project elements, and work responsibilities to enhance our services for better accountability, performance, transparency, and efficiency in the delivery of engineering services to the Utility and the public. These changes coupled with changes in the industry have highlighted resource needs and workload stresses in our work environment that impede our ability and capacity for continued successful project delivery.

Summary

We present the following justifications for increasing the in-house staff FTE's for the Engineering group:

(1) The current and past CIP workload justifies more in-house staff.

In 1994 Hughes, Heiss & Associates conducted an audit of the Engineering group. They recommended increasing the staff based on the CIP program funding at that time and concluded that using Consultants to fill in the production gap was not "cost effective". At the time, a reorganization of Engineering was done but no additional staff was added.

The total CIP program for water/sewer/drainage in 1994 when the audit was conducted was under $10M. Currently it is over $170M and the number of FTE's has remained basically the same (Figure 1 & Figure 2). The demands on the current staff are increasing as public outreach, engagement and education are drawing away time that was typically allocated for design and construction. Many of these critical activities we have been able to temper with advances in efficiencies using technologies but even with advances with technology, the technology requires staff time.

(2) In-house staff is less expensive than using Consultants for the CIP workload.

The average cost of the existing Engineering staff including overhead (7.72%) and labor additive (56.36%) is $51.68 per hour. The average hourly cost which will be charged by Consultants for project engineers based on the most recent General Services SOQ's is approximately $150 per hour. Doing work with City staff is approximately a <u>third</u> of the cost of using a Consultant. With new staff positions being limited, we have utilized outside consultants for much of the additional inspection and design. This method allows staff to manage approximately 2 to 4 times the number of projects depending on complexity. However, the costs to design and inspect the projects are generally 3 times more expensive because of reasons stated above.

(3) Aging infrastructure requires additional staff to maintain cost effectiveness.

The CIP budget levels is projected to increase, particularly with the Water Reclamation Plant where a process upgrade project will be required to meet permit requirements for nutrient removal. The Nutrient project is projected to be $528 million over the next 7 years. The other programs (water/sewer/drainage/lighting) are also showing increased budget funding requirements due to aging infrastructure and regulatory requirements. Assuming 10% design/construction management cost and 30% vacation/sick/holiday discount, this CIP program will require 36 FTE's. The current staff level is 27.72 FTE's. The gap is currently being supplemented through consultant contracts, but as additional condition assessments have been completed, we are finding that the breadth of improvements necessary to maintain a high level of service to the community is expanding.

(4) To reduce inspector overtime.
The overtime cost for inspectors in 2018 was $137k. Converting this cost to full time FTE's equates to 1.5 additional inspector FTE.

<u>RECOMMENDATION</u>

We are requesting the addition 5 of FTE's to the Engineering group based on the analysis discuss above. Specifically, we are recommending the following changes to the staffing document as outlined below.

<u>New Staff Positions</u>

+3 E Tech II	E Tech II to support development in the Department service area, including Salt Lake County and the Northwest Quadrant.
Justification	Based on current workload needs to assist in the inspection and drafting. Roughly 1/3 the cost will be to have in-house inspection rather than consultant contracted inspection. This can become a cost savings for the Department. Having internal staff inspect infrastructure has the added benefit of knowledge retention within the department rather than the external consultant. In addition, many of the existing inspection staff are approaching retirement age and hiring newer staff is in line with succession planning within the department.
+2 Eng II/II	Project Engineer/Development Review Engineer
Justification	As with the inspectors having internal staff design, manage and review the upcoming CIP projects will benefit the department with reducing the costs associated with having external consultants design, manage and review. The additional staff will also tackle the projected workload, aging infrastructure and regulatory requirements.

Below are two figures illustrating the relative need and impact of the City's robust capital improvement program. These are anecdotal but support the business case and workplan justification described above.

NET CHANGE = +6 FTE by 5 new staff positions and reassignment of one staff position

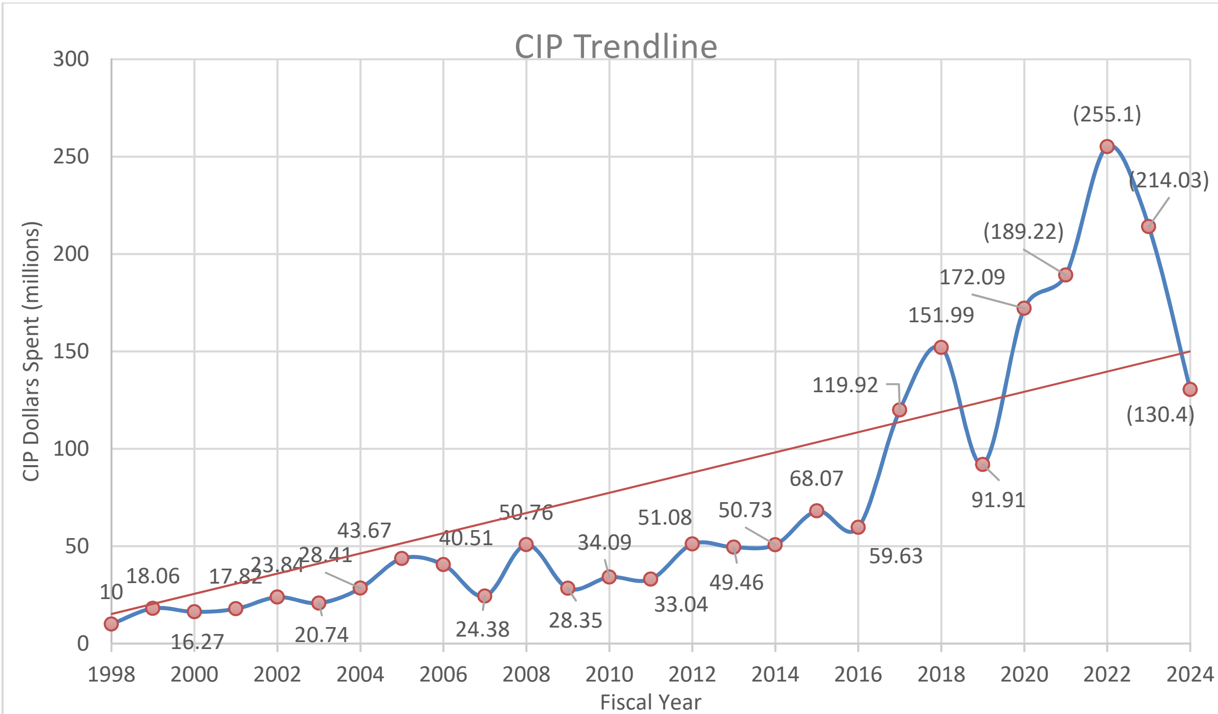


Figure 1 – CIP Trend line

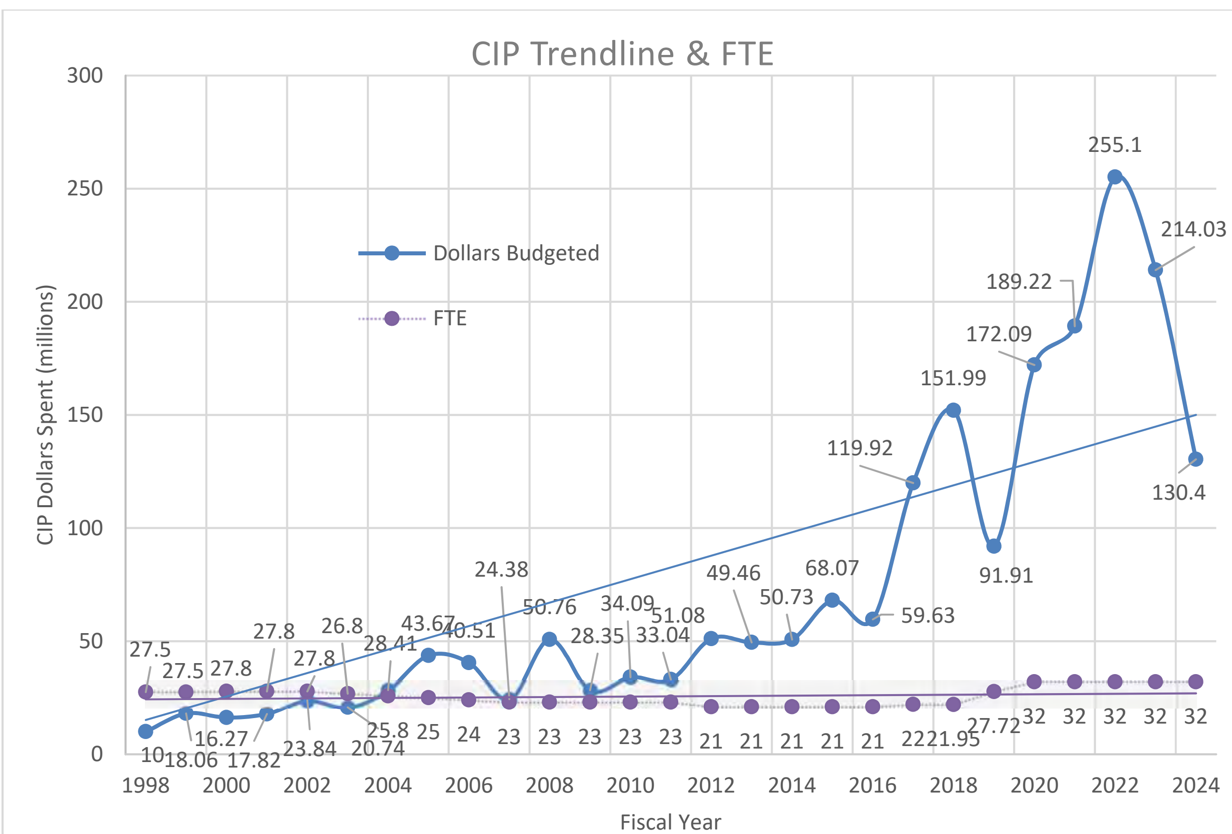


Figure 2 – CIP vs. Engineering group FTE staffing level

APPENDIX C: Public Utilities' Energy Management and Greenhouse Gas Mitigation Projects

Public Utilities Energy Management and Greenhouse Gas Mitigation Projects

Environmental sustainability is at the root of the Department of Public Utilities' legacy and public ethic. Indeed, the Department's mission statement is "serving our community, protecting our environment." The Department has been a steward of water resources serving the Salt Lake Valley for more than a century. Public Utilities later took on the role of protecting public health and the environment through wastewater treatment and stormwater systems and developing street lighting as a self-sustaining utility.

One major component of this legacy is actively addressing the Department's energy use and greenhouse gas emissions, as climate change will have significant implications for Public Utilities' capacity to provide water services to its customers. Mayor Biskupski requested each City Department include as part of its FY2020 budget a demonstrated reduction of greenhouse gas emissions. The Department is providing a summary of efforts identified in the recommended budget that will contribute to this goal.

There are several City policies and goals that drive the Department's efforts regarding energy efficiency, greenhouse gas reduction, and other sustainability practices. These policies include:

- Comprehensive Energy Management of Salt Lake City Facilities Executive Order
- LEED Design Standards Executive Order
- Net-Zero Energy Buildings Executive Order
- Climate Positive 2040
- Elevate Buildings Ordinance

In addition to these governing City policies, the Department has also developed a Public Utilities Energy Policy to guide energy efficiency efforts for all operations and capital projects:

> *SLCDPU uses energy wisely while continuing to exceed the expectations of those we serve. We implement prudent and environmentally responsible strategies and programs in our facilities and operations that minimize our energy use without sacrificing service reliability.*

The FY2020 recommended budget includes funding, both operational and capital, for several efforts that support the Department's Energy Policy and various City goals, ordinances, and Executive Orders. These projects have been identified in the Capital Plans for all enterprise funds. Each identified project has a sustainability component that will contribute to the fulfillment of the various requirements. Examples include:

- A Wire-to-Water Energy Efficiency Study was completed in January 2019 and identified an energy savings potential of 12%. This savings percentage translates to approximately $200,000 and 4,000,000 kWh per year with all capital and operation improvements identified and recommended in the study. Five key projects were identified in the study whose implementation would result in 2,600

metric tons per year of avoided carbon emissions at an initial capital cost of $2,525,000 with a 5.7-year payback period.

    - Select Sources According to Energy Requirements
    - Implement a Leak Detection Program
    - Preserve Pressure from Parley's Water Treatment Plant
    - Install Flow Meters at Pump Stations
    - Optimize the Military Pump Station

- Within the Water Utility, the major upgrade projects at each of the three drinking water treatment plants will consider energy efficiency, reduction of greenhouse gases, and compliance with all executive orders and initiatives. There are also several other Water Utility capital projects that will contribute to the Department's overall sustainability goals, including pump and motor upgrades, the AMI meter replacement program, and designated funding to address specific projects recommended in the Wire-To-Water Energy Efficiency Study. The Parley's Canyon hydropower project design is budgeted for FY 2020, with completion anticipated by 2022. At this time, it is anticipated the project will provide a renewable energy source that is anticipated to generate $126,600 per year in revenue.
- The Sewer Utility also includes several projects in the Capital Plan that will meet sustainability goals, including pump replacements, upgrades to existing reclamation facility, inflow and infiltration studies, and flow meter installation. Most significantly, the design of the new Water Reclamation Facility includes a Sustainability Task Force that is dedicated to the analysis and implementation of energy efficiency/greenhouse gas reduction improvements throughout the occupied buildings and process components of the plant.
- There are several lift station rehabilitation and abandonment projects identified in the Stormwater Capital Plan that will contribute to the achievement of sustainability goals. Rehabilitation projects may entirely replace the pumps and motors or significantly repair these components to reduce overall energy use of the lift station. The abandonment projects will remove a source of energy use altogether, again creating a positive effect on the Stormwater Utility's sustainability impact.
- The goal of the Street Lighting Utility is to have all street lights equipped with energy efficient technology by 2023. The Utility is on track to meet this goal. Data from 2018 indicates that more than 60% of street lights are energy efficient with approximately 3,580,650 kWh in savings since 2014. The high efficiency upgrade projects in the Capital Plan are planned solely to meet the energy efficiency goals for the Street Lighting Utility.

APPENDIX D: Rate Change Comparisons and Customer Impacts

Water Rate Change Comparisons

Comparison of Monthly Water Base Rate Options for City Customers

Meter Size (inches)	2019 Current Rate	2019 Rate Study	2020 Proposed Rate	Changes: Current to Rate Study $	Changes: Current to Rate Study %	Changes: Rate Study to Proposed $	Changes: Rate Study to Proposed %	Changes: Current to Proposed $	Changes: Current to Proposed %
3/4	9.89	8.84	9.28	-1.05	-11%	0.44	5%	-0.61	-6%
1	9.89	11.56	12.14	1.67	17%	0.58	5%	2.25	23%
1 1/2	11.68	18.37	19.29	6.69	57%	0.92	5%	7.61	65%
2	12.68	26.55	27.88	13.87	109%	1.33	5%	15.20	120%
3	21.28	48.34	50.76	27.06	127%	2.42	5%	29.48	139%
4	22.78	72.86	76.50	50.08	220%	3.64	5%	53.72	236%
6	32.89	140.98	148.03	108.09	329%	7.05	5%	115.14	350%
8	59.11	222.71	233.85	163.60	277%	11.14	5%	174.74	296%
10	109.63	576.91	605.76	467.28	426%	28.85	5%	496.13	453%

Comparison of Monthly Water Base Rate Options for County Customers

Meter Size (inches)	2019 Current Rate	2019 Rate Study	2020 Proposed Rate	Changes: Current to Rate Study $	Changes: Current to Rate Study %	Changes: Rate Study to Proposed $	Changes: Rate Study to Proposed %	Changes: Current to Proposed $	Changes: Current to Proposed %
3/4	13.35	11.93	12.53	-1.42	-11%	0.59	5%	-0.82	-6%
1	13.35	15.61	16.39	2.25	17%	0.78	5%	3.04	23%
1 1/2	15.77	24.80	26.04	9.03	57%	1.24	5%	10.27	65%
2	17.12	35.84	37.64	18.72	109%	1.80	5%	20.52	120%
3	28.73	65.26	68.53	36.53	127%	3.27	5%	39.80	139%
4	30.75	98.36	103.28	67.61	220%	4.91	5%	72.52	236%
6	44.40	190.32	199.84	145.92	329%	9.52	5%	155.44	350%
8	79.80	300.66	315.70	220.86	277%	15.04	5%	235.90	296%
10	148.00	778.83	817.78	630.83	426%	38.95	5%	669.78	453%

*Rate Study column is the Department's 2018 Comprehensive Water, Sewer and Stormwater Rate Study proposed change over the current rate column. The proposed rate is the proposed increase on top of the rate study rates

Comparison of Water Monthly Usage Rate Options for City Residential Customers

Flat Rate or Block	2019 Current Rate per ccf	2019 Rate Study per ccf	2020 Proposed Rate per ccf	Changes: Current to Rate Study $	Current to Rate Study %	Rate Study to Proposed $	Rate Study to Proposed %	Current to Proposed $	Current to Proposed %
Winter Rate Structure (November - March)									
Flat Rate	1.35	1.30	1.37	-0.05	-4%	0.07	5%	0.02	1%
Summer Rate Structure (April - October)									
Block 1	1.35	1.30	1.37	-0.05	-4%	0.07	5%	0.02	1%
Block 2	1.85	1.78	1.87	-0.07	-4%	0.09	5%	0.02	1%
Block 3	2.57	2.47	2.59	-0.10	-4%	0.12	5%	0.02	1%
Block 4	2.74	2.63	2.76	-0.11	-4%	0.13	5%	0.02	1%

Comparison of Water Monthly Usage Rate Options for County Residential Customers

Flat Rate or Block	2019 Current Rate per ccf	2019 Rate Study per ccf	2020 Proposed Rate per ccf	Changes: Current to Rate Study $	Current to Rate Study %	Rate Study to Proposed $	Rate Study to Proposed %	Current to Proposed $	Current to Proposed %
Winter Rate Structure (November - March)									
Flat Rate	1.82	1.76	1.84	-0.07	-4%	0.09	5%	0.02	1%
Summer Rate Structure (April - October)									
Block 1	1.82	1.76	1.84	-0.06	-3%	0.08	5%	0.02	1%
Block 2	2.50	2.40	2.52	-0.10	-4%	0.12	5%	0.02	1%
Block 3	3.47	3.33	3.50	-0.14	-4%	0.17	5%	0.03	1%
Block 4	3.70	3.55	3.73	-0.15	-4%	0.18	5%	0.03	1%

Rate Structure (Same for City and County)

Block	Current	Study	Proposed
Flat Rate	All Usage	All Usage	All Usage
Block 1	1 - 10 ccf	1 - 10 ccf	1 - 10 ccf
Block 2	11 - 30 ccf	11 - 30 ccf	11 - 30 ccf
Block 3	31 - 70 ccf	31 - 60 ccf	31 - 60 ccf
Block 4	>71 ccf	>61 ccf	>61 ccf

Comparison of Monthly Usage Rate Options for City CII Customers

	2019	2019	2020	Changes					
Flat Rate or Block	Current Rate per ccf	Rate Study per ccf	Proposed Rate per ccf	Current to Rate Study		Rate Study to Proposed		Current to Proposed	
				$	%	$	%	$	%
Winter Rate Structure (November - March)									
Flat Rate	1.35	1.42	1.49	0.07	5%	0.07	5%	0.14	10%
Summer Rate Structure (April - October)									
Block 1	1.35	1.42	1.49	0.07	5%	0.07	5%	0.14	10%
Block 2	1.85	1.94	2.04	0.09	5%	0.10	5%	0.19	10%
Block 3	2.57	2.70	2.84	0.13	5%	0.14	5%	0.27	11%
Block 4	2.47	2.87	3.01	0.40	16%	0.14	5%	0.54	22%

Comparison of Monthly Usage Rate Options for County CII Customers

	2019	2019	2020	Changes					
Flat Rate or Block	Current Rate per ccf	Rate Study per ccf	Proposed Rate per ccf	Current to Rate Study		Rate Study to Proposed		Current to Proposed	
				$	%	$	%	$	%
Winter Rate Structure (November - March)									
Flat Rate	1.82	1.92	2.01	0.09	5%	0.09	5%	0.19	10%
Summer Rate Structure (April - October)									
Block 1	1.82	1.92	2.01	0.09	5%	0.09	5%	0.19	10%
Block 2	2.50	2.62	2.75	0.12	5%	0.14	5%	0.26	10%
Block 3	3.47	3.65	3.83	0.18	5%	0.19	5%	0.36	11%
Block 4	3.33	3.87	4.06	0.54	16%	0.19	5%	0.73	22%

Rate Structure (Same for City and County)

Block	Current	Study	Proposed
Flat Rate	All Usage	All Usage	All Usage
Block 1	0-AWC	0-AWC	0-AWC
Block 2	AWC-300%	AWC-300%	AWC-300%
Block 3	300%-700%	300%-600%	300%-600%
Block 4	>700%	>600%	>600%

*CII= Commercial, Industrial, and Institutional

*AWC = Average Winter Consumption. "AWC-300%" means usage greater than a customer's AWC and less than or equal to

Comparison of Water Monthly Usage Rate Options for City Irrigation Customers

Flat Rate or Block	2019 Current Rate per ccf	2019 Rate Study per ccf	2020 Proposed Rate per ccf	Changes: Current to Rate Study $	Current to Rate Study %	Rate Study to Proposed $	Rate Study to Proposed %	Current to Proposed $	Current to Proposed %
Winter Rate Structure (November - March)									
Flat Rate	1.85	1.71	1.80	-0.14	-8%	0.09	5%	-0.05	-3%
Summer Rate Structure (April - October)									
Block 1	1.85	1.71	1.80	-0.14	-8%	0.09	5%	-0.05	-3%
Block 2	2.57	2.38	2.50	-0.19	-7%	0.12	5%	-0.07	-3%
Block 3	2.74	2.53	2.66	-0.21	-8%	0.13	5%	-0.08	-3%

Comparison of Water Monthly Usage Rate Options for County Irrigation Customers

Flat Rate or Block	2019 Current Rate per ccf	2019 Rate Study per ccf	2020 Proposed Rate per ccf	Changes: Current to Rate Study $	Current to Rate Study %	Rate Study to Proposed $	Rate Study to Proposed %	Current to Proposed $	Current to Proposed %
Winter Rate Structure (November - March)									
Flat Rate	2.50	2.31	2.42	-0.19	-8%	0.12	5%	-0.07	-3%
Summer Rate Structure (April - October)									
Block 1	2.50	2.31	2.42	-0.19	-8%	0.12	5%	-0.07	-3%
Block 2	3.47	3.21	3.37	-0.26	-7%	0.16	5%	-0.10	-3%
Block 3	3.70	3.42	3.59	-0.28	-8%	0.17	5%	-0.11	-3%

Rate Structure (Same for City and County)

Block	Current	Study	Proposed
Flat Rate	All Usage	All Usage	All Usage
Block 1	1CCF-Target Budget	1CCF-Target Budget	1CCF-Target Budget
Block 2	Target Budget up to 300% of Target Budget	Target Budget up to 300% of Target Budget	Target Budget up to 300% of Target Budget
Block 3	Over 300% of Target Budget	Over 300% of Target Budget	Over 300% of Target Budget

* "Target budget" means the estimated amount of water consumed per acre, as established by the Public Utilities Director or his/her designee each year for customer based on factors including, but not limited to, evapotranspiration, and considering efficient water practices. A different target budget is established for each month of the irrigation season.

Proposed Water Rate Change Customer Impacts

Water Rate Change
Annual Impact on Select City Customers

Account Type	Annual Usage	Meter Size	2019 Current Rate	2020 Proposed Rate	$ Change	% Change
Residential Minimum Use	72 ccf	3/4	215.88	210.00	(5.88)	-2.72%
Residential Low Use	96 ccf	3/4	248.28	242.88	(5.40)	-2.17%
Residential Medium Use	255 ccf	3/4	559.17	556.95	(2.22)	-0.40%
Residential High Use	838 ccf	1	1,973.18	2,016.94	43.76	2.22%
Industrial Use	96,476 ccf	2	140,552.76	151,270.96	10,718.20	7.63%
Commercial Use	11,597 ccf	2	16,365.71	17,684.93	1,319.22	8.06%

Water Rate Change
Monthly Impact on Select City Customers

Account Type	Monthly Usage	Meter Size	2019 Current Rate	2020 Proposed Rate	$ Change	% Change
Residential Minimum Use	6 ccf	3/4	17.99	17.50	(0.49)	-2.72%
Residential Low Use	8 ccf	3/4	20.69	20.24	(0.45)	-2.17%
Residential Medium Use	21 ccf	3/4	46.60	46.41	(0.18)	-0.40%
Residential High Use	70 ccf	1	164.43	168.08	3.65	2.22%
Industrial Use	8,040 ccf	2	11,712.73	12,605.91	893.18	7.63%
Commercial Use	966 ccf	2	1,363.81	1,473.74	109.94	8.06%

Water Rate Change
Annual Impact on Select County Customers

Account Type	Annual Usage	Meter Size	2019 Current Rate	2020 Proposed Rate	$ Change	% Change
Residential Minimum Use	72 ccf	3/4	291.44	283.50	(7.94)	-2.72%
Residential Low Use	96 ccf	3/4	335.18	327.89	(7.29)	-2.17%
Residential Medium Use	255 ccf	3/4	754.88	751.88	(3.00)	-0.40%
Residential High Use	838 ccf	1	2,663.79	2,722.87	59.08	2.22%
Industrial Use	96,476 ccf	2	189,746.23	204,215.80	14,469.57	7.63%
Commercial Use	11,597 ccf	2	22,093.71	23,874.66	1,780.95	8.06%

Water Rate Change
Monthly Impact on Select County Customers

Account Type	Monthly Usage	Meter Size	2019 Current Rate	2020 Proposed Rate	$ Change	% Change
Residential Minimum Use	6 ccf	3/4	24.29	23.63	(0.66)	-2.72%
Residential Low Use	8 ccf	3/4	27.93	27.32	(0.61)	-2.17%
Residential Medium Use	21 ccf	3/4	62.91	62.66	(0.25)	-0.40%
Residential High Use	70 ccf	1	221.98	226.91	4.92	2.22%
Industrial Use	8,040 ccf	2	15,812.19	17,017.98	1,205.80	7.63%
Commercial Use	966 ccf	2	1,841.14	1,989.55	148.41	8.06%

Sewer Rate Change Comparisons

Comparison of Monthly Sewer Class Rate Changes

Flow $ Per CCF

	2019	2019	2020	Changes					
Class	Current Rate	Rate Study	Proposed Rate	Current to Rate Study		Rate Study to Proposed		Current to Proposed	
				$	%	$	%	$	%
1	1.86	1.94	2.29	0.08	4%	0.35	18%	0.43	23%
2	1.86	1.94	2.29	0.08	4%	0.35	18%	0.43	23%
3	1.86	1.94	2.29	0.08	4%	0.35	18%	0.43	23%
4	1.86	1.94	2.29	0.08	4%	0.35	18%	0.43	23%
5	1.86	1.94	2.29	0.08	4%	0.35	18%	0.43	23%
6	1.86	1.94	2.29	0.08	4%	0.35	18%	0.43	23%
7	Special Rate by Customer								

BOD $ Per CCF

	2019	2019	2020	Changes					
Class	Current Rate	Rate Study	Proposed Rate	Current to Rate Study		Rate Study to Proposed		Current to Proposed	
				$	%	$	%	$	%
1	0.78	0.68	0.80	-0.10	-13%	0.12	18%	0.02	3%
2	1.28	1.11	1.31	-0.17	-13%	0.20	18%	0.03	2%
3	2.10	1.83	2.16	-0.27	-13%	0.33	18%	0.06	3%
4	3.01	2.62	3.09	-0.39	-13%	0.47	18%	0.08	3%
5	3.80	3.29	3.88	-0.51	-13%	0.59	18%	0.08	2%
6	4.67	4.05	4.78	-0.62	-13%	0.73	18%	0.11	2%
7	Special Rate by Customer								

TSS $ Per CCF

	2019	2019	2020	Changes					
Class	Current Rate	Rate Study	Proposed Rate	Current to Rate Study		Rate Study to Proposed		Current to Proposed	
				$	%	$	%	$	%
1	0.40	0.49	0.58	0.09	4%	0.35	18%	0.18	45%
2	0.82	1.00	1.18	0.18	4%	0.35	18%	0.36	44%
3	1.39	1.70	2.01	0.31	4%	0.35	18%	0.62	44%
4	1.90	2.32	2.74	0.42	4%	0.35	18%	0.84	44%
5	2.46	3.01	3.55	0.55	4%	0.35	18%	1.09	44%
6	2.98	3.65	4.31	0.67	4%	0.35	18%	1.33	45%
7	Special Rate by Customer								

Total Sewer Rate Per CCF

	2019	2019	2020	Changes					
Class	Current Rate	Rate Study	Proposed Rate	Current to Rate Study		Rate Study to Proposed		Current to Proposed	
				$	%	$	%	$	%
1	3.04	3.11	3.67	0.07	-13%	0.12	18%	0.63	21%
2	3.96	4.05	4.78	0.09	-13%	0.20	18%	0.82	21%
3	5.35	5.47	6.45	0.12	-13%	0.33	18%	1.10	21%
4	6.77	6.88	8.12	0.11	-13%	0.47	18%	1.35	20%
5	8.12	8.24	9.72	0.12	-13%	0.59	18%	1.60	20%
6	9.51	9.64	11.38	0.13	-13%	0.73	18%	1.87	20%
7	Special Rate by Customer								

Class Structure

Block	BOD Strength mg/l	TSS Strength mg/l
1	0-300	0-300
2	300-600	300-600
3	600-900	600-900
4	900-1200	900-1200
5	1200-1500	1200-1500
6	1500-1800	1500-1800
7	>1800	>1800

Proposed Sewer Rate Change Customer Impacts

Sewer Rate Change
Annual Impact on Select City Customers

Account Type	Annualized Average Winter Water Usage (CCF)	2019 Current Rate	2020 Proposed Rate	$ Changes	% Change
Residential Minimum Use	24 ccf	145.92	88.08	(57.84)	-39.64%
Residential Low Use	48 ccf	145.92	176.16	30.24	20.72%
Residential Medium Use	96 ccf	291.84	352.32	60.48	20.72%
Residential High Use	180 ccf	547.20	660.60	113.40	20.72%
Industrial 2,4	24,168 ccf	121,806.72	137,999.28	16,192.56	13.29%
Commercial 2,1	408 ccf	1,444.32	1,530.00	85.68	5.93%

*Industrial & Commercial charges are calculated based on flow rate, BOD and TSS

Sewer Rate Change
Monthly Impact on Select City Customers

Account Type	Annualized Average Winter Water Usage (CCF)	2019 Current Rate	2020 Proposed Rate	$ Changes	% Change
Residential Minimum Use	2 ccf	12.16	7.34	(4.82)	-39.64%
Residential Low Use	4 ccf	12.16	14.68	2.52	20.72%
Residential Medium Use	8 ccf	24.32	29.36	5.04	20.72%
Residential High Use	15 ccf	45.60	55.05	9.45	20.72%
Industrial 2, 4	2,014 ccf	10,150.56	11,499.94	1,349.38	13.29%
Commercial 2,1	34 ccf	120.36	127.50	7.14	5.93%

*Industrial & Commercial charges are calculated based on flow rate, BOD and TSS

Stormwater Rate Change Comparisons

Comparison of Monthly Stormwater Rate Changes

		2019	2020	Changes Current to	
Account Type	**ERUs**	**Current Rate**	**Proposed Rate**	**$**	**%**
Single and Duplex <.25 Acre	All ERU	4.94	5.43	0.49	9.92%
Single and Duplex >.25 Acre	All ERU	6.91	7.60	0.69	9.99%
Triplex and Fourplex	All ERU	9.88	10.87	0.99	10.02%
All other Parcels	Per ERU	4.94	5.43	0.49	9.92%

*1 ERU = 1 residential property or 75 feet of street frontage for non-residential properties

Proposed Stormwater Rate Change Customer Impacts

Stormwater Rate Change
Annual Impact on Select City Customers

		2019	2020	Changes Current to Proposed	
Account Type	ERUs	Current Rate	Proposed Rate	$	%
Residential less than .25 Acre	Any ERU	59.28	65.16	5.88	9.92%
Residential more than .25 Acre	Any ERU	82.92	91.20	8.28	9.99%
Industrial*	300 ERU	1,482.00	1,629.00	147.00	9.92%
Commercial	120 ERU	592.80	651.60	58.80	9.92%

Stormwater Rate Change
Monthly Impact on Select City Customers

		2019	2020	Changes Current to Proposed	
Account Type	ERUs	Current Rate	Proposed Rate	$	%
Residential less than .25 Acre	Any ERU	4.94	5.43	0.49	9.92%
Residential more than .25 Acre	Any ERU	6.91	7.60	0.69	9.99%
Industrial	25 ERU	123.50	135.75	12.25	9.92%
Commercial	10 ERU	49.40	54.30	4.90	9.92%

APPENDIX E: Supplemental Information

Water Rates Compared with Recognizable Cities in Western States

Ranking	City or District Name	Average Monthly Charge
1	Flagstaff, AZ (1)	$ 121.40
2	Cheyenne, WY (2)	$ 68.60
3	Denver, CO (3)	$ 56.34
4	Reno, NV (4)	$ 51.14
5	Phoenix, AZ (5)	$ 44.67
6	Boise, ID (6)	$ 44.44
7	Las Vegas, NV (7)	$ 42.26
8	Salt Lake City, UT- 2019 Current	$ 37.44
	Salt Lake City, UT- 2020 Proposed	$ 37.17
9	Henderson, NV (8)	$ 26.47

* Cities compared with 7,480 gallons per month (10 CCF) and 24,000 gallons summer usage (32.09 CCF).
** Based on eight months Winter and four months Summer usage

Sewer Rates Compared with Nearby States

City or District Name	Average Monthly Charges	
Reno, NV	$	46.77
Boise, ID **	$	43.33
Phoenix, AZ **	$	37.02
Flagstaff, AZ	$	29.92
Cheyenne, WY **	$	29.32
Salt Lake City- 2020 Proposed	$	29.36
Denver, CO	$	26.99
Henderson, NV	$	25.78
Salt Lake City- 2019 Current	$	24.32
Las Vegas, NV	$	19.76

* Monthly Average Charges calculated based on 5,984 gallons per month (or 8 CCF)
** Includes Monthly base rate

Sewer Rates Compared with Local Cities November 2018

Ranking	City or District Name	Annual Charge
1	City of South Salt Lake	$ 502.66
2	Kearns Improvement District	$ 425.34
3	Magna City	$ 381.63
4	Ogden City	$ 364.56
	Salt Lake City- 2020 Proposed	$ 352.32
5	South Valley Sewer District	$ 332.56
6	Murray City **	$ 323.63
7	West Jordan City **	$ 323.09
8	Granger - Hunter Improvement District	$ 322.55
9	Midvalley Improvement District	$ 295.29
10	Salt Lake City- 2019 Current	$ 291.84
11	Taylorsville - Bennion Improvement District**	$ 265.95
12	Cottonwood Improvement District	$ 259.36
13	Sandy Suburban Improvement District	$ 257.04
14	Mt Olympus Improvement District	$ 234.69
15	South Davis Sewer District	$ 146.95

* Annual cost based on 12 months at 5,984 gallons per month (or 8 CCF per month) average winter consumption. Flat rate based on monthly rate multiplied by 12.

** Includes monthly base rate

Stormwater Rates Compared with Local Cities November 2018

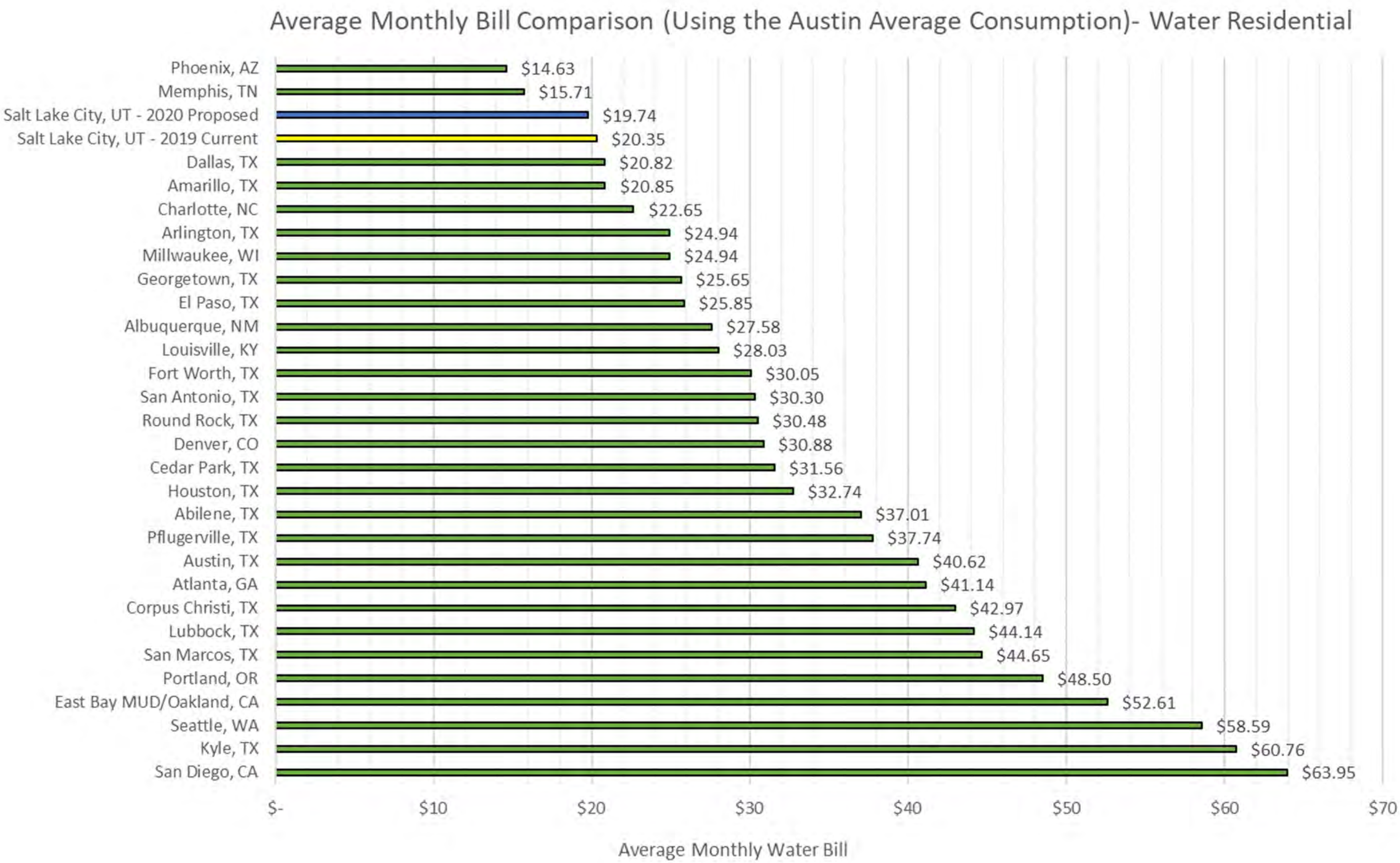
RANKING	CITY NAME	CURRENT RATE
1	PLEASANT GROVE	12.48
2	PROVO	9.20
3	DRAPER CITY	9.00
4	OGDEN CITY	7.85
5	SOUTH JORDAN CITY	7.15
6	BOUNTIFUL CITY	7.00
7	OREM	6.75
8	AMERICAN FORK	6.00
8	SANDY CITY	6.00
	SALT LAKE CITY (PROPOSED)	5.43
9	SALT LAKE CITY (Current)	4.94
10	MURRAY CITY	4.65
11	WEST JORDAN CITY	4.50
12	TAYLORSVILLE CITY	4.00

Public Utilities Department Local Area Water Rate Comparison
November 2018 (Highest to Lowest Ranking)

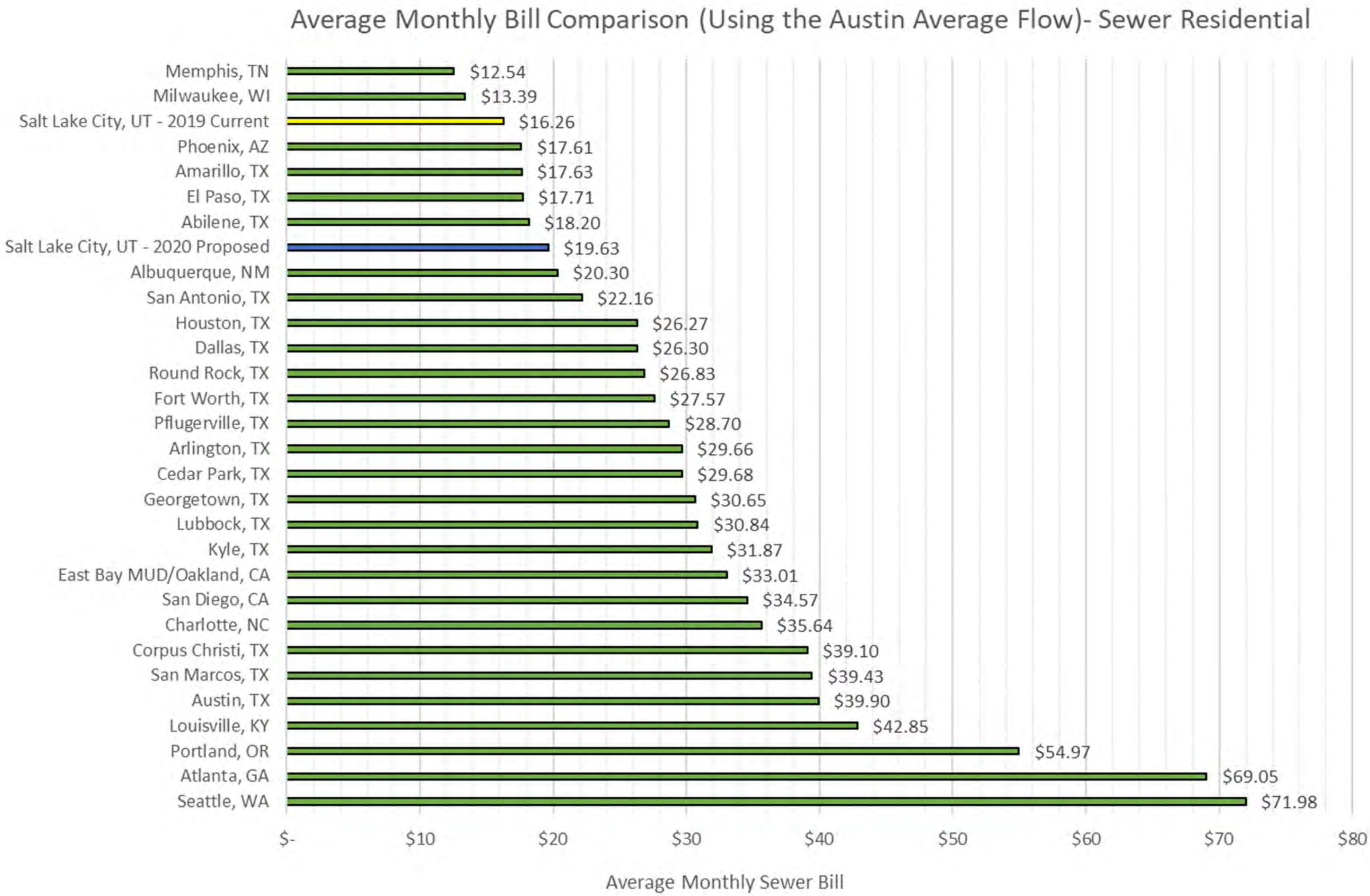
RANKING	CITY OR DISTRICT NAME	MONTHLY MINIMUM CHARGE	MINIMUM ALLOWANCE IN GALLONS	RATE OVER MINIMUM ALLOWANCE	PER GALLONS	MONTHLY FLOURIDE CHARGE	WINTER @ 7,480 GAL PER MONTH	SUMMER @ 23,936 GAL PER MONTH	TOTAL WINTER CHARGES*	TOTAL SUMMER CHARGES*	YEARLY TAX ON $200,000 PROPERTY	TOTAL CHARGES
1	PARK CITY - GRADUATED RATES (1)	49.08	0	6.12 - 10.31	1,000		104.01	269.91	832.07	1079.64		1911.71
2	AMERICAN FORK - GRADUATED RATES (2)	22.67	3,000	3.52 - 4.96	1,000		39.51	120.03	316.04	480.13		796.17
3	DRAPER CITY - GRADUATED RATES (3)	20.25	0	2.05 - 3.71	1,000		39.08	97.00	312.65	388.01		700.66
4	SOUTH JORDAN CITY - GRADUATED RATES (4)	30.00	0	2.00 - 2.50	1,000		45.33	84.09	362.64	336.36		699.00
5	RIVERTON CITY - GRADUATED RATES (5)	2.50	0	3.76 - 3.91	1,000		31.00	95.34	247.97	381.36		629.33
6	PLEASANT GROVE - GRADUATED RATES (6)	20.81	5,000	2.52 - 5.27	1,000		27.06	98.90	216.48	395.61		612.09
7	OGDEN CITY - GRADUATED RATES (7)	20.90	0	1.79 - 2.74	1,000		35.70	80.78	285.56	323.14		608.70
8	SALT LAKE CITY - OUTSIDE OF CITY	13.35	0	1.82 - 3.47	748		31.55	88.49	252.40	353.96		606.36
	SALT LAKE CITY - OUTSIDE OF CITY (Proposed)	12.53	0	1.84 -3.50	748		30.93	88.33	247.44	353.32		600.76
9	SANDY CITY - OUTSIDE OF CITY (8)	19.95	0	1.80 - 2.75	1,000		34.82	80.07	278.56	320.30		598.86
10	WEST JORDAN CITY (11)	26.58	0	1.65 - 2.18	1,000		39.04	71.41	312.34	285.64		597.98
11	KEARNS IMPROVEMENT DIST-GRADUATED RATES (9)	11.60	0	2.33 - 2.92	1,000		29.03	75.59	232.23	302.37	51.04	585.64
12	MAGNA - GRADUATED RATES (10)	17.41	6,000	1.89 - 2.12	1,000	0.98	21.19	53.65	169.50	214.62	178.81	562.92
13	SANDY CITY - INSIDE OF CITY (12)	14.43	0	1.64 - 2.53	1,000		28.01	69.65	224.12	278.59	35.75	538.46
14	SALT LAKE CITY - INSIDE OF CITY (13)	9.89	0	1.35 - 2.57	748		23.39	65.53	187.12	262.12	33.22	482.46
	SALT LAKE CITY - INSIDE OF CITY (Proposed)	9.28	0	1.37 - 2.59	748		22.98	65.56	183.84	262.24	35.75	481.83
15	BOUNTIFUL CITY - RESIDENTIAL HIGH ELEVATION	23.57	5,000	1.98	1,000		28.48	61.06	227.84	244.25		472.10
16	CITY OF SOUTH SALT LAKE	19.00	5,000	2.25	1,000	2.00	26.58	63.61	212.64	254.42		467.06
17	GRANGER - HUNTER IMPROVEMENT DISTRICT (14)	13.00	0	1.61 -1.86	1,000		25.10	54.73	200.80	218.92	28.55	448.27
18	BOUNTIFUL CITY - RESIDENTIAL LOW ELEVATION	21.39	5,000	1.79	1,000		25.83	55.29	206.63	221.14		427.78
19	JVWCD	3.00	0	1.87 - 2.34	1,000		16.99	59.01	135.90	236.04	44.00	415.94
20	PROVO	15.29	0	0.87 - 1.44	1,000		21.80	49.76	174.38	199.03		373.41
21	TAYLORSVILLE/BENNION IMPROVEMENT DISTRICT (15	7.00	0	1.43 - 1.87	1,000		18.35	49.12	146.78	196.48	6.88	350.14
22	MURRAY CITY - GRADUATED RATES (16)	10.00	0	0.95 - 1.40	748		19.90	46.95	159.20	187.80		347.00
23	OREM - GRADUATED RATES (17)	17.16	0	0.79 - 0.99	1,000		23.07	38.66	184.55	154.63		339.18

CALCULATION OF COMPARISONS

** BASED ON EIGHT MONTHS WINTER AND FOUR MONTHS SUMMER*
(1) RATES ARE $6.12/THOUSAND FOR 0-5,000 GALLONS, $9.81/THOUSAND FOR 5,001-15,000 GALLONS, & $10.31/THOUSAND FOR 15,001-25,000 GALLONS
(2) RATES ARE $22.67 FOR 0-3,000 GALLONS, $3.52/THOUSAND FOR 3,001-6,000 GALLONS, $4.24/THOUSAND FOR 6,000-9,000 GAL & $4.96/THOUSAND OVER 9,000 GALLONS
(3) RATES ARE $2.05/THOUSAND FOR 0-5,000 GALLONS, $3.46/THOUSAND FOR 5,001-20,000 GALLONS, & $3.71/THOUSAND FOR 20,001-50,000 GALLONS
(4) RATES ARE $2.00/THOUSAND FOR 0-6,000 GALLONS, $2.25/THOUSAND FOR 6,001-17,000 GALLLONS & $2.50/THOUSAND FOR 17,001 - 42,000 GALLONS
(5) RATES ARE $3.76 FOR 0-5,000 GALLONS & $3.91/THOUSAND OVER 5,000 GALLONS
(6) RATES ARE $20.81 FOR 0-5,000 GALLONS, $2.52/THOUSAND FOR 5,001-10,000 GALLONS, $3.68/THOUSAND FOR 10,001-15,000 GALLONS & $5.27/THOUSAND OVER 15,000 GALLONS
(7) RATES ARE $1.79/THOUSAND FOR 0-6,000 GALLONS & $2.74/THOUSAND FOR 6,001-42,000 GALLONS
(8) RATES ARE $1.80/THOUSAND FOR 0-6,000 GALLONS & $2.75/THOUSAND FOR 6,001-40,000 GALLONS
(9) RATES ARE $2.33/THOUSAND FOR 0-10,000 GALLONS & $2.92/THOUSAND FOR 10,001-25,000 GALLONS
(10) RATES ARE $1.64/THOUSAND FOR 0-6,000 GALLONS & $2.53/THOUSAND FOR 6,001-40,000 GALLONS
(11) RATES ARE $17.41 FOR 0-6,000 GALLONS, $1.89/THOUSAND FOR 6,001-18,000 GALLONS, & $2.12/THOUSAND FOR 18,001-35,000 GALLONS
(12) RATES ARE $1.65 FOR 0-7,000 GALLONS, $1.90/THOUSAND FOR 7,001-20,000 GALLONS, & $2.18/THOUSAND FOR OVER 20,000 GALLONS
(13) INCLUDES METROPOLITAN WATER PROPERTY TAX
(14) RATES ARE $1.61/THOUSAND FOR 0-7,000 GALLONS, $1.73/THOUSAND FOR 7,001-15,000 GALLONS & $1.86/THOUSAND FOR OVER 15,000 GALLONS
(15) RATES ARE $1.43/THOUSAND FOR 0-6,000 GALLONS & $1.87/THOUSAND FOR 6,001-25,000 GALLONS
(16) RATES ARE $.95/HUNDRED FOR 0-8 HCF, $1.15/HUNDRED FOR 9-25 HCF & $1.40/HUNDRED FOR 26-49 HCF
(17) RATES ARE $.79/THOUSAND FOR 0-11,000 GALLONS, $.99/THOUSAND FOR 11,001-34,000 GALLONS

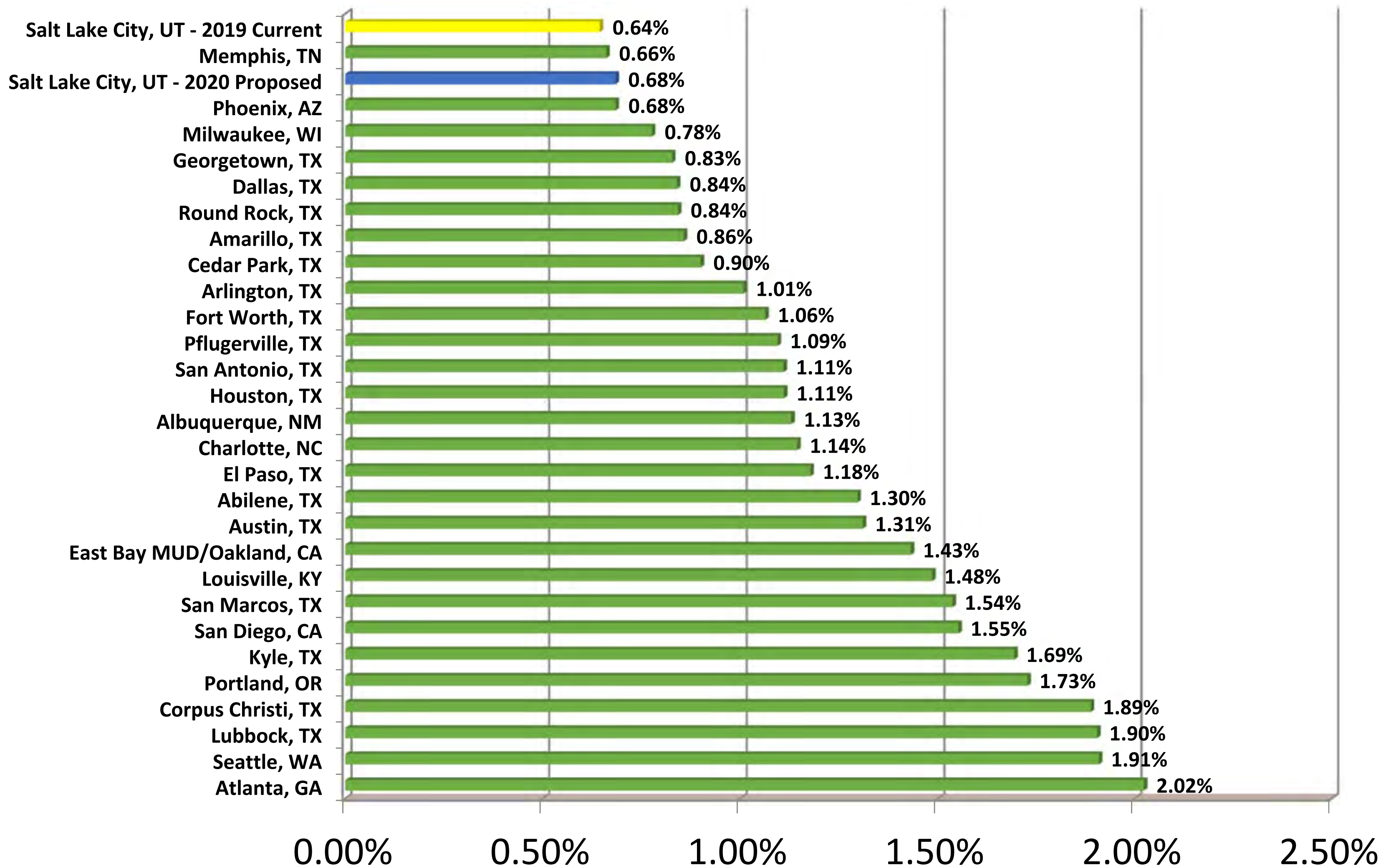


*Cities Other than SLC- Data Source Rates from March 2018 Austin National Survey
** Rates Calculated of an average of 5,800 gallons a month or 7.54 CCF



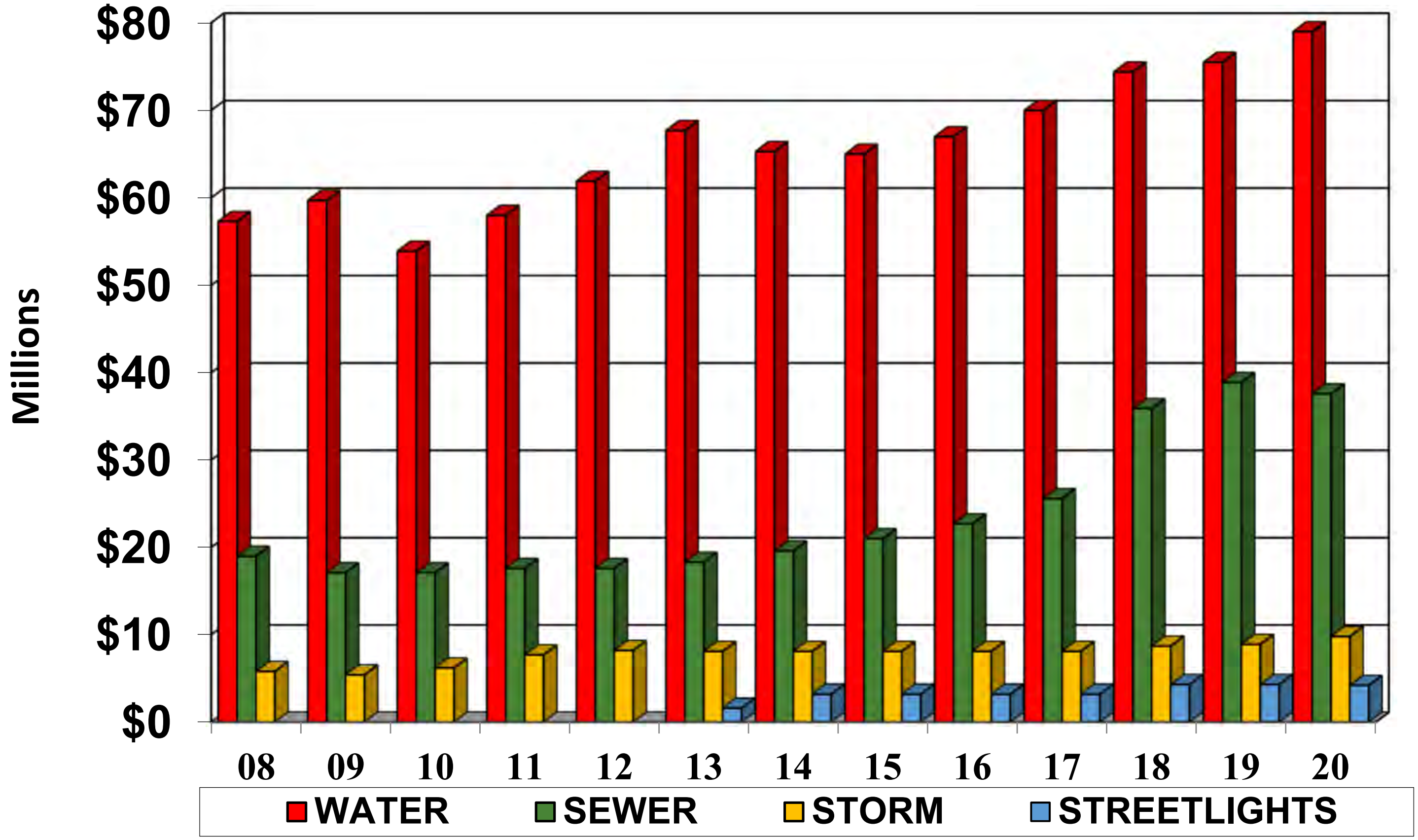
*Cities Other than SLC- Data Source Rates from March 2018 Austin National Survey
** Rates Calculated of an average of 4,000 gallons a month or 5.35 CCF

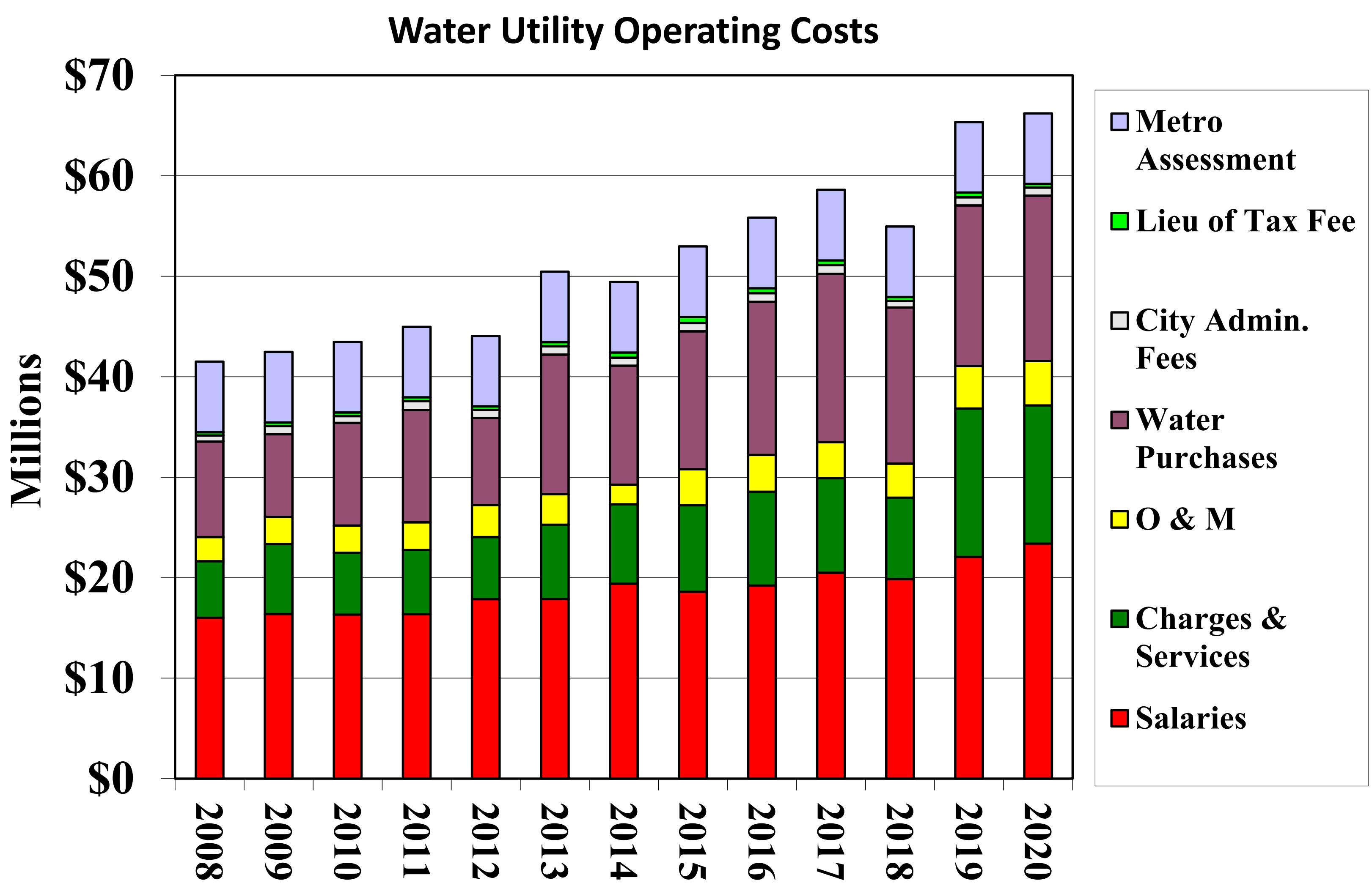
Residential Water & Sewer Bill as a Percent of Median Household Income (Using Austin Average Consumption & Flows as of March 2018 Report)

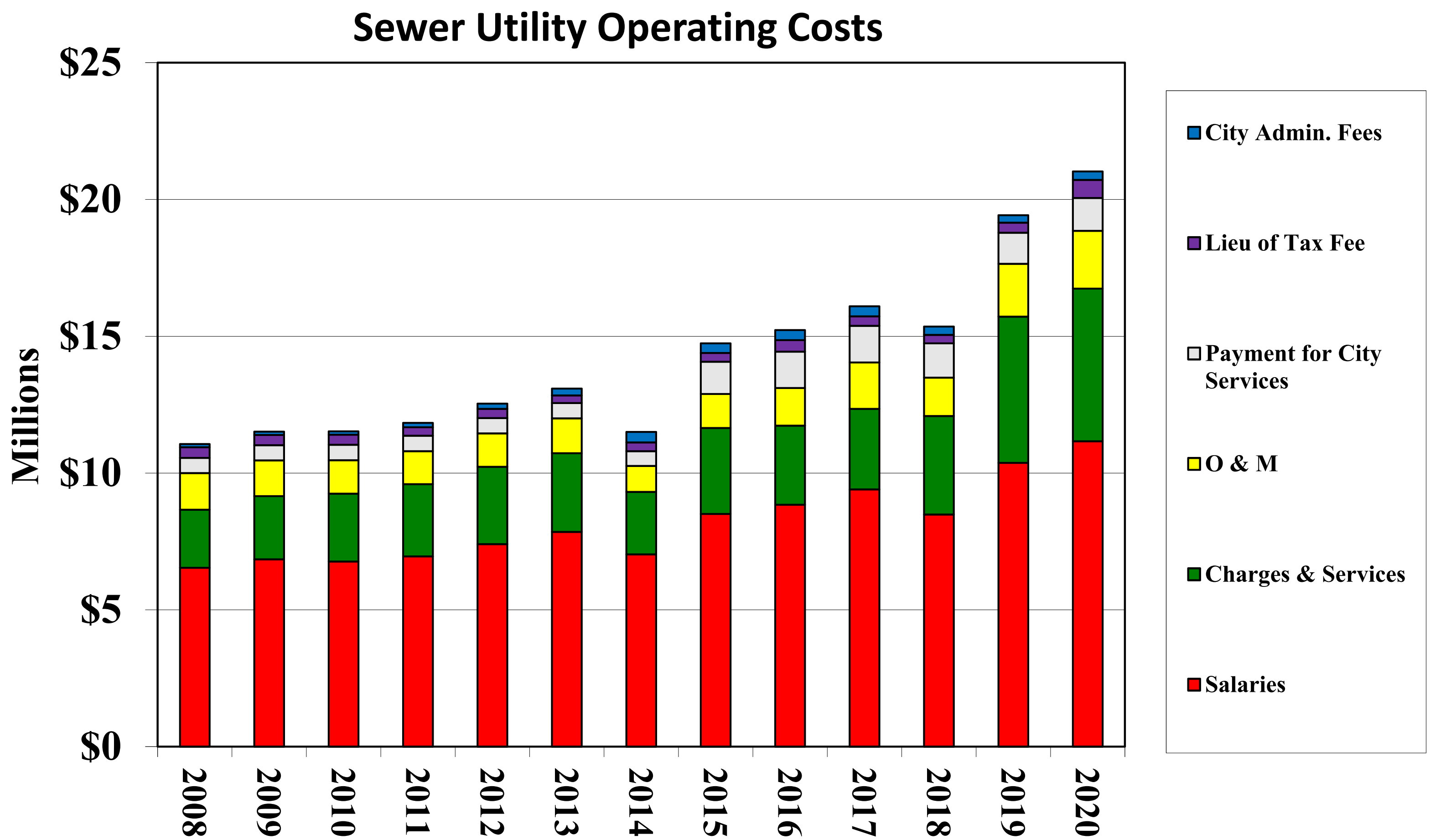


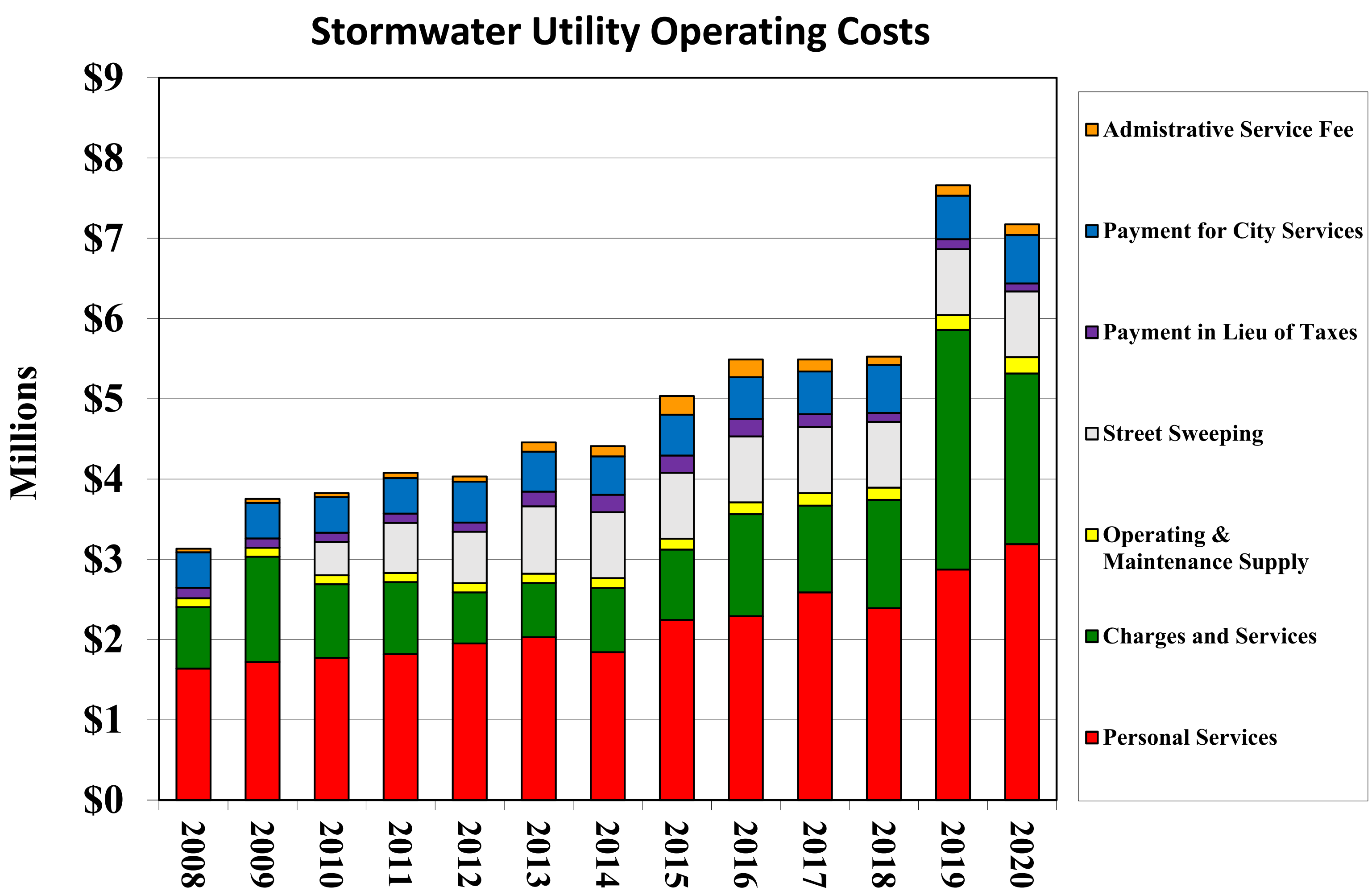
* The percentage of median household income was calculated by taking the results of each individual city's bill based on that city's rates and the usage of the Austin average consumption and flows. From those results, we divide the annual amount by the individual city's 10 year average median income.
** Median Income source: www.deptofnumbers.com/income/us/l

Public Utilities Operating Revenue

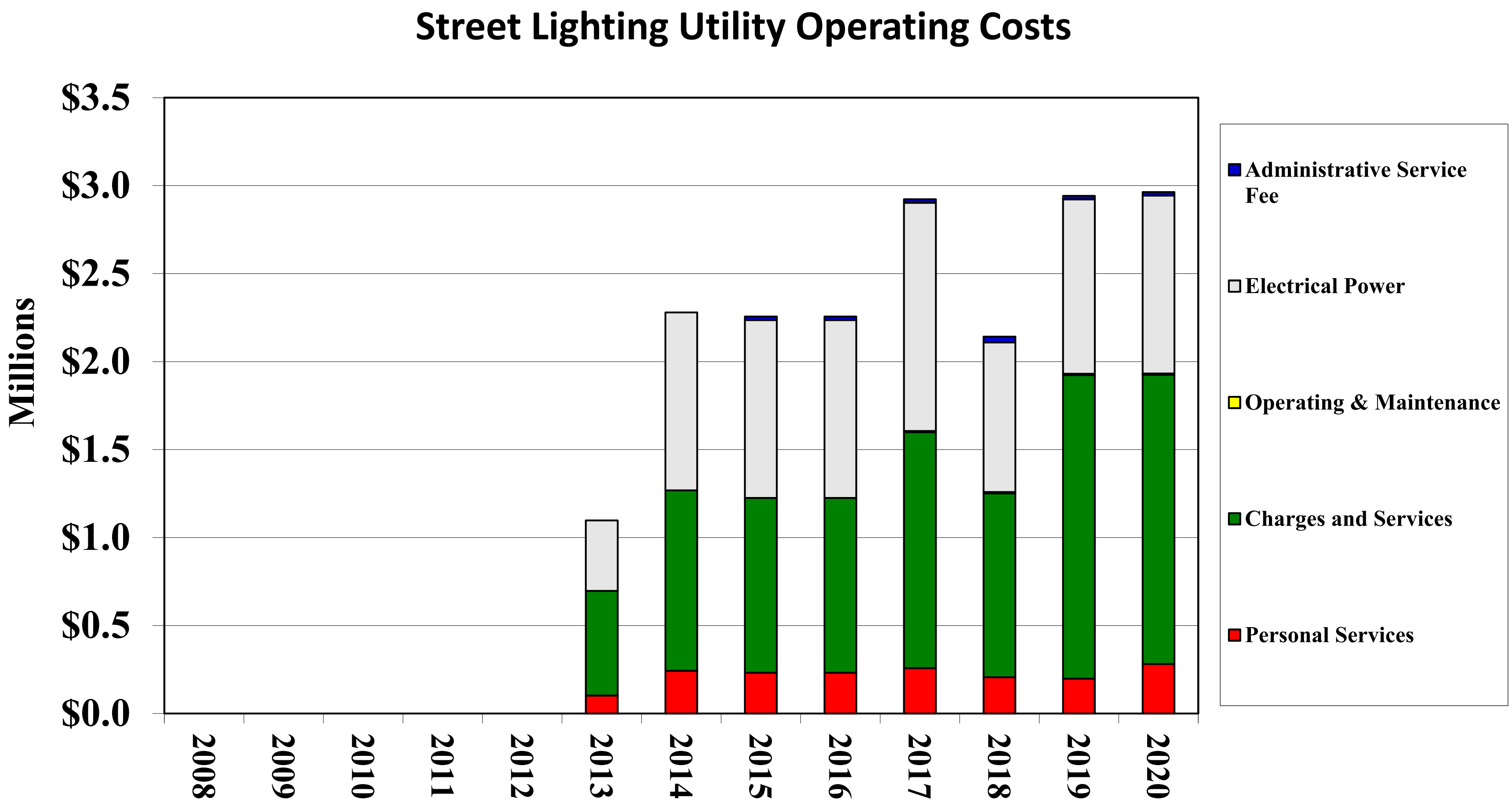



Water Utility Operating Costs
$70
$60
$50
$40
$30
$20
$10
$0
Millions
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
Metro Assessment
Lieu of Tax Fee
City Admin. Fees
Water Purchases
O & M
Charges & Services
Salaries

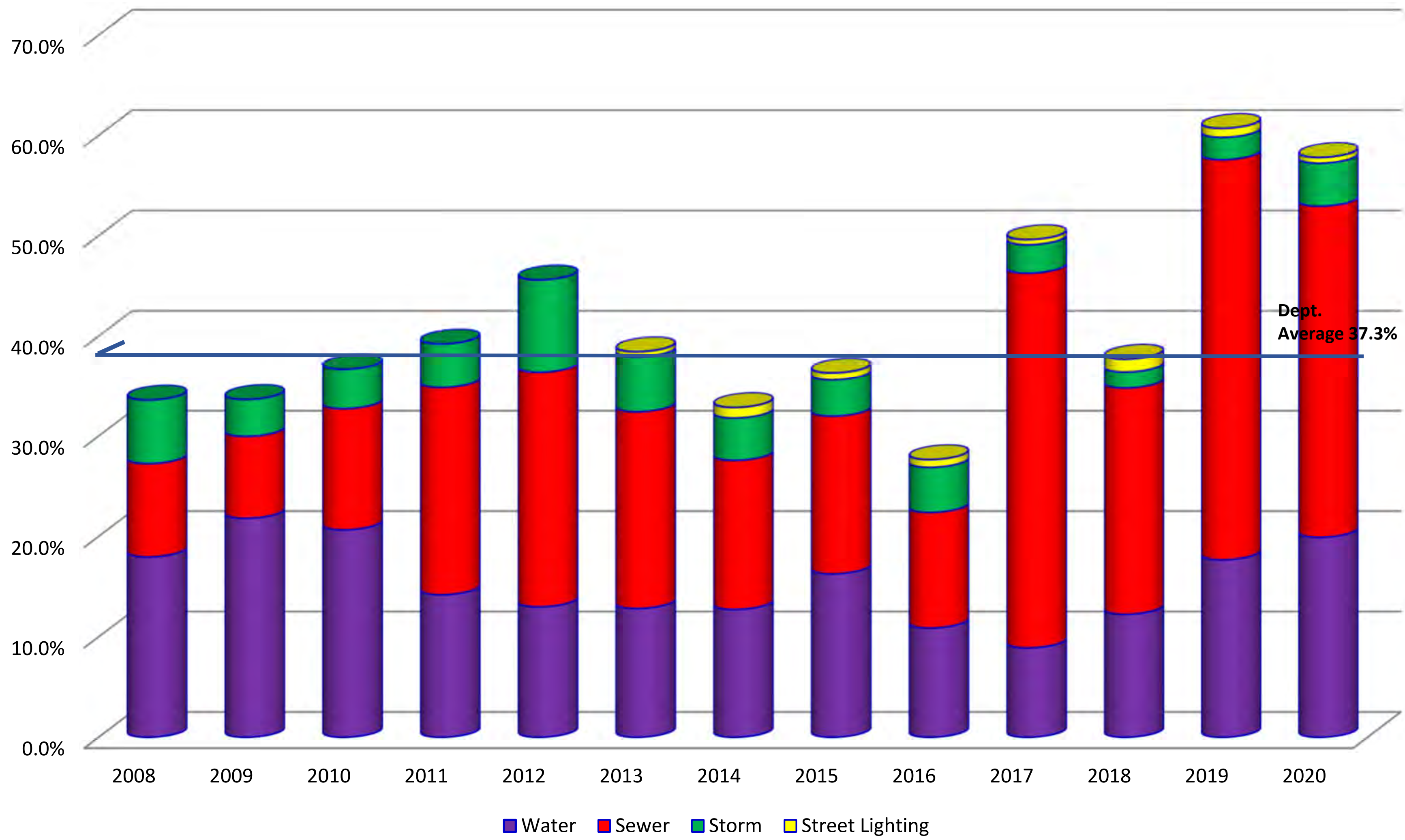

Sewer Utility Operating Costs
$25
$20
$15
$10
$5
$0
Millions
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
City Admin. Fees
Lieu of Tax Fee
Payment for City Services
O & M
Charges & Services
Salaries



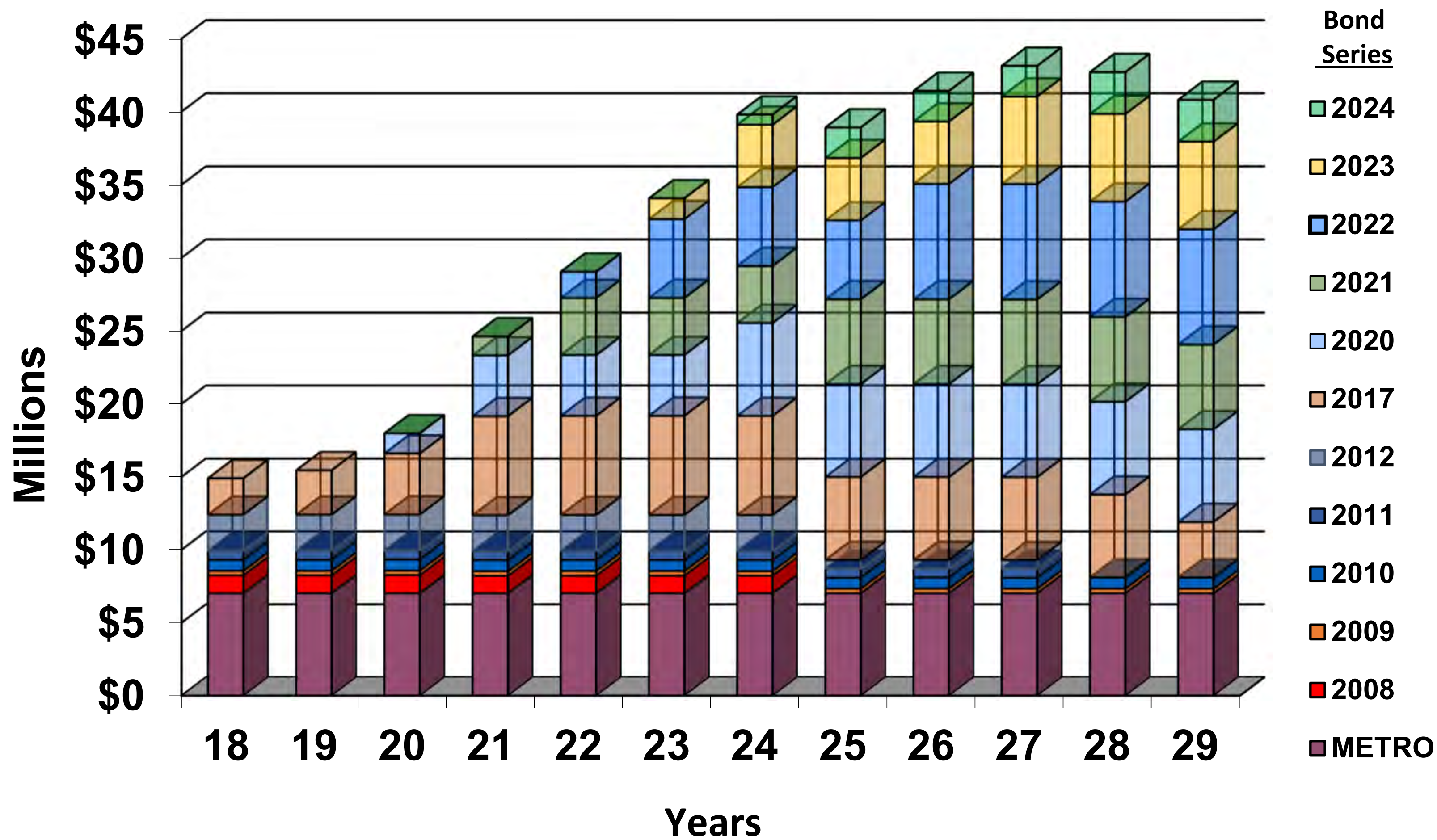
Stormwater Utility Operating Costs
$9
$8
$7
$6
$5
$4
$3
$2
$1
$0
Millions
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
Admistrative Service Fee
Payment for City Services
Payment in Lieu of Taxes
Street Sweeping
Operating & Maintenance Supply
Charges and Services
Personal Services

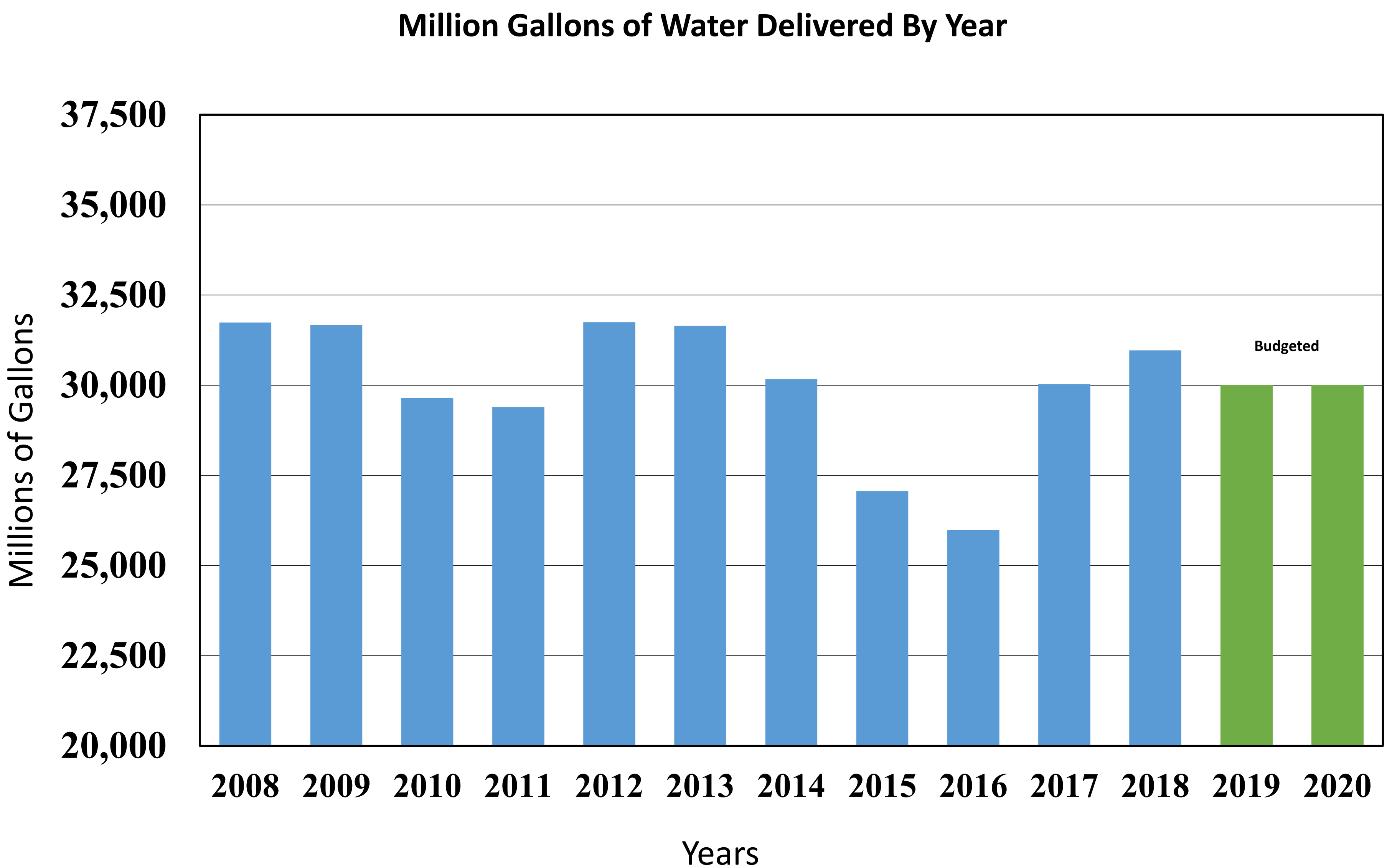

Street Lighting Utility Operating Costs
$3.5
$3.0
$2.5
$2.0
$1.5
$1.0
$0.5
$0.0
Millions
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
Administrative Service Fee
Electrical Power
Operating & Maintenance
Charges and Services
Personal Services

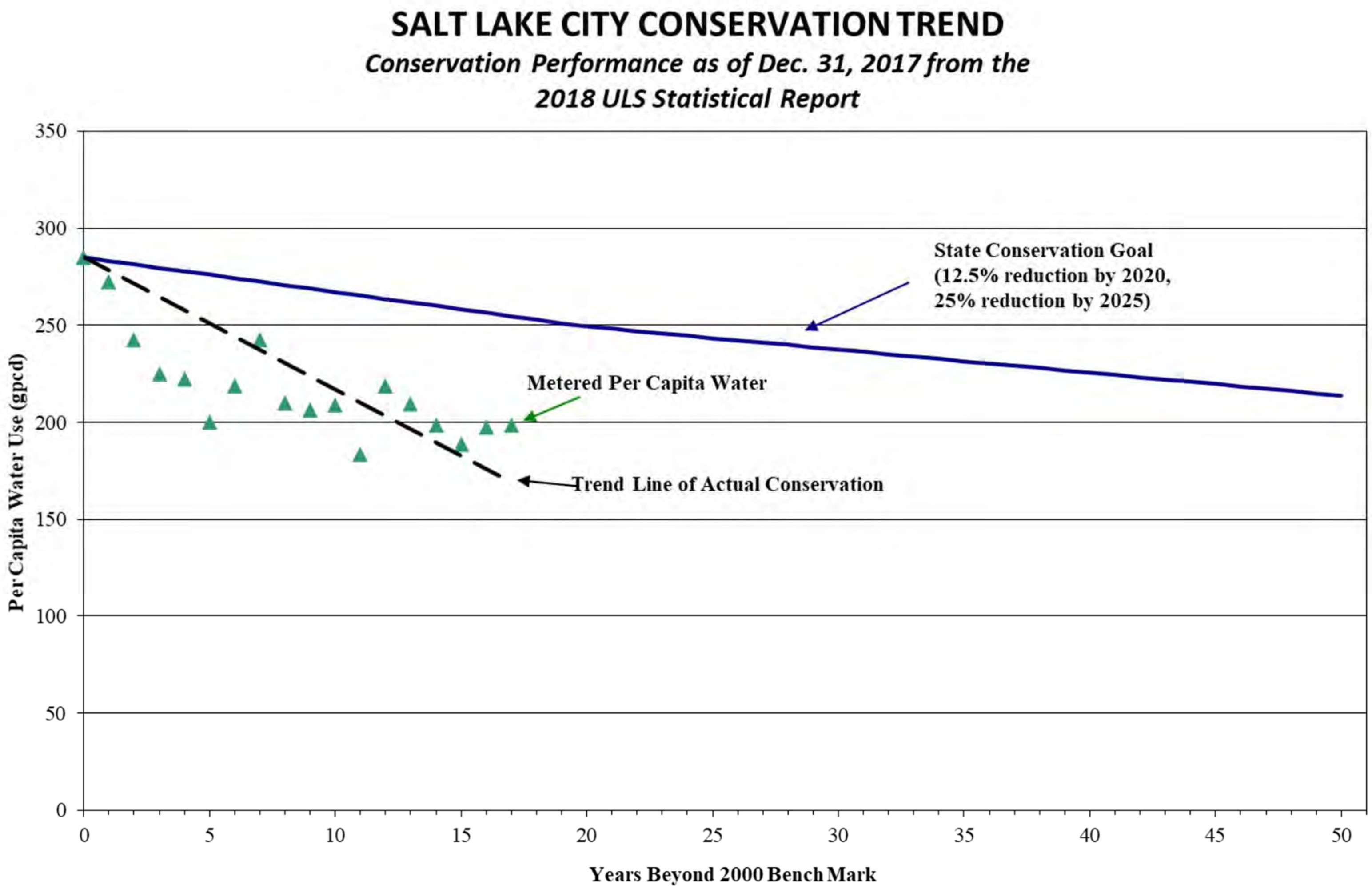
Public Utilities CIP Budget as a Percent of Department Requested Budget



Public Utilities Proposed Debt Service Schedule and Metropolitan Water Assessment



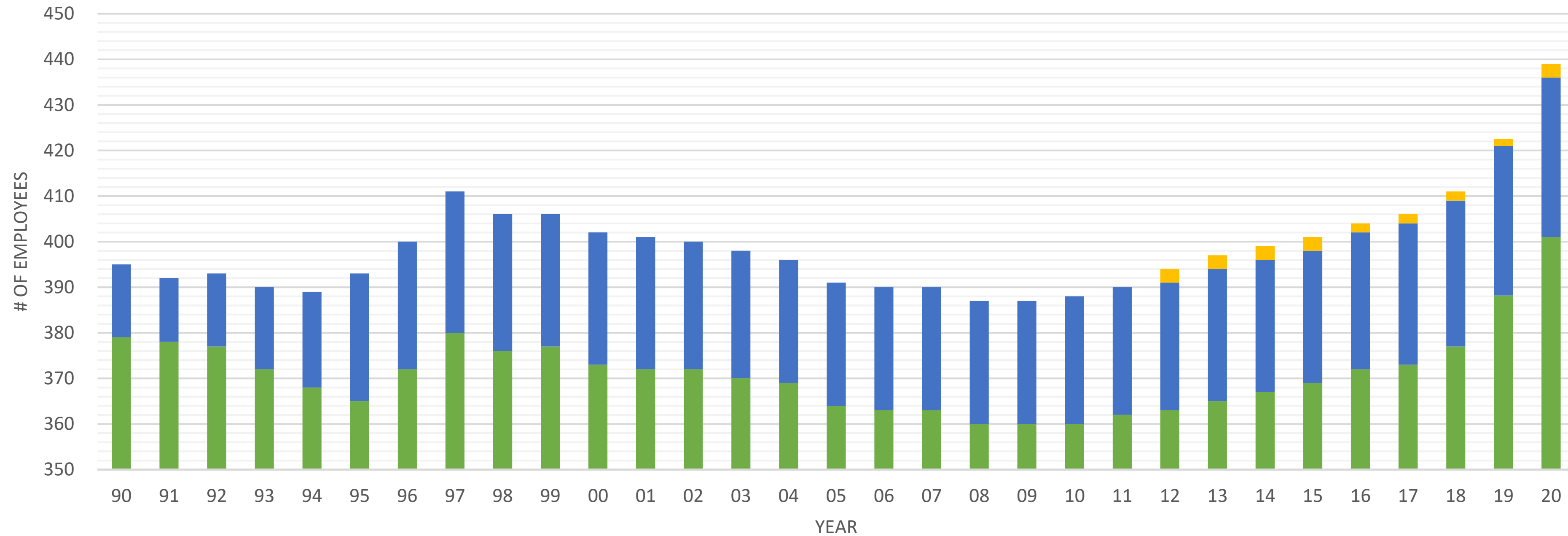

Million Gallons of Water Delivered By Year
Millions of Gallons
37,500
35,000
32,500
30,000
27,500
25,000
22,500
20,000
Budgeted
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
Years


SALT LAKE CITY CONSERVATION TREND
Conservation Performance as of Dec. 31, 2017 from the
2018 ULS Statistical Report
350
300
250
200
150
100
50
0
Per Capita Water Use (gpcd)
State Conservation Goal
(12.5% reduction by 2020,
25% reduction by 2025)
Metered Per Capita Water
Trend Line of Actual Conservation
0
5
10
15
20
25
30
35
40
45
50
Years Beyond 2000 Bench Mark

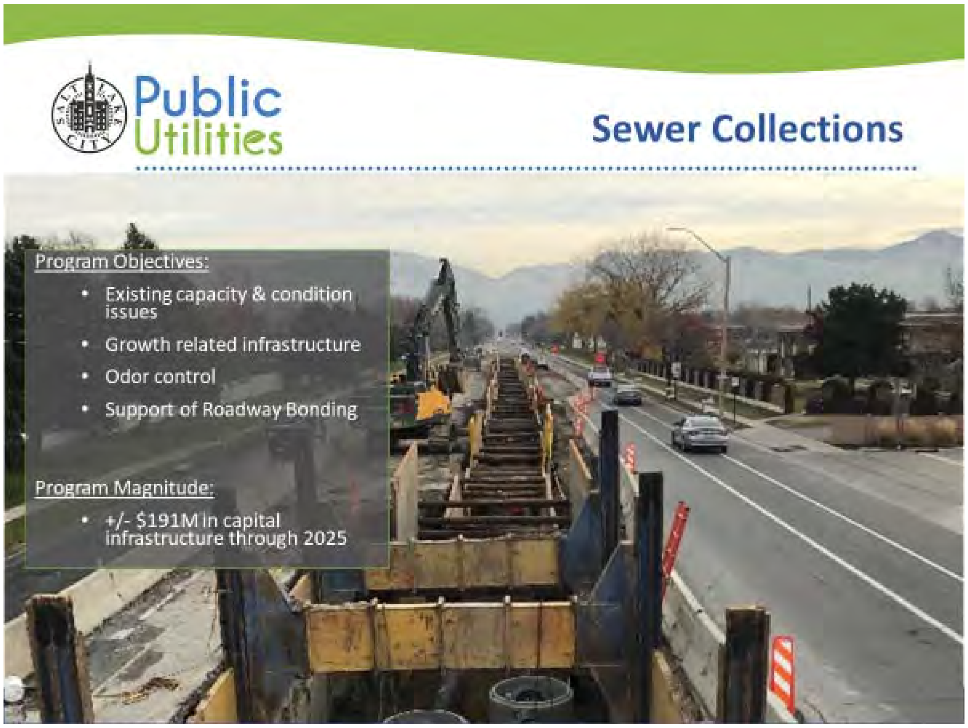
Proposed Personnel Adjustments FY 2019/2020

	TOTAL	WATER	SEWER	STORM WATER	STREET LIGHTING
Prior FY Ending FTE Balances by Fund	422.50	272.77	115.43	32.80	1.50
NEW POSITIONS REQUESTED FOR FY 19/20					
1) RECORDS TECHNICIAN	1.00	0.80	0.10	0.10	
2) COMMUNITY & ENGAGEMENT COORD	1.00	0.50	0.40	0.10	
3) SUSTAINABILITY PROGRAM MANAGER	1.00	1.00			
4) GIS LEAK DETECTOR SYSTEM TECH II UNON	1.00	0.50	0.30	0.20	
5) OFFICE TECHNICIAN II	1.00		1.00		
6) PRETREATMENT INSPECTOR/PERMIT WRITER	1.00		1.00		
7) PRETREATMENT SENIOR SAMPLER/INSPECTOR	1.00		1.00		
8) FOG/SEWER RATE PROGRAM SUPERVISOR	1.00		1.00		
9) MAINTENANCE ELECTRICIAN IV	1.00	1.00			
10) ENGINEERING TECH I	1.00				1.00
11) ENGINEERING TECH II	2.00	1.00	0.50	0.50	
12) ENGINEERING TECH III	1.00	0.50	0.25	0.25	
13) ENGINEER II	1.00	0.50	0.25	0.25	
14) ENGINEER III	2.00	1.00	0.50	0.50	
Total Increase of 16 FTE's for Public Utilities Dept.	438.50	279.57	121.73	34.70	2.50
Two Seasonal Watershed Workers	1.00	1.00			
TOTAL FTE'S	439.50	280.57	121.73	34.70	2.50
CHANGES TO FTE DUE TO REORGANIZATION:		1.65	-1.10	-0.55	0.00
Agency Totals for FY 2019/2020	439.50	282.22	120.63	34.15	2.50

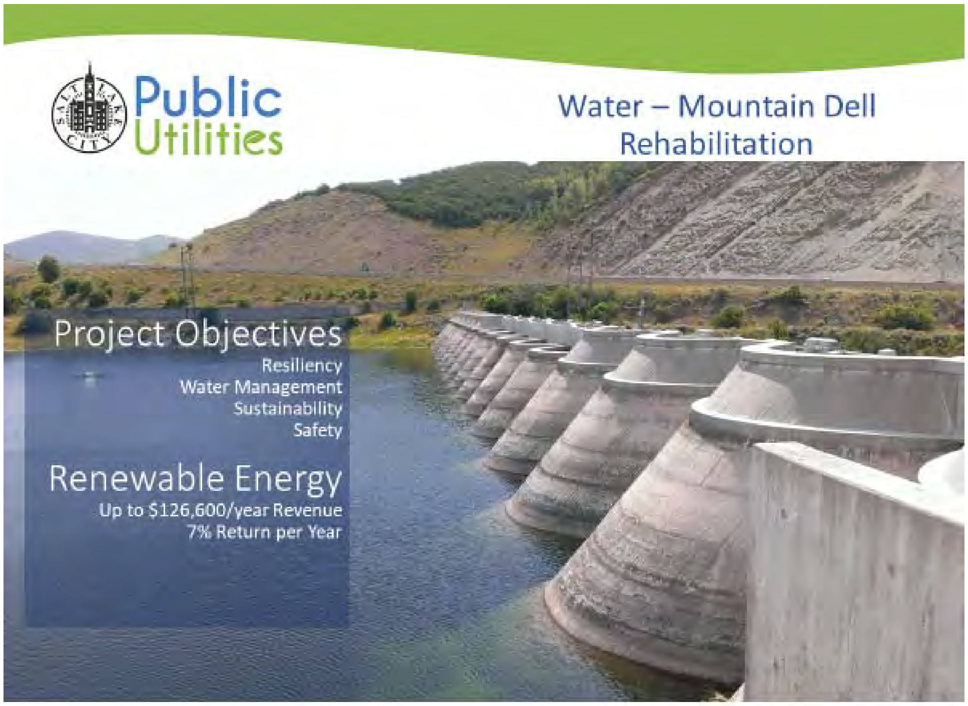
Public Utilities Number of Employees By Fund By Fiscal Year

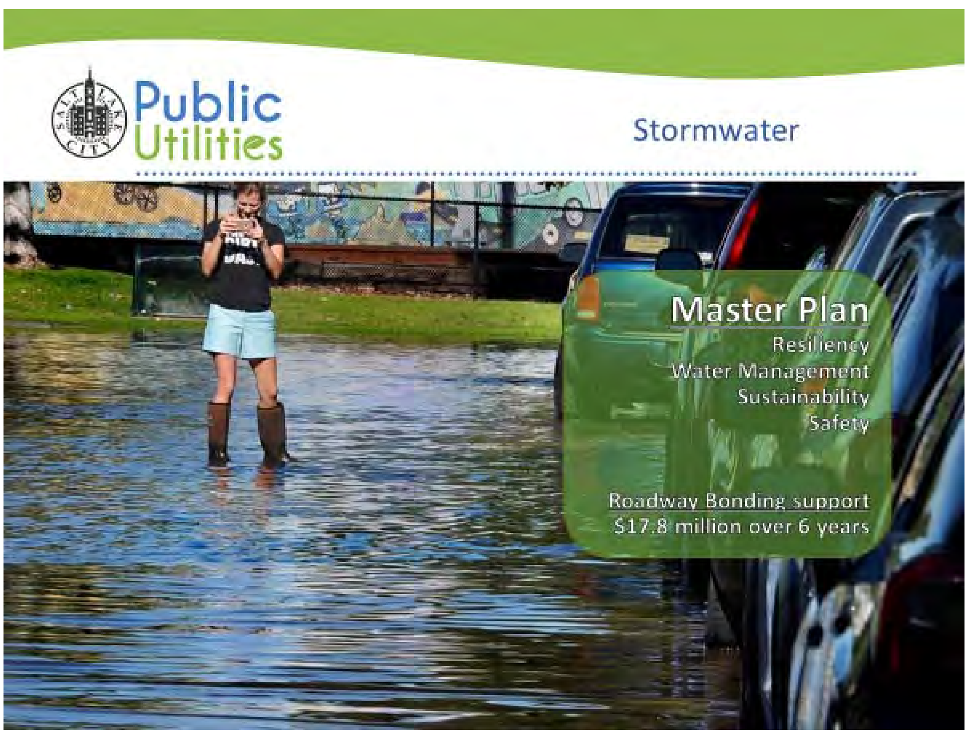


Year	90	91	92	93	94	95	96	97	98	99	00	01	02	03	04	05	06	07	08	09	10	11	12	13	14	15	16	17	18	19	20
Water & Sewer	379	378	377	372	368	365	372	380	376	377	373	372	372	370	369	364	363	363	360	360	360	362	363	365	367	369	372	373	377	388	401
Storm Water	16	14	16	18	21	28	28	31	30	29	29	29	28	28	27	27	27	27	27	27	28	28	28	29	29	29	30	31	32	33	35
Street Lighting																							3	3	3	3	2	2	2	2	3
# of Water Connections	84,098	84,526	85,921	86,360	86,665	87,233	85,514	89,191	90,393	89,776	80,218	90,766	91,283	81,751	92,955	92,344	90,748	90,912	90,920	90,976	90,958	90,624	90,251	90,349	90,435	90,451	91,467	91,545	91,802	???	???


Public Utilities
Sewer Collections
Program Objectives:
• Existing capacity & condition issues
• Growth related infrastructure
• Odor control
• Support of Roadway Bonding
Program Magnitude:
• +/- $191M in capital infrastructure through 2025


Public Utilities
Water – Capital Program
• East West Aqueduct Phase I ($10.0 million)
• Treatment Plant rehabilitation ($8.0 million)
• Road way bond support $9.65 million FY 20 (~$27.54 million over 6 years)
• Total Water Main Replacements ($23 million)


Public
Utilities
Water – Mountain Dell
Rehabilitation
Project Objectives
Resiliency
Water Management
Sustainability
Safety
Renewable Energy
Up to $126,600/year Revenue
7% Return per Year


Public
Utilities
Stormwater
Master Plan
Resiliency
Water Management
Sustainability
Safety
Roadway Bonding support
$17.8 million over 6 years

JACQUELINE M. BISKUPSKI
Mayor

DEPARTMENT OF
PUBLIC UTILITIES

CITY COUNCIL TRANSMITTAL

Patrick Leary, Chief of Staff

Date Received: 4/4/2019
Date sent to Council: 4/9/2019

TO: Salt Lake City Council
Charlie Luke, Chair

DATE: April 4, 2019

FROM: Laura Briefer, MPA
Director, Department of Public Utilities

SUBJECT: Request for a City Council resolution supporting the pursuit of the Water Reclamation Facility reconstruction as required to comply with Utah Administrative Code R317-1-3-3 and Utah Department of Environmental Quality Permit Requirements

STAFF CONTACTS: Jesse Stewart, Deputy Director, jesse.stewart@slcgov.com; Jason Brown, PE, Chief Engineer, jason.brown@slcgov.com; Lisa Tarufelli, Finance Administrator, lisa.tarufelli@slcgov.com

Laura Briefer, Jesse Stewart, Jason Brown, and Lisa Tarufelli will address the Council on this resolution.

DOCUMENT TYPE: Resolution (Exhibit A)

RECOMMENDATION: Approve a resolution supporting the pursuit of the reconstruction of the Water Reclamation Facility, particularly the implementation of biological phosphorus removal technology to meet requirements of Utah Administrative Code R317-1-3-3. It is also required that the adopted resolution include an approximate budget for the construction of the selected technology for conformance with the approved variance requirements.

BUDGET IMPACT:
The reconstruction of the Water Reclamation Facility (WRF) has been in the Public Utilities' long term plan and the projected costs have been projected in the Department's longer term budget planning since at least in 2015. At this time, the total estimated costs for design and construction of the new WRF is $528,130,000 (Exhibit B). The Department has worked with the Administration, Council, and the Public Utility Advisory Committee over the last several years to develop a long term financing and rate strategy. Public Utilities' goal of the financing strategy is to minimize the impact to the community, and balancing the financing, infrastructure, and regulatory requirements of the new WRF.

The costs for the WRF will be covered with a combination of rate increases, revenue bonds, and possibly longer term loans through state and federal programs. As such, Public Utilities is providing two

representative financing scenarios for the project, one using traditional revenue bonds, and the other using a federal loan for 49% of the project using under the federal Water Infrastructure Finance and Innovation Act (WIFIA). The scenarios, presented in **Exhibit C**, are presented in the context of the Sewer Utility's overall long term budget and cash flow planning in order to provide context to the budgetary requirement of the resolution.

Public Utilities plans to apply for a WIFIA loan for this project and believes this project would be competitive in the loan process (see WIFIA fact sheet, **Exhibit D**). We are also investigating state loans. Securing a loan under the federal WIFIA or state water infrastructure lending programs would mitigate some of the near-term impacts to ratepayers. In addition, the WIFIA loan program provides for a longer term (35 year) payback, which would distribute costs of the project more fairly across the generations that will benefit from the new WRF. The WIFIA and state loans require Buy America and federal wages, which may increase the cost of the project. Any additional costs can also be mitigated by the interest rates and longer payback terms.

Success in a WIFIA or state loan process is not guaranteed, in which case revenue bonding would be required. Therefore, Public Utilities is providing budgetary information for revenue bonding and federal/state loan programs.

BACKGROUND/DISCUSSION:

The Utah Department of Environmental Quality (UDEQ) adopted a new rule that went into effect on January 1, 2016 (R317-3-3), limiting the amount of phosphorus permitted to be discharged by wastewater treatment plants into State water bodies. Public Utilities was fully engaged with the rule making process and provided numerous comments and concerns outlining the impact to Salt Lake City and sewer rate payers. The new rule specifies compliance by January 1, 2020; however, the rule also allows for the Director of the UDEQ Water Quality Division to permit a variance to the compliance date if due diligence is made towards meeting the requirements of the rule.

Due to numerous issues associated with meeting the January 1, 2020 compliance date, including the age of the existing WRF, construction schedule, and procurement of funding, Public Utilities requested a variance on March 26, 2018. Conditional approval from UDEQ was received on May 29, 2018 to extend the compliance date to January 1st 2025. One of the conditions of the variance states that the Public Utilities Department must submit, no later than July 1, 2019 "*A City Council resolution supporting the pursuit of the facility upgrade to the selected biological phosphorus removal technology. The resolution shall include the approximate budget for the facility upgrade.*" **Exhibit E** provides all relevant regulatory correspondence to date.

It should be noted that over the last several years, Public Utilities evaluated numerous alternatives of meeting the new phosphorus rule that included alternatives to retrofit the existing WRF. Due to the age and condition of the existing WRF, it was determined that retrofitting the 55-year old WRF was not physically or economically feasible. It was also determined that the existing WRF has met its useful life, and needs to be reconstructed. For example, the existing WRF does not meet current seismic standards, and is vulnerable to disruption during extreme flood events. Engineering reports documenting these analyses are available to review upon request. Public Utilities can also present a summary of these studies if needed.

Public Utilities is currently designing the new WRF. The design and construction costs have been planned within Public Utilities' budgets starting in fiscal year 2018, and through 2025. This includes bond revenue

and design costs in the proposed FY 2020 budget. Currently, the estimated cost for construction of the new WRF is $528,130,000. This cost may change as engineering designs are completed, and are subject to evolving regional construction costs.

The construction is phased over seven years with the objective of meeting the rule by 2024, one year ahead of the regulatory compliance requirement. The 2024 objective is to allow for full commissioning of the new WRF to ensure the plant and all of its operational components will be in compliance by the 2025 deadline.

PUBLIC PROCESS: Public Utilities has engaged the public regarding the need for the new WRF throughout the last few years. Public Utilities has engaged the public regarding rate increases associated with financing the WRF. Examples of public engagement include community council meetings, periodic updates during City Council work sessions (particularly during annual budget discussions), media engagement, and postcard mailings. Public Utilities is continuing to engage the public, and has retained the public engagement firm, Wilkinson Ferrari, to assist. We continue to provide updates to community councils, and will be holding public open houses starting April 2019. Because of the duration of the project, Public Utilities' engagement will be ongoing and iterative.

EXHIBITS:

A. Council Resolution Supporting the Reconstruction of the Salt Lake City Water Reclamation Facility

B. Engineering Estimated Cost for new WRF and Site Plan

C. Estimated Design and Construction costs and rate scenarios for new WRF from 2019-2025, as a component of overall Public Utilities Sewer Planning Budget
   i. Scenario 1 – Revenue Bonds and Rate Increases
   ii. Scenario 2 – Federal Water Infrastructure Finance Improvement Act (WIFIA) Loan and Rate Increases

D. WIFIA Fact Sheet

E. Official correspondence between Salt Lake City Department of Public Utilities and Utah Department of Environmental Quality establishing a permit variance for Technology-Based Phosphorus Effluent Limits, dated November 6, 2017 through March 21, 2019

Exhibit A

Council Resolution Supporting the Reconstruction of the Salt Lake City Water Reclamation Facility

RESOLUTION NO. ________ OF 2019

Supporting Water Reclamation Facility Upgrade

WHEREAS, the city's Public Utilities Department operates its Water Reclamation Facility (WRF) that treats approximately 35 million gallons of wastewater per day and the Department has been planning to upgrade and replace the WRF since 2015. The city operates the WRF pursuant to its State issued UPDES Discharge Permit No. UT0021725.

WHEREAS, the Utah Department of Environmental Quality (UDEQ) adopted a new rule that went into effect on January 1, 2016 (R317-3-3), limiting the amount of phosphorus permitted to be discharged by wastewater treatment plants into State water bodies. The new rule specifies compliance by January 1, 2020; however, the rule also allows for the Director of the UDEQ Water Quality Division to permit a variance to the compliance date if due diligence is made towards meeting the requirements of the rule;

WHEREAS, due to numerous issues associated with meeting the January 1, 2020 compliance date, including the age of the existing WRF, construction schedule, and procurement of funding, the Public Utilities Department requested a variance on March 26, 2018, to extend the compliance deadline. Conditional approval from UDEQ was received on May 29, 2018 to extend the compliance deadline to January 1, 2025;

WHEREAS, the Public Utilities Department is currently designing the new WRF. The design and construction costs have been planned within Public Utilities' budgets starting in fiscal year 2018, and through 2025. This includes bond revenue and design costs in the proposed FY 2020 budget. Currently, the estimated cost for construction of the new WRF is $528,130,000, with the construction to be phased over seven years with the objective of meeting the rule by 2024, one year ahead of the regulatory compliance deadline;

WHEREAS, UDEQ's approval of the variance requested by the Public Utilities Department includes certain conditions for the extension of time for compliance under Rule 317-3-3. One condition is that the City Council adopt a resolution supporting the pursuit of the WRF upgrade to achieve the permitted biological phosphorus levels; and

WHEREAS, the Public Utilities Department has provided to the City Council with adequate information for it to make an informed decision supporting the upgrade of the WRF facility.

THEREFORE, BE IT RESOLVED by the City Council of Salt Lake City, Utah, as follows:

The City Council of Salt Lake City, Utah does hereby support the pursuit of the WRF upgrade to achieve the selected biological phosphorus levels in order to comply with the standards established for Salt Lake City under its UPDES Discharge Permit; such upgrade will require the approximate budget of $528,130,000, which is subject to future appropriations of the City Council.

Passed by the City Council of Salt Lake City, Utah, this _____ day of _______________, 2019.

SALT LAKE CITY COUNCIL

By: ___________________________
CHAIRPERSON

ATTEST AND COUNTERSIGN:

____
CITY RECORDER

Approved as to form: ERL
Salt Lake City Attorney's Office
E. Russell Vetter, Deputy City Attorney
Date: 4/2/19

HB_ATTY-#76249-v1-Resolution_Supporting_WRF_Upgrade_3-19

Exhibit B

Engineering Estimated Cost for new WRF
and Site Plan

PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	BUDGET YEAR 2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	
		NEW WATER RECLAMATION FACILITY								
524905271		NEW PLANT - CORE DESIGN/BUILD RECLAMATION FACILITY	1,750,000	10,250,000	5,000,000	3,500,000	2,000,000	400,000		
524905335		WRF MASTER PLAN IMPLEMENTATION - CAPITAL PROJECT SUPPORT	4,500,000	4,500,000	4,500,000	3,500,000	3,500,000	2,500,000	1,500,000	
		NEW PLANT - MECHANICAL DEWATERING (CONSTRUCTION)	33,500,000	440,000						
		NEW PLANT - BNR LIQUID STREAM (CONSTRUCTION)		41,020,000	155,430,000	120,360,000	15,960,000			
		NEW PLANT - SOLIDS HANDLING (CONSTRUCTION)					41,160,000	2,840,000		
		NEW PLANT - ADMIN OPS (CONSTRUCTION)		14,090,000	1,620,000					
		NEW PLANT - DEMOLITION (CONSTRUCTION)						5,000,000	1,500,000	
525400068	2017-2050	NEW PLANT - PROFESSIONAL DESIGN SERVICES	9,500,000	7,800,000	7,500,000	5,100,000	2,100,000	2,000,000	1,000,000	
524905339	2017-2051	NEW PLANT - CM/GC DESIGN SERVICES	3,000,000	2,500,000	1,000,000					
524905337	2017-2052	NEW PLANT - WATER RENEW PUBLIC OUTREACH	300,000	250,000	250,000	250,000	250,000	250,000	250,000	
524905340	2017-2054	NEW PLANT - PILOTING AND DEMONSTRATION TESTING	2,000,000	2,000,000						
		NEW PLANT - PROJECT DOCUMENTATION	150,000	60,000	60,000	60,000	60,000	60,000	60,000	
		TOTAL CAPITAL IMPROVEMENTS	54,700,000	82,910,000	175,360,000	132,770,000	65,030,000	13,050,000	4,310,000	**528,130,000**

Basis of Estimate

Nutrient Project – Pre-Design Estimate
Salt Lake City
Water Reclamation Facility

Prepared for
Salt Lake City, Utah
Department of Public Utilities

February 8, 2018

Contents

SLCWRF – Nutrient Pre-Design Estimate
Basis of Estimate

TABLE 0.1
Estimate Information
SLC-WRF – 15pct Design

Estimate Classification	Class 4
Requested By	Brewer, Mike/SLC
Estimated By	Bredehoeft, Pete/ATL, Sisneros, Steve/DEN
Estimator Phone	678-373-3235
Estimate Date	February 8, 2018

1. Purpose of Estimate

The purpose of this estimate of construction cost is to establish an Engineer's opinion of probable construction cost at the predesign level. Design costs, construction management costs and Owner costs are being handled at the program level.

2. General Project Description

The Salt Lake City Water Reclamation Facility (SLCWRF) is located at 1365 West 2300 North, Salt Lake City, Utah. The wastewater treatment facility owned and operated by the Salt Lake City Department of Public Utilities (SLCDPU). This construction estimate is for the phase 1 improvement (only), which replaces the existing facility and maintains the capacity of the plant to 56 MGD (AAF). The improvements include: influent pipeline, influent pump station (off-site) screening & grit removal (on-site), primary treatment, secondary treatment, chemical treatment & storage, UV disinfection, solids handling upgrades, including a new dewatering building to replace drying beds, thermal-alkaline hydrolysis, post aerobic digestion, thermal drying and new Combined Heat & Power facilities. Other improvements include new administration building, utility water pump station, primary electrical services and distribution, and standby power systems, and improvements to the natural wetland treatment system.

3. Overall Costs

The following is a summary breakdown of the construction costs.

Accuracy Range - High		**Accuracy Range - Low**
+25%	**Construction Cost without Escalation**	**-20%**
$482,467,000	$ 385,973,000	**$ 308,779,000**
	Construction Cost with Escalation - 5.32% (Buy-out)	
$508,133,000	$ 406,506,000	**$ 325,205,000**

This cost estimate has been prepared for guidance in project evaluation and implementation from the information available at the time of the estimate. The final costs of the project will depend on actual labor and material costs, competitive market conditions, final project costs, implementation schedule and other variable factors. As a result, the final project costs will vary from the estimate presented herein. Because of this, project feasibility and funding needs must be carefully reviewed prior to making specific financial decisions to help ensure proper project evaluation and adequate funding.

4. Scope of Work

This project consists of the following areas of improvements or facilities:

- Contractor – Startup & Testing
- Sitework – including 15' of imported fill for new facilities – Phase 1 Only
- Yard Piping – 28,171' LF or 5.3 miles
- Bypass Pumping, Connections and Tie-ins – Allowance
- Demolition of Existing Drying Beds – 26 acres
- Demolition of Building and Structure – Phase 1
- Demolition of Building and Structures – Bid Items (Phase 2)
- Existing Electrical Upgrades – Allowance
- Influent Pipeline – 3 Runs x 54" Dia – 4,300 LF
- Influent Pump Station & Course Screening – Offsite
- Influent Pump Station Odor Control Pad - Offsite
- Influent Connection Junction Boxes - Offsite
- Influent Flow Meter Vault
- Headworks Building – Onsite
- Headworks Odor Control Pad
- Grit Basin Facility
- Primary Influent Splitter Box
- Primary Clarifiers – 185' Dia – 4 EA
- Primary Effluent Splitter Box
- Primary Sludge Pump Station
- Primary Scum Pump Station
- Bioreactor Splitter Box
- Bioreactor Basin
- Secondary Clarifiers – 210' Dia – 4 EA
- Secondary Scum Pump Station
- Return Activated Sludge Pump Station
- Return Activated Sludge Splitter Box
- Blower Building – 19,46 SF
- Chemical Building – 5,714 SF
- UV Disinfection Building - Reto-fit of Existing Aeration Basins.
- Combined Heat and Power (CHP) Building – 3,800 SF
- Administration Building – 2-Story - 10,000 SF
- Operations Building – 20,000 SF
- Post Aerobic Digestion Tank
- Post Aerobic Diegestion Mechanical Building – 8,236 SF
- Dewatering Building – 2-Story – 12,440 SF
- Dryer Building – 12,136 SF
- Utility Water Pump Station – Reto-fit of Existing Aeration Basins
- Plant Drain Pump Station

- Effluent Parshall Flume – Flow Meter
- Plant Generators – Outdoor Units – 1.5MW – 2 EA – At IPS
- Plant Generators – Outdoor Units – 12.5MW – 4 EA – At WRF

5. Markups

These markups are based upon general assumptions about how the project will be contracted. Actual markup percentages may vary from those shown here, and are the responsibility of the bidding contractor.

TABLE 5.1
General Contractor Markups
Project Name

Contractor General Conditions	8.00%
Sales Tax on Material – Salt Lake City	6.85%
Contractor Overhead Home Office	4.00%
Contractor Profit	6.00%
Bonds and Insurance	2.16%
Estimate Contingency	10.00%
Escalation Rate – Based upon Contractor Buyout – 4 Months	5.32%

6. Escalation Rate

This estimate includes Escalation with the assumption that construction NTP will start in March 2020 with the midpoint of construction being June 2022. It is assumed that there will be 50 months (4.2 years) of construction duration. The full escalation of the project equates to an escalation factor of 10.81%. However, the escalation included in the cost estimate is based upon a 4-month contractor buyout or locking in of major equipment purchases and securing of subcontractors. This buyout escalation equates to be an escalation factor of 5.32%. (See appendix for Escalation Analysis.) The buyout escalation factor amount was used in this estimate.

This estimate assumes the project is based upon a design, bid, build contracting approach with single contract award. Phasing of construction packages is unknown and will be determined at a later date. This estimate assumes the NTP for a designer will be April 1, 2018, with a 24 month design period. The bid and award period for the construction contract will be based upon the CM At Risk procurement and be concurrent with the Design.

This CH2M HILL escalation forecast is based upon economic data from Global Insight, Inc. and the United States Bureau of Labor Statistics.

7. Estimate Classification

This cost estimate prepared is considered a feasibility or Class 4 estimate as defined by the Association for the Advancement of Cost Engineering International (AACE). It is considered accurate to +25% to -20%, based on a 15% pre-design deliverable.

8. Estimate Methodology

This cost estimate is considered a bottom rolled up type estimate with cost items and breakdown of Labor, Materials and Equipment. Process equipment quotations were obtained for the majority of major equipment. The estimate includes detailed takeoff and pricing for all divisions of work. The estimate may include allowance cost for plumbing

and HVAC. Other general allowances have been included in the estimate. Dollars per SF cost for the Administration and Operations buildings.

9. Cost Resources

The following is a list of the various cost resources used in the development of the cost estimate:

- CH2M HILL Historical Data
- R.S. Means
- Vendor Quotes on Equipment and Materials where appropriate
- Estimator Judgment

10. Labor Costs

The estimate has been adjusted for local area labor rates, based upon Davis Bacon rates for Salt Lake City, UT, 2017 rates.

Labor unit prices reflect a burdened rate, including: workers compensation, unemployment taxes, Fringe Benefits, and medical insurance.

11. Taxes

An 6.85% sales tax for Salt Lake City was added to all material costs within the estimate including process equipment. However, Certain pollution control facilities are exempt from sales tax "R865-19S-83. Pollution-Control Facilities Pursuant to Utah Code Ann. Section 59-12-104). An adjustment for tax exception has not been included in this estimate.

12. Major Assumptions

The estimate is based on the assumption the work will be done on a competitive bid basis and the contractor will have a reasonable amount of time to complete the work. All contractors are equal, with a reasonable project schedule, no overtime, constructed as under a single contract, no liquidated damages.

This estimate should be evaluated for market changes after 90 days of the issue date. It is assumed that much of the fabricated equipment will be shipped from the mainland USA.

Yard Piping

1. If a discrepancy on yard piping with facility exposed piping, the size shown on the yard piping will dictate. The facility drawing size will dictate on the exposed piping.

Grit Basin Facility

1. Influent Well Slab – Assumed 24" thick.
2. Cutthroat Flow Channel Slab – Assumed 18" thick.
3. Influent Flow Channels Slab – Assumed 18" thick.
4. Grit Basin Slab – Assumed 18" thick.

Primary Clarifiers

1. Base Slab – Assumed average of 16" thick.

Primary Sludge Effluent Splitter Box

1. Base Slab – Assumed 30" thick.

Primary Scum Pump Station

1. Pumps – Assumed 15hp

Secondary Scum Pump Station

1. Pumps – Assumed 15hp

Bioreactors

1. Base Slab – Assumed 36" thick.

Blower Building

1. Base Slab – Assumed 18" thick.

Secondary Clarifiers

1. Base Slab – Assumed 24" thick.

RAS/WAS Pump Station

1. Base Slab – Assumed 24" thick.
2. RAS Pumps – Assumed VFD is required and included in estimate.

Utility Water Pump Station

1. Non-Potable Water – Small Pumps – Assumed Vertical Turbine Pumps – 50hp/EA.

RAS Splitter Box

1. Base Slab – Assumed 30" thick.

Chemical Building

1. Base Slab – Assumed 18" thick

UV Disinfection Facility

1. Assumed new building is only over new channel space only, and extends out into new truck bay area.
2. Assumed new truck bay area base slab is 18" thick.

Post Aerobic Digestion

1. Base Slab – Assumed 24" thick

Post Aerobic Digestion Mechanical Building

1. Base Slab – Assumed 24" thick
2. Tank Wall – Assumed 24" thick

Dewatering Building

1. Base Slab – Assumed 24" thick.
2. Sludge Storage Pad – Assumed 24" thick with 4' high containment wall. Included an allowance for water collection of sludge water.

CHP Building

1. Base Slab in Engine Area – Assumed 36" thick, 12" in Electrical Room

Existing Electrical System Upgrades – Allowance

1. Existing Electrical System Upgrades – Assumed 6 men for 6 months and $1,500,000 material allowance.

Headworks Building

1. Lower Base Slab – Assumed 36" thick.
2. Perimeter Walls – Assumed 24" thick.
3. Building – Assumed CMU block with Double Tee Roof. Assumed 32' overall height.
4. Assumed 4 Ton Bridge Crane.

5. Special Coatings – Assumed T-Loc liner for all channels.
6. Footprint 144' by 60'
7. The building will sit on 15' of compacted fill at the new WRF
8. 4 bar screens
9. One extra spot for a 5th screen at final build out
10. 2 compactors
11. 2 loadout bays

Effluent Parshall Flume

1. Assumed new open channel, 200' Long x 5' wide x 8' high walls. Cast in place construction is assumed.
2. Flow Meter insert for Parshall Flume
3. Assumed grating over top of open channel.
4. Assumed a concrete 6' wide cantilevered deck x 200' long with stairs and handrail

Wetlands – Rock Weir and Spillway

1. The rock weir and spillway is constructed of 12"-18" rip-rap material, with filter fabric.
2. The approximate dimensions are 100' long x 17' wide x an average of 4' high.
3. Grading of Wetlands is based upon drawing C-14-100

Plant Drain Pump Station

1. Assumed plant drain system is the same as the Primary and Secondary scum pump station.

Electrical

1. Have used the Electrical One-line Drawings as reference for major electrical gear and MCC's.
2. Electrical Gear as shown on electrical one-lines costs are based on estimator judgment and previous project cost.
3. Generators cost include belly fuel tank and sound enclosure placed on slab exposed to environment.
4. Generator Switch Gear, includes costs for weather-proof enclosure to be located on slab exposed to environment.
5. Electrical one-lines for power distribution requirements, made assumptions and best judgment for general routing.
6. Duct-bank cost allowances based on estimator judgement and past projects of similar design.
7. Over-head Power cost allowances based on estimator judgement.
8. Utility Transformers carried in estimate as depicted on Electrical One-lines (Utility power feed and source to be supplied by Utility Company).
9. General electrical requirements, such building electrical, HVAC, etc. cost is accounted for in the Facility Electrical Allowance.

Instrumentation and Control (I & C)

1. Contractor Programming – Included cost for contractor to provide programming of installed equipment only.
2. I & C - Is estimated based on historical standard percentages used for typical facilities and processes.

Influent Pipeline

1. Pipeline – 54" Dia x 3 Run x 4,300' LF – Assumed HDPE pipe, glass line.
2. Pipeline – assumed pipeline is at mimimum buried depth.
3. Pipeline – assumed 10% for sheeting and shoring is required – 15' Embed.
4. Pipeline – assumed 20% requires well point dewatering for 4 months.
5. Pipeline – assumed no pipeline crossings.
6. Pipeline – assumed no pavement pavement restoration or improvements.
7. Pipeline – assumed hydro seeding along route, 4,300 LF x 50'wide.

Influent Pipeline – Connection Boxes

1. 1 interceptor box for pipelines at 15' by 28' by 30' deep
2. 1 interceptor box for pipelines at 14' by 12' by 30' deep
3. 1 junction box for pipelines at 14' by 34' by 30' deep
4. 280 feet of 48 inch dia. FRPMP pipeline @ 30 feet deep
5. 350 feet of 84 inch dia. FRPMP pipeline @ 30 feet deep
6. 70 feet of 96 inch dia. FRPMP pipeline @ 30 feet deep

Influent Pump Station

1. Existing plant footprint approx. 7,500 ft. sq.
2. Use 9,750 ft. sq. – 30% larger
3. 30 feet deep
4. Existing pumps 4 ea. @ 350 Horsepower
5. New pump use 4 ea. @ 770 Horsepower – approx. 30% larger
6. Space for 1 additional pump at final build out
7. New pump station will have an odor control facility
8. No additional pump station will be required at the new WRF

Sitework

1. Demolition of Existing Roadway Pavement – assumed 6" overall depth.
2. New Asphalt Pavement – Assumed 8" base stone course, 3" asphalt base course, 2" asphalt wearing course.
3. Sidewalks – assumed 5% of asphalt pavement area.
4. Stormwater System – Allowance – 8,000 LF of 36" – 18" RCP Pipe and 40 catch basins.
5. Gas Utilities – Allowance – 5,000 LF of 2" Dia pipe.
6. Dump Charge – Assume County Landfill will be used. This could be a potential large project savings if the City could negotiate waving or a lower disposal fee charge.
7. Imported Fill – Overall site has 15' of imported material. Assumed clean fill, imported from 10 miles round trip at a cost of $9.00/CY. Imported fill is only in new facilities area, located at the demolished sludge drying beds and phase 1 work area only.
8. Hauling – assumed 10 miles round trip for hauling of offsite soil waste material.
9. Disposal or Dump Fee is based upon Salt Lake County Landfill prices:
   a. Construction Debris - $31.35/TON
   b. Asphalt/Concrete $5.00/Ton
   c. Soil Disposal - $5.35/Ton
   d. Assumed contractor will sort and separate concrete and rebar to minimize cost.
10. Dewatering – Since overall site has 15' of fill material – assumed well point dewatering is required for any facility deeper than 12' deep.
11. Shoring – Assumed facility depths over 12' deep will require sheeting and shoring to keep out dewatering and for working space for construction of that facility.
12. Imported Fill:
    a. Imported 15' – Clean Fill – 880,000 CY
    b. Scarify, Compaction, Rough and Final Grading – 153,000 SY
13. Seeding Construction Area – 860,000 SF
14. Asphalt Pavement – 375,000 SF

Demolition

The demolition of existing sludge drying beds and various facilities, includes the following assumptions:

1. Asphalt Pavement demolition – 325,000 SF
2. Sludge Drying Beds:

   a. Assumed SLC staff will removal and clean out all existing sludge and sludge water prior to contractor demolishing the sludge drying beds.
   b. Assumed 6" of concrete will be demolished and hauled off site, 21,200 CY.
   c. Assumed 1.5' of berm material and contaminated sludge material, 63,400 CY will be hauled off site.
3. Aeration Basin – 10 crew days to demolish.
4. Tower Structure – 10 crew days to demolish.
5. Bid Options:
   a. Blower Building – 7 crew days to demolish
   b. Chemical Building – 5 crew days to demolish
   c. Chlorine Contact Basin – 10 crew days to demolish
   d. Primary Clarifiers 140' dia – 4 EA – 20 crew days to demolish
   e. Secondary Clarifiers 140' dia – 4 EA – 20 crew days to demolish
   f. Trickling Filters 190' Dia – 4 EA – 20 crew days to demolish

Startup and Testing

1. Assumed contractor startup and testing period of 4 months.

Special Coatings

1. T-Loc Liner is included for the base slab, walls, channels and upper elevated slab on the following facilities:
   a. Influent pump station.
   b. Influent junction boxes.
   c. Headworks.
   d. Grit basin facility.
2. Special Coatings – Epoxy Flooring is included in the following facilities:
   a. Blower building.
   b. Chemical building.
   c. CHP building
   d. Post aerobic digestion mechanical building.
   e. Dewatering building.
   f. Dryer building.

Labor Availability

1. Assumed adequate availability of construction labor, across all trades. This should be evaluated as the design progresses for current market conditions. The airport expansion project and prison expansion project may affect labor resources on the WRF project. No adjustment to the estimate has been made at this time.

Contracting Strategy

1. The Construction Contact will be a CM At Risk contract, with the Guaranteed Construction amount developed at a 90 percent design level.
2. The phasing of construction packages has not been flushed out at the time of the estimate. However, it is anticipated that the Dewatering Building maybe the first contract construction package. The second construction package could be the Headworks, Grit Screening, Influent Pump Station, Influent Junction Boxes, Influent Meter Vault and Demolition of Existing Drying Beds.
3. The final construction phasing schedule would be developed at the GMP development.

13. Key Project Quantities

The following are overall plant wide key project quantities, summary information:

Facility Name	Concrete CY	Earthwork Excavation CY	Excavation Depth Ft	Sheeting and Shoring SF	Dewatering MO	Buried Pipe LF	Process Pipe LF
Sitework - Imported 15' Clean Fill		880,000					
Yard Piping		80,505	9	147,200	9	28,171	
Influent Pipeline - Twin 60" Dia - 3,600 LF		52,799	12	21,600	2	7,200	
Influent Pump Station & Junction Boxes - Off-site	8,193		32	64,973	33	875	880
Influent Meter Vault	309	1,900	34	9,900	5		
Influent Pump Station Odor Control Pad - Off-site	217	575	2				50
Headworks - On-Site	2,503	15,400	37	24,696	12	175	700
Grit Basin Facility - On-Site	2,111	10,900	13	18,414	10		600
Headworks - Odor Control Pad - On-site	217	575	2				300
Primary Effluent Splitter Box	391	2,500	17	6,160	4		
Primary Influent Splitter Box	391	2,500	17	6,160	4		
Bioreactor Splitter Box	391	2,500	17	6,160	4		
Primary Sludge Pump Station	308	3,250	16	5,796	4		584
Primary Clarifiers - 4 EA	10,920	63,500	12			460	
Primary Scum Pump Station		225	9			20	50
Secondary Scum Pump Station		225	9			20	50
Plant Drain Pump Station		225	9			20	50
Bioreactors	38,789	289,800	31	79,376	18		6,752
Secondary Clarifiers - 4 EA	17,607	82,100	12			1,200	
Return Activated Sludge Pump Station	673	3,600	8				1,235
Return Activated Sludge Spitter Box	441	3,300	23	6,750	6		16
Blower Building	1,244	5,700	7				2,925
Chemical Building	623	2,800	9				1,200
UV Disinfection Facility	85						
Effluent Parshall Flume - Flow Meter	595	4,100	21	13,272	6		
CHP Building	406	2,200	8				800
Utility Water Pump Station	40						250
Post Aeration Digestion Tank	1,587	13,900	32	15,523	6		
Post Aeration Digestion Mechanical Building	564	3,100	7				2,240
Dewatering Building	2,142	6,100	9			500	2,500
Dryer Building	2,888	6,600	10				1,000
Plant Generator - 6 EA	1,167	850	5				
OVERALL PLANT - TOTALS	**94,801**	**1,541,729**	**425**	**425,980**	**123**	**38,641**	**22,182**

14. Allowances

The estimate includes allowances for known work that is not sufficiently detailed at this time:

- Bypass pumping, tie-in connections and temporary facilities
- Yard Piping – site wide – Allowance for well point dewatering – 9 months.
- Miscellaneous metals allowances
- Interior painting allowance
- Toilet rooms allowance at Headworks
- Stormwater allowance
- Natural gas allowance
- Dryer exhaust system allowance
- Administration Building – 10,000 SF - $550/SF direct cost – Single story, includes office space, reception, conference rooms, training rooms, and break rooms.

- Operations Building – 20,000 SF - $250/SF direct cost – Single story, includes office space, conference rooms, training rooms, maintenance space, storage, operations room and operations laboratory.

15. Excluded Costs

The cost estimate excludes the following costs:

- Phase 2 improvements are not included in the construction cost estimate.
- Demolition of existing influent pump station is not included in this cost estimate.
- Demolition of existing screening facility is not included in this cost estimate.
- Demolition of existing CHP building is not included in this cost estimate.
- Demolition of existing administration building is not included in this cost estimate.
- Existing Sludge Ponds - Assumed SLC staff will removal and clean out all existing sludge and sludge water prior to contractor demolishing the sludge drying beds. Excluded this work.
- Replacement of any existing process equipment with new equipment is not included.
- Concrete or structural repair of existing structures are not included.
- Pile Foundations or Soil Treatment is not included in the cost estimate.
- Plantwide automation integration is excluded.
- Wetland improvement and mitigation items are excluded.
- Concrete Curb and Gutter is excluded.
- New security or chain-link fence is excluded.
- Open Space improvements are excluded.
- Stormwater ponds or bioretention ponds are excluded.
- Landscaping costs are excluded.
- Imported fill for phase 2 facilities is excluded.
- The cost for to incorporate "Envision" guidelines for incorporate principles for sustainable civil infrastructure have not been included in this cost estimate.
- Utility Power Source or feed into the plant has been excluded from this estimate.
- Labor shortage of resources is excluded.
- State Sale Tax Exemption has not been included in this estimate.
- Non-construction or soft costs for design, services during construction, land, legal and owner administration costs
- Material Adjustment allowances above and beyond what is included at the time of the cost estimate

16. Reference Documents

This cost estimate is based upon Water Works 15% Pre-Design Drawings and Design Report, dated August 2017.

N

SCALE IN FEET

KEYNOTES

1 WETLANDS
2 ADMINISTRATION BUILDING
3 EFFLUENT HEAT RECOVERY FACILITY
4 TERTIARY FILTRATION FACILITY
5 DISINFECTION FACILITY
6 EQUIPMENT STORAGE BUILDING
7 SECONDARY CLARIFICATION FACILITY
8 ADMINISTRATION BUILDING (EXISTING)
9 OUTFALL
10 BIOLOGICAL NUTRIENT REMOVAL FACILITY
11 OPERATIONS & MAINTENANCE BUILDING
12 WASTE ACTIVATED SLUDGE GRAVITY THICKENING FACILITY (EXISTING)
13 WASTE ACTIVATED SLUDGE MECHANICAL THICKENING FACILITY (EXISTING)
14 COMBINED HEAT & POWER FACILITY (EXISTING)
15 COUNTY PUMPS 1-4
16 SLUDGE STORAGE PAD
17 BLOWER BUILDING
18 PRIMARY CLARIFICATION FACILITY
19 THERMAL DRYING FACILITY
20 DEWATERING FACILITY
21 COMBINED HEAT & POWER FACILITY
22 DIGESTION FACILITY (EXISTING)
23 RESOURCE RECOVERY FACILITY
24 WEST MAINTENANCE (EXISTING)
25 HEADWORKS FACILITY
26 SEPTAGE RECEIVING STATION
27 INFLUENT PUMP STATION
28 BIOLOGICAL NUTRIENT REMOVAL TRAINING FACILITY
29 STAND-BY POWER
30 ELECTRICAL SUBSTATION
31 HAULED WASTE RECEIVING STATION
32 STOREHOUSE
33 CHEMICAL STORAGE FACILITY
34 CONSTRUCTION STAGING AREA

LEGEND

- NON-PROCESS FACILITIES NEW / EXISTING
- LIQUID STREAM FACILITIES NEW / EXISTING
- SOLIDS STREAM FACILITIES NEW / EXISTING
- FUTURE FACILITIES

KEY PLAN

SCALE: 1" = 150'

VERIFY SCALE
BAR IS ONE INCH ORIGINAL DRAWING

DESIGNED BY:
DRAWN BY:
CHECKED BY:
APPROVED BY:
DATE:
EWO NO:
ACCOUNT NO:

REVISIONS

NO	DATE		MADE BY	AUTH BY

SALT LAKE CITY DEPARTMENT OF PUBLIC UTILITIES
WATER RECLAMATION FACILITY UPGRADE

OVERALL SITE PLAN

PRELIMINARY NOT FOR CONSTRUCTION

DRAWING No
XX-010-C102

SHEET ___ OF ___

Exhibit C

Estimated Design and Construction costs and rate scenarios for new WRF from 2019-2025, as a component of overall Public Utilities Sewer Planning Budget

i. Scenario 1 – Revenue Bonds and Rate Increases
ii. Scenario 2 – Federal Water Infrastructure Finance Improvement Act (WIFIA) Loan and Rate Increases

SEWER UTILITY
Planning Budget
FY20 Budget
and FY2020-2026 Forecast

+18%,20%,25%,25%,10%,10% Rate Increases
$0 in WIFIA Funds
$523M in Bonds,$55M,$107M,$187M,$138M,$69M,$17M
New Debt Pmts $109M FY 20-26
$528M New WRF in CIP

	ACTUAL YEAR 2017-2018	PROJECTED YEAR 2018-2019	BUDGET YEAR 2019-2020	BUDGET YEAR 2020-2021	BUDGET YEAR 2021-2022	BUDGET YEAR 2022-2023	BUDGET YEAR 2023-24	BUDGET YEAR 2024-25	BUDGET YEAR 2025-26
SEWER SALES	$33,620,751	$37,677,666	$44,460,000	$53,733,000	$67,642,000	$85,148,000	$94,317,000	$104,468,000	$115,705,000
OTHER INCOME	662,733	255,000	255,000	255,000	255,000	255,000	255,000	255,000	255,000
INTEREST INCOME	1,579,221	1,052,000	604,000	21,000	21,000	23,000	1,090,000	29,000	30,000
OPERATING INCOME	35,862,705	38,984,666	45,319,000	54,009,000	67,918,000	85,426,000	95,662,000	104,752,000	115,990,000
NEW PLANT O&M COSTS			0	0		(250,000)	(252,500)	(255,025)	(257,575)
OPERATING EXPENSES	(15,354,771)	(19,425,617)	(21,024,164)	(21,780,388)	(22,448,209)	(23,138,679)	(23,852,612)	(24,375,034)	(24,862,535)
NET INCOME EXCLUDING DEP.	20,507,934	19,559,049	24,294,836	32,228,612	45,469,791	62,037,321	71,556,888	80,121,941	90,869,890
IMPACT FEES	971,344	700,000	700,000	724,500	749,858	776,103	803,267	831,381	860,479
STATE LOAN (NWQ)	8,500,000								
SHORT TERM FINANCING PROCEEDS									
WIFIA LOAN									
NET BOND PROCEEDS	0		55,000,000	106,000,000	182,000,000	125,000,000	55,000,000		
ISSUE COSTS (PROCEEDS)			307,000	592,000	1,016,000	698,000	307,000	0	0
ISSUE COSTS (EXP)			(307,000)	(592,000)	(1,016,000)	(698,000)	(307,000)	0	0
OTHER CONTRIBUTIONS	978,525	2,020,000	2,020,000	2,020,000	720,000	520,000	520,000	520,000	520,000
CAPITAL OUTLAY	(847,714)	(1,302,569)	(8,694,000)	(823,000)	(823,000)	(823,000)	(823,000)	(823,000)	(823,000)
STATE LOAN DEBT REPAYMENT			(6,375,000)	(2,125,000)					
NEW DEBT SERVICE		0	(719,000)	(3,632,000)	(9,266,000)	(16,583,000)	(22,553,000)	(26,528,000)	(30,109,000)
DEBT SERVICE	(5,561,477)	(6,050,603)	(6,055,000)	(8,574,000)	(8,560,000)	(8,561,000)	(8,935,850)	(8,561,000)	(8,561,000)
OTHER INCOME & EXPENSE	4,040,678	(4,633,172)	35,877,000	93,590,500	164,820,858	100,329,103	24,011,417	(34,560,619)	(38,112,521)
NET FOR CAPITAL	24,548,612	14,925,877	60,171,836	125,819,112	210,290,649	162,366,424	95,568,305	45,561,322	52,757,369
CAPITAL IMPROVEMENTS	$ (33,243,806)	$ (60,892,051)	$ (98,370,500)	(125,728,000)	(210,160,000)	(162,630,000)	(94,660,000)	(45,480,000)	(30,321,000)
NEW WRF IN CIP			$ (54,700,000)	(82,910,000)	(175,360,000)	(132,770,000)	(65,030,000)	(13,050,000)	(4,310,000)
CASH INCREASE/(DECREASE)	(8,695,194)	(45,966,174)	(38,198,664)	91,112	130,649	(263,576)	908,305	81,322	22,436,369
		0							
BEGINING CASH BALANCE	94,916,245	86,221,051	40,254,877	2,056,213	2,147,325	2,277,974	2,014,398	2,922,703	3,004,025
CASH INCREASE/(DECREASE)	(8,695,194)	(45,966,174)	(38,198,664)	91,112	130,649	(263,576)	908,305	81,322	22,436,369
ENDING BALANCES	**86,221,051**	**40,254,877**	**2,056,213**	**$2,147,325**	**$2,277,974**	**$2,014,398**	**$2,922,703**	**$3,004,025**	**$25,440,394**
RESTRICTED/RESERVED	**(10,789,378)**								
AVAILABLE ENDING BALANCE	**$75,431,673**	**$40,254,877**	**$2,056,213**	**$2,147,325**	**$2,277,974**	**$2,014,398**	**$2,922,703**	**$3,004,025**	**$25,440,394**
RATE CHANGE	30%	15%	18%	20%	25%	25%	10%	10%	10%
Cash Reserve Ratio	562%	207%	10%	10%	10%	9%	12%	12%	101%
Debt Service Coverage	3.69	3.23	1.85	2.25	2.55	2.47	2.27	2.28	2.35
DEBT SERVICE % OF GROSS OPERATING REVENUE	16%	16%	15%	23%	26%	29%	33%	33%	33%
MONTHLY RESIDENTIAL UTILITY BILL AT 4 CCF	10.60	12.16	14.68	17.62	22.03	27.54	30.29	33.32	36.65
MONTHLY RESIDENTIAL UTILITY BILL AT 8 CCF	21.20	24.32	29.36	35.23	44.04	55.05	60.56	66.62	73.28

SEWER UTILITY
Planning Budget
FY20 Budget
and FY2020-2026 Forecast

+18%,18%,18%,15%,10%,10% Rate Increases
$259M in WIFIA Funds
$283M in Bonds,$55M,$39M,$97M,$65M $27M
New Debt Pmts $45M FY 20-26
$528M New WRF in CIP

	ACTUAL YEAR 2017-2018	PROJECTED YEAR 2018-2019	BUDGET YEAR 2019-2020	BUDGET YEAR 2020-2021	BUDGET YEAR 2021-2022	BUDGET YEAR 2022-2023	BUDGET YEAR 2023-24	BUDGET YEAR 2024-25	BUDGET YEAR 2025-26
SEWER SALES	$33,620,751	37,677,666	44,460,000	$52,838,000	$62,791,000	$72,718,000	$80,548,000	$89,216,000	$98,812,000
OTHER INCOME	662,733	255,000	255,000	255,000	255,000	255,000	255,000	255,000	255,000
INTEREST INCOME	1,579,221	1,052,000	604,000	23,000	29,000	31,000	30,000	28,000	62,000
OPERATING INCOME	35,862,705	38,984,666	45,319,000	53,116,000	63,075,000	73,004,000	80,833,000	89,499,000	99,129,000
NEW PLANT O&M COSTS			0	0		(250,000)	(252,500)	(255,025)	(257,575)
OPERATING EXPENSES	(15,354,771)	(19,425,617)	(21,024,164)	(21,780,388)	(22,448,209)	(23,138,679)	(23,852,612)	(24,375,034)	(24,862,535)
NET INCOME EXCLUDING DEP.	20,507,934	19,559,049	24,294,836	31,335,612	40,626,791	49,615,321	56,727,888	64,868,941	74,008,890
IMPACT FEES	971,344	700,000	700,000	724,500	749,858	776,103	803,267	831,381	860,479
STATE LOAN (NWQ)	8,500,000								
SHORT TERM FINANCING PROCEEDS									
WIFIA LOAN				67,429,000	85,926,000	65,057,000	31,865,000	6,395,000	2,112,000
NET BOND PROCEEDS			55,000,000	39,000,000	97,000,000	65,000,000	27,000,000		
ISSUE COSTS (PROCEEDS)			307,000	218,000	542,000	363,000	151,000	0	0
ISSUE COSTS (EXP)			(307,000)	(218,000)	(542,000)	(363,000)	(151,000)	0	0
OTHER CONTRIBUTIONS	978,525	2,020,000	2,020,000	2,020,000	720,000	520,000	520,000	520,000	520,000
CAPITAL OUTLAY	(847,714)	(1,302,569)	(8,694,000)	(823,000)	(823,000)	(823,000)	(823,000)	(823,000)	(823,000)
STATE LOAN DEBT REPAYMENT			(6,375,000)	(2,125,000)					
NEW DEBT SERVICE		0	(719,000)	(2,700,000)	(5,216,000)	(9,091,000)	(12,731,000)	(14,415,000)	(16,324,000)
DEBT SERVICE	(5,561,477)	(6,050,603)	(6,055,000)	(8,574,000)	(8,560,000)	(8,561,000)	(8,935,850)	(8,561,000)	(8,561,000)
OTHER INCOME & EXPENSE	4,040,678	(4,633,172)	35,877,000	94,951,500	169,796,858	112,878,103	37,698,417	(16,052,619)	(22,215,521)
NET FOR CAPITAL	24,548,612	14,925,877	60,171,836	126,287,112	210,423,649	162,493,424	94,426,305	48,816,322	51,793,369
CAPITAL IMPROVEMENTS	$ (33,243,806)	(60,892,051)	(98,370,500)	(125,728,000)	(210,160,000)	(162,630,000)	(94,660,000)	(45,480,000)	(30,321,000)
NEW WRF IN CIP			(54,700,000)	(82,910,000)	(175,360,000)	(132,770,000)	(65,030,000)	(13,050,000)	(4,310,000)
CASH INCREASE/(DECREASE)	(8,695,194)	(45,966,174)	(38,198,664)	559,112	263,649	(136,576)	(233,695)	3,336,322	21,472,369
		0							
BEGINING CASH BALANCE	94,916,245	86,221,051	40,254,877	2,056,213	2,615,325	2,878,974	2,742,398	2,508,703	5,845,025
CASH INCREASE/(DECREASE)	(8,695,194)	(45,966,174)	(38,198,664)	559,112	263,649	(136,576)	(233,695)	3,336,322	21,472,369
ENDING BALANCES	**86,221,051**	**40,254,877**	**2,056,213**	**$2,615,325**	**$2,878,974**	**$2,742,398**	**$2,508,703**	**$5,845,025**	**$27,317,394**
RESTRICTED/RESERVED	**(10,789,378)**								
AVAILABLE ENDING BALANCE	**$75,431,673**	**40,254,877**	**2,056,213**	**$2,615,325**	**$2,878,974**	**$2,742,398**	**$2,508,703**	**$5,845,025**	**$27,317,394**
RATE CHANGE	30%	15%	18%	18%	18%	15%	10%	10%	10%
Cash Reserve Ratio	**562%**	**207%**	**10%**	**12%**	**13%**	**12%**	**10%**	**24%**	**109%**
Debt Service Coverage	**3.69**	**3.23**	**1.85**	**2.34**	**2.95**	**2.81**	**2.62**	**2.82**	**2.97**
DEBT SERVICE % OF GROSS OPERATING REVENUE	16%	16%	15%	21%	22%	24%	27%	26%	25%
MONTHLY RESIDENTIAL UTILITY BILL AT 4 CCF	10.60	12.16	14.68	17.32	20.44	23.51	25.86	28.45	31.30
MONTHLY RESIDENTIAL UTILITY BILL AT 8 CCF	21.20	24.32	29.36	34.64	40.88	47.01	51.71	56.88	62.57

Exhibit D

WIFIA Fact Sheet

WIFIA PROGRAM

The WIFIA program accelerates investment in our nation's water infrastructure by providing long-term, low-cost supplemental loans for regionally and nationally significant projects. The WIFIA program was established by the Water Infrastructure Finance and Innovation Act of 2014.

ELIGIBILITY

Eligible borrowers

- Local, state, tribal, and federal government entities
- Partnerships and joint ventures
- Corporations and trusts
- Clean Water and Drinking Water State Revolving Fund (SRF) programs

WIFIA can fund development and implementation activities for eligible projects

- Wastewater conveyance and treatment projects
- Drinking water treatment and distribution projects
- Enhanced energy efficiency projects at drinking water and wastewater facilities
- Desalination, aquifer recharge, and water recycling projects
- Acquisition of property if it is integral to the project or will mitigate the environmental impact of a project
- A combination of eligible projects secured by a common security pledge or submitted under one application by an SRF program

FUNDING AVAILABILITY

EPA announces WIFIA funding availability and application process details in the Federal Register and on its website.

IMPORTANT PROGRAM FEATURES

$20 MIL — Minimum project size for large communities.

$5 MIL — Minimum project size for small communities (population of 25,000 or less).

49% — Maximum portion of eligible project costs that WIFIA can fund.

35 YEARS — Maximum final maturity date from substantial completion.

5 YEARS — Maximum time that repayment may be deferred after substantial completion of the project.

% — Interest rate will be equal or greater to the US Treasury rate of a similar maturity.

Projects must be creditworthy.

NEPA, Davis-Bacon, American Iron and Steel, and all federal cross-cutter provisions apply.

EPA

STAY IN TOUCH

WEBSITE: www.epa.gov/wifia

EMAIL: wifia@epa.gov

Sign-up to receive announcements about the WIFIA program at https://tinyurl.com/wifianews

November 2016

EPA-830-F-16-003

WIFIA PROGRAM

The Water Infrastructure Finance and Innovation Act (WIFIA) program accelerates investment in our nation's water infrastructure by providing long-term, low-cost supplemental loans for nationally and regionally significant projects. Borrowers benefit from receiving low, fixed interest rate loans with flexible financial terms.

WIFIA LOANS OFFER A LOW, FIXED INTEREST RATE

A SINGLE FIXED RATE IS ESTABLISHED AT CLOSING. A borrower may receive multiple disbursements over several years at the same fixed interest rate.

RATE IS EQUAL TO THE US TREASURY RATE OF A SIMILAR MATURITY. The WIFIA program sets its interest rate based on the U.S. Treasury rate on the date of loan closing. The rate is calculated using the weighted average (WAL) life of the loan rather than the loan maturity date. The WAL is generally shorter than the loan's actual length resulting in a lower interest rate.

RATE IS NOT IMPACTED BY BORROWER'S CREDIT OR LOAN STRUCTURE. All borrowers benefit from the AAA Treasury rate, regardless of whether they are rated AA or BBB. The WIFIA program does not charge a higher rate for flexible financial terms.

WIFIA LOANS PROVIDE FLEXIBLE FINANCIAL TERMS

CUSTOMIZED REPAYMENT SCHEDULES. Borrowers can customize their repayments to match their anticipated revenues and expenses for the life of the loan. This flexibility provides borrowers with the time they may need to phase in rate increases to generate revenue to repay the loan.

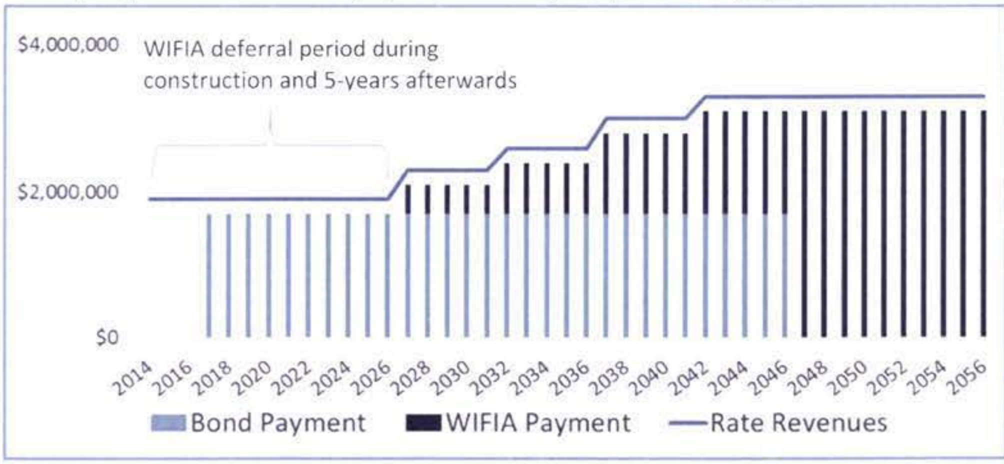
LONG REPAYMENT PERIOD. WIFIA loans may have a length of up to 35 years after substantial completion, allowing payment amounts to be smaller throughout the life of the loan.

DEFERRED PAYMENTS. Payments may be deferred up to 5 years after the project's substantial completion.

SUBORDINATION. Under certain circumstances, WIFIA may take a subordinate position in payment priority, increasing coverage ratios for senior bond holders.

WIFIA LOANS CAN BE COMBINED WITH VARIOUS FUNDING SOURCES. WIFIA loans can be combined with private equity, revenue bonds, corporate debt, grants, and State Revolving Fund (SRF) loans.

Example of a customized debt repayment structure for a $100 million project



WIFIA loan's flexible repayment schedule allows for rate increases to be phased in over a longer period of time.

EPA

WEBSITE: www.epa.gov/wifia
EMAIL: wifia@epa.gov
ANNOUNCEMENTS: Sign-up at https://tinyurl.com/wifianews

Exhibit E

Official correspondence between Salt Lake City Department of Public Utilities and Utah Department of Environmental Quality establishing a permit variance for Technology-Based Phosphorus Effluent Limits, dated November 6, 2017 through March 21, 2019

State of Utah
GARY R. HERBERT
Governor

SPENCER J. COX
Lieutenant Governor

Department of
Environmental Quality

Alan Matheson
Executive Director

DIVISION OF WATER QUALITY
Erica Brown Gaddis, PhD
Director

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March 21, 2019

Laura Briefer
Director of Department of Public Utilities
Salt Lake City Corporation
1530 South West Temple
Salt Lake City, Utah 84115

Subject: **Response to Request for Change in Condition for Variance to Technology-Based Phosphorus Effluent Limitations (TBPEL) UPDES Permit No. UT0021725**

Dear Ms. Briefer,

Part 12.d. of the 2018 Salt Lake City Permit variance for technology-based phosphorus effluent limits (SLC Variance for TBPEL) defines variance milestones including the submission of a City Council resolution supporting pursuit of a facility upgrade. SLC Public Utilities requested the due date for Part 12.d. be extended from May 1, 2019 to July 1, 2019 in a letter dated March 13, 2019 (DWQ-2019-002805). This request is based on the timing of the Salt Lake City Mayor's budget release date and City Council meetings. The request for extension is approved. The requirements of Part 12.d. are hereby altered to:

d. By no later than ~~May 1~~ July 1, 2019, SLC Public Utilities shall submit to DWQ:

i. A formal letter committing to the selected biological phosphorus removal technology (full BNR or the BNR facility operated as EBPR) including project schedule, and budget analysis (including project costs and funding information).

ii. A City Council resolution supporting the pursuit of the facility upgrade to the selected biological phosphorus removal technology. The resolution shall include the approximate budget for the facility upgrade.

iii. A proposed schedule of when completed design plans for permitting will be submitted to DWQ.

The submission of these 3 items by no later than July 1, 2019 will be considered in full compliance with Part 12.d. of the SLC Variance for TBPEL.

DWQ does not view this modification as a substantive change or a re-visitation of the variance as no rationale of the justification is being reevaluated. The final TBPEL compliance date remains the same; as such this due date alteration will not be public noticed.

Should you have any questions regarding this matter, please contact Mr. Ken Hoffman at (801) 536-4313 (kenhoffman@utah.gov) of my staff.

Sincerely,

Erica B Gaddis

Erica Brown Gaddis, PhD
Director

EBG/KH/blj

DWQ-2019-002804

JACQUELINE M. BISKUPSKI
Mayor

DEPARTMENT OF PUBLIC UTILITIES

March 13, 2019

Utah Department of Environmental Quality
Division of Water Quality
PO Box 144870
Salt Lake City, UT 84114—4870

Attention: Erica Gaddis, Director

Request for Change in Condition for Variance to Technology-Based Phosphorus Effluent Limitations (TBPEL); UPDES Permit No. UT0021725

Dear Director Gaddis:

On May 29, 2018, Utah Department of Environmental Quality (UDEQ) transmitted its approval of a variance to the TBPEL permit variance issued for Salt Lake City Department of Public Utilities (SLCDPU) (UPDES Permit No. UT0021725). One condition of the variance states that by May 1, 2019, *"Salt Lake City must submit a City Council resolution supporting the pursuit of the facility upgrade to the selected biological phosphorus removal technology. The resolution shall include the approximate budget for the facility upgrade."*

As we have been preparing materials for our City Council to consider along with this resolution, we realized that in order to meet the May 1, 2019 deadline for the resolution, SLCDPU would need to request a City Council resolution approving the approximate budget for the facility reconstruction prior to the Mayor and Council's completion of the City's overall budget process for Fiscal Year (FY) 2020. This is especially relevant in that portions of SLCDPU's proposed FY 2020 budget include revenue bonding and design costs associated with the facility reconstruction.

Since our FY 2020 budget year begins on July 1, 2019, and our City Council generally approves the City's overall budget in June, we are requesting that that we provide your office with the required City Council resolution by July 1, 2019. This condition change will be in better alignment with the sequence of Salt Lake City's municipal budgeting process.

Thank you for taking the time to consider this request. SLCDPU is committed to the reconstruction and upgrade of our Water Reclamation Facility and meeting the January 1, 2025 TBPEL compliance date. Please do not hesitate to contact me with any questions or concerns at 801.483.6741, or laura.briefer@slcgov.com.

Sincerely,

Laura Briefer
Director

cc: Jesse Stewart, Deputy Director
Rusty Vetter, SLC Attorney's Office

State of Utah
GARY R. HERBERT
Governor
SPENCER J. COX
Lieutenant Governor

Department of
Environmental Quality
Alan Matheson
Executive Director
DIVISION OF WATER QUALITY
Erica Brown Gaddis, Ph.D.
Director

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JUN 05 2018

May 29, 2018

Laura Briefer
Director of Department of Public Utilities
Salt Lake City Corporation
1530 South West Temple
Salt Lake City, Utah 84115

Dear Ms. Briefer,

Subject: Approval of Variance to Technology-based Phosphorus Effluent Limitations (TBPEL) under R317-1-3.3.C.e.

We have completed our review of your "Technology-based Phosphorus Effluent Limits (TBPEL) Rule Compliance Postponement Request", that was submitted in regard to the Salt Lake City Department of Public Utilities (SLC Public Utilities) wastewater treatment plant. The request was submitted as a proposed demonstration of due diligence variance requirements of R317-1-3.3.C.e. The request was submitted by SLC Public Utilities, signed by Laura Briefer, and received on November 9, 2017 (DWQ-2017-011173). The request included documentation of the following items:

1. Salt Lake City Department of Public Utilities Projects at the SLCWRF: Nutrient Project Pre-Design Report, Waterworks Engineers (August, 2017).
2. Sewer Utility Capital Improvement Plan (CIP) Budget – Five Year Projected Budget 2018-2022. (by reference)
3. Clarification of Salt Lake City Department of Public Utilities application for a variance from R317-1-3.3, Technology-Based Limits for Controlling Phosphorus Pollution. (March 26, 2018)

These documents demonstrate that SLC Public Utilities is committed to, and diligently pursuing design, financing, and planning for construction of treatment works necessary to meet the TBPEL. These documents further demonstrate that SLC Public Utilities will be unable to complete facilities improvements necessary to comply with the TBPEL by the January 1, 2020 deadline. As

a result, the attached permit variance to the TBPEL under R317-1-3.3.C.e is hereby issued subject to the following conditions:

1. SLC Public Utilities shall comply with the requirements of the attached Permit Variance for Technology-Based Phosphorus Effluent Limits.

2. Nothing in this concept approval letter relieves SLC Public Utilities from compliance with their current UPDES permit requirements.

Should you have any questions, please contact either Ken Hoffman at (801) 536-4313 (kenhoffman@utah.gov) or Jeff Studenka at (801) 536-4395 (jstudenka@utah.gov) of my staff.

Sincerely,

Erica B. Gaddis

Erica Brown Gaddis, PhD
Director

EBG/KH/JS/blj

Enclosure (1): 1. Permit Variance for Technology-Based Phosphorus Effluent Limits (DWQ-2018-003574)

DWQ-2018-003572

UTAH DIVISION OF WATER QUALITY

IN THE MATTER OF Salt Lake City Department of Public Works 1530 South West Temple Salt Lake City, Utah 84115 UPDES PERMIT NO. UT0021725	PERMIT VARIANCE FOR TECHNOLOGY-BASED PHOSPHORUS EFFLUENT LIMITS

BACKGROUND

1. Salt Lake City Department of Public Utilities' ("SLC Public Utilities") wastewater treatment plant in Salt Lake City, Utah (the "Facility") provides wastewater services within Salt Lake County.

2. SLC Public Utilities' operations at the Facility are undertaken subject to UPDES Discharge Permit No. UT0021725 ("Permit").

3. The Facility is required to achieve technology-based phosphorus effluent limits ("TBPEL") on or before January 1, 2020, unless a variance is granted. *See* UAC R317-1-3.3.

4. SLC Public Utilities submitted a variance request, dated November 6, 2017 to the Utah Division of Water Quality ("DWQ"), seeking an extension of the TBPEL implementation date (the "Variance Request."). The Variance Request is based on the fact that SLC Public Utilities is in the process of designing and constructing improvements to the Facility to meet TBPEL requirements, however such improvements cannot be completed prior to January 1, 2020, despite SLC Public Utilities' diligence.

5. SLC Public Utilities submitted a clarification to their variance request, dated March 26, 2018 to the DWQ. This clarification formally replied to items of question by DWQ concerning their variance request and potential milestones for variance approval.

6. Utah law provides that DWQ may grant a variance as to the implementation date for compliance with the TBPEL in the event that the operator demonstrates due diligence toward construction of a treatment facility designed to meet TBPEL, provided that such compliance date shall not be later than January 1, 2025. *See* UAC R317-1-3.3.C.e.

7. The Director of DWQ has determined that SLC Public Utilities has met its burden to show diligence within the meaning of the UAC R317-1-3.3 and that a variance is appropriate, subject to the limitations and conditions provided herein.

AUTHORITY

8. The Director of DWQ has authority to grant a variance as to the implementation deadline for TBPEL pursuant to UAC R317-1-3.3 and the corresponding provisions of the Utah Water Quality Act.

9. The State of Utah administers the Utah Pollution Discharge Elimination System (UPDES) permit program under the Utah Water Quality Act.

DUE DILIGENCE - FINDINGS

10. The Variance Request included the following submissions, among others:

a. Salt Lake City Department of Public Utilities Projects at the SLCWRF: Nutrient Project Pre-Design Report, Waterworks Engineers (August, 2017).

b. Sewer Utility Capital Improvement Plan (CIP) Budget – Five Year Projected Budget 2018-2022. (by reference)

c. Clarification of Salt Lake City Department of Public Utilities application for a variance from R317-1-3.3, Technology-Based Limits for Controlling Phosphorus Pollution. (March 26, 2018)

11. Based on the foregoing submissions, the Director has determined that SLC Public Utilities has established due diligence toward construction of Biological Phosphorus Removal treatment facility upgrade designed to meet TBPEL, within the meaning of UAC R317-1-3.3.C.e.

VARIANCE

12. The Director hereby grants SLC Public Utilities a variance as to the compliance date to achieve TBPEL, until the time that its facility improvements described in the Variance Request are operational; subject to the following conditions:

a. This variance does not extend beyond January 1, 2025. SLC Public Utilities must comply with all TBPEL requirements by that date.

b. Pursuant to UAC R317-1-3.3.C.2, this variance is subject to re-evaluation in the event that there is any substantive change in the facility design or construction plans provided in the Variance Request. SLC Public Utilities must provide timely notice to DWQ of any such substantive changes.

c. By no later than January 31, 2022, SLC Public Utilities shall submit to DWQ an approvable complete construction permit application per UAC R317-3 for construction permitting of a facility to biologically remove phosphorus to 1.0 mg/L or less.

d. By no later than May 1, 2019, SLC Public Utilities shall submit to DWQ:

   i. A formal letter committing to the selected biological phosphorus removal technology (full BNR or the BNR facility operated as EBPR) including project schedule, and budget analysis (including project costs and funding information).

   ii. A City Council resolution supporting the pursuit of the facility upgrade to the selected biological phosphorus removal technology. The resolution shall include the approximate budget for the facility upgrade.

   iii. A proposed schedule of when completed design plans for permitting will be submitted to DWQ.

e. Beginning no later than July 1, 2019, and for every year thereafter while this variance is in effect, SLC Public Utilities agrees to submit to DWQ an annual report relating to its phosphorus discharges (the "Annual Report"). The scope of the Annual Report shall include descriptions of all projects and work necessary, in reasonable detail, to achieve compliance with the TBPEL rule. The Annual Report will provide a summary of progress and milestones achieved in all construction, study, funding, planning, and design projects during the previous reporting period, projected progress and milestones scheduled to be completed during the following reporting period, and if the project(s) are on schedule. The Annual Report will also provide information on effluent phosphorus concentrations to determine SLC Public Utilities' compliance with Parts 11.e. and 11.f. of this variance, noted below.

   i. The Annual Report must specifically state the economic benefit per year SLC Public Utilities will receive from January 1 to December 31 of the coming year from this due diligence variance for not treating total phosphorus to 1.0 mg/L.

f. No total phosphorus effluent limitation will be added to the Permit before January 1, 2020.

g. Effective January 1, 2020, DWQ will impose the following interim effluent limitation under the Permit: total phosphorus annual average effluent limitation of 3.8 mg/L.

h. Upset Conditions from Part VI.H of UPDES Permit No. UT0021725

i. Effect of an upset. An upset constitutes an affirmative defense to an action brought for noncompliance with technology based permit effluent limitations if the requirements of paragraph 2 (ii) of this section are met. Director's administrative determination regarding a claim of upset cannot be judiciously challenged by the permittee until such time as an action is initiated for noncompliance.

ii. Conditions necessary for a demonstration of upset. A permittee who wishes to establish the affirmative defense of upset shall demonstrate, through properly signed, contemporaneous operating logs, or other relevant evidence that:

1. An upset occurred and that the permittee can identify the cause(s) of the upset;

2. The permitted facility was at the time being properly operated;

3. The permittee submitted notice of the upset as required under *Part V.H, Twenty-four Hour Notice of Noncompliance Reporting* of UPDES Permit No. UT0021725; and,

4. The permittee complied with any remedial measures required under *Part VI.D, Duty to Mitigate* of UPDES Permit No. UT0021725.

iii. Burden of proof. In any enforcement proceeding, the permittee seeking to establish the occurrence of an upset has the burden of proof.

Erica B. Gaddis

Date: 5/29/18

Erica Brown Gaddis, PhD
Director
Utah Division of Water Quality

DWQ-2018-003574

State of Utah
GARY R. HERBERT
Governor
SPENCER J. COX
Lieutenant Governor

Department of
Environmental Quality
Alan Matheson
Executive Director
DIVISION OF WATER QUALITY
Erica Brown Gaddis, PhD
Director

APR 17 2018

Newspaper Agency
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Salt Lake City, UT 84110

Email: naclegal@mediaoneutah.com
Account: 9001365712

ATTENTION: Legal Advertising Department

This letter will confirm authorization to publish the attached NOTICE in The Salt Lake Tribune or Deseret News in the first available edition. Please mail the invoice and affidavit of publication to:

Department of Environmental Quality
Division of Water Quality
Attn: Emily Canton
P.O. Box 144870
Salt Lake City, Utah 84114-4870

If there are any questions, please contact Savannah Miller at (801) 536-4316. Thank you for your assistance.

Sincerely,

[signature] for

Matthew Garn P.E., Manager
UPDES Surface Water Section

MG:JAS:smm

DWQ-2018-004188

State of Utah

GARY R. HERBERT
Governor

SPENCER J. COX
Lieutenant Governor

Department of
Environmental Quality

Alan Matheson
Executive Director

DIVISION OF WATER QUALITY
Erica Brown Gaddis, PhD
Director

April 18, 2018
DIVISION OF WATER QUALITY
UTAH DEPARTMENT OF ENVIRONMENTAL QUALITY
PUBLIC NOTICE OF VARIANCE TO TBPEL IMPLEMENTATION DATE

PURPOSE OF PUBLIC NOTICE

The purpose of this public notice is to declare the State of Utah's intention to grant a variance to the implementation deadline for Technology Based Phosphorus Effluent Limit (TBPEL) compliance to Salt Lake City Wastewater Treatment Facility. Pursuant to *UAC R317-1-3.3* and corresponding provisions of the Utah Water Quality Act.

PERMIT INFORMATION

PERMITTEE NAME:	Salt Lake City Water Reclamation Facility
MAILING ADDRESS:	1530 S West Temple, Salt Lake City, UT 84114
TELEPHONE NUMBER:	(801) 483-6670
FACILITY LOCATION:	1365 West 2300 North, Salt Lake City, UT 84116
UPDES PERMIT NO.:	UT0021725
RECEIVING WATERS:	Jordan River

BACKGROUND

The Salt Lake City Water Reclamation Facility (SLC) serves the greater Salt Lake City area, including the University of Utah. SLC submitted a variance request, dated November 6, 2017 to the Utah Division of Water Quality "DWQ", seeking a variance to the TBPEL implementation date. The Variance Request is based on the fact that SLC is in the process of designing and constructing improvements to the Facility to meet TBPEL requirements, however, such improvements cannot be completed prior to January 1, 2020, despite SLC's diligence.

PUBLIC COMMENTS

Public comments are invited any time prior to the deadline of the close of business on May 18, 2018. Written public comments can be submitted to: Jeff Studenka, UPDES Surface Water Section, Utah Division of Water Quality, P.O. Box 144870, Salt Lake City, Utah 84114-4870 or by email at: jstudenka@utah.gov. After considering public comment the Utah Division of Water Quality may execute the variance, revise it or abandon it. The variance is available for public review under https://deq.utah.gov/public-notices/water-quality-public-notices. If internet access is not available, a copy may be obtained by calling Jeff Studenka at 801-536-4395.

DWQ-2018-004186

JACQUELINE M. BISKUPSKI
Mayor

DEPARTMENT OF PUBLIC UTILITIES

March 26, 2018

Utah Department of Environmental Quality
Division of Water Quality
P.O. Box 144870
Salt Lake City, UT 84114-4870
Attn: Ken Hoffman, P.E.

Subject: Clarification of Salt Lake City Department of Public Utilities application for a variance from R317-1-3.3, Technology-Based Limits for Controlling Phosphorus Pollution

Dear Mr. Hoffman:

The intent of this letter is to provide the additional information requested in your e-mail communication dated February 23, 2018 related to the Salt Lake City Department of Public Utilities (City) application requesting a five-year variance (from January 1, 2020 to January 1, 2025) for compliance with the Technology-Based Phosphorous Effluent Limit (TBPEL) of 1.0 milligram per liter (mg/L) for the Salt Lake City Water Reclamation Facility (SLCWRF), UPDES Permit UT0021725.

Based upon your response, it is our understanding that we need to provide the following items to the Division of Water Quality (DWQ) as addendum to our variance request that was submitted to the DWQ on 11/06/2017 (see attached):

1. Planning/feasibility requirement
2. Schedule
3. Specified Technology and estimated budget
4. Milestone for submission of complete designs
5. Interim phosphorus limit

Each of these items is discussed in the subsequent paragraphs. Please let us know if you need additional information than what is provided.

1. Planning/Feasibility Requirement

Per your above referenced e-mail, it is our understanding that the previously submitted SLCWRF Nutrient Project Pre-Design Report meets the planning/feasibility requirement of the variance requests.

2. Schedule

The City is selecting an engineering consulting firm to provide professional design and construction management services for the duration of our project. The selection is expected to be finalized by May 2018. The project schedule and design concept is anticipated to be finalized by May of 2019. We will provide this information to DWQ for their review and comment.

WWW.SLCGOV.COM
TEL 801-483-6900 FAX 801-483-6818

3. Specified Technology and Estimated Budget
The City is planning to design and construct facilities to provide full biological nutrient removal (BNR). The City plans to design the facilities in such a way that it can be operated to provide either enhanced biological phosphorus removal (EBPR) or full BNR. The specific process design for these facilities (e.g., MLE, Westbank) will be finalized with the selected design firm. We anticipate the design concept will be finalized by May of 2019 and presented in the form of a design report for the entire facility.

The estimated budget for this project, based on the current 15% design, is \$325 - 510 million. Please note, this budget is based on the preliminary design, and will be updated and modified during final design concept development. As stated in our initial letter requesting a variance, we offer the following of our demonstrated financial commitment to this large capital project:

- The Five Year Projected Budget for fiscal years 2018-2022 includes planned expenditures for the current fiscal year and proposed budget for out years for the necessary capital projects at the plant. Attached are proposed expenditures for the fiscal year 2018/19 with projections through 2022.
- A capital financial plan has been prepared to include the design and construction of the new facility. The financial plan includes bonding completed in 2017 (\$78 million between collections and the SLCWRF) and additional planned bonding for more than \$300 million through fiscal year 2024 for final design and construction of the facility. The projected bonding amounts may change pending refined overall project costs.
- Beginning in fiscal year 2016, the City implemented the first of several planned rate increases to raise revenue for the WRF project and account for bonding debt service. The rate increases approved by the Salt Lake City Council in fiscal years 2016, 2017, and 2018 were 8%, 12%, and 30% increases, respectively. We have presented our plan for anticipated rate increases for fiscal years 2019, 2020, 2021, and 2023 at 15%, 15%, 10%, and 8%, respectively. The projected rate increases may change pending refined project costs and bonding amounts and schedules. The Salt Lake City Mayor and Council understand the need for the SLCWRF project, and are aware of the projected rate increases and financing plan.
- The City has communicated with DWQ regarding potential funding sources through the State Revolving Fund Loan; however, additional discussion with the City's financial advisors, and with DWQ will be conducted before determining the best course of action.

4. Milestone for Submission of Complete Design
It is anticipated that this project will need to be delivered in several construction packages in order to be completed to meet the requested January 1, 2025 deadline. We would like to work with DWQ to optimize the submittal and review of these packages to ensure a complete and well-reviewed design prior to beginning construction. By May 2019, we plan to have finalized the conceptual design of the facility, which would include a design report for the entire facility, a project schedule, and a list of design/construction packages. We will work with DWQ prior to finalizing this schedule and package delivery list to plan appropriate time for submittal review and to ensure DWQ is in agreement with the review plan moving forward. In addition, we have discussed with DWQ having semi-annual project update meetings with the City, our design engineers, and DWQ staff.

5. Interim Phosphorus Limit
DWQ may propose a draft interim phosphorous effluent limit of 3.6 milligrams per liter (mg/L). This concentration is roughly equivalent to the SLCWRF effluent annual average. Although the SLCWRF is not currently specifically designed to treat phosphorous to low levels, the facility has typically removed approximately 30% of the influent phosphorous concentration. Our effluent

concentrations are directly tied to the influent phosphorous concentrations; therefore, we propose that no interim phosphorous limit is established. Rather, the SLCWRF will continue to operate with the goal of 30% reduction of influent phosphorous concentrations as our pre-treatment division continues to limit phosphorous influent concentrations.

Commitment

In summary, by May 1, 2019, the City shall submit to DWQ:

I. A formal letter committing to the selected biological phosphorus removal technology (full BNR or the BNR facility operated as EBPR) including project schedule, and budget analysis (including project costs and funding information).
II. A City Council resolution supporting the pursuit of the facility upgrade to the selected biological phosphorus removal technology. The resolution shall include the approximate budget for the facility upgrade.
III. A proposed schedule of when completed design plans for permitting will be submitted to DWQ.
IV. A commitment to operate the facility with the goal of 30% reduction of influent phosphorous concentrations while design and construction of the new SLCWRF is conducted.

In return, we request that DWQ will approve the proposed schedule and the submission of complete design plans in accordance with the approved schedule that is a requirement of this variance.

We thank you for your consideration of our application for variance and request that you contact us with any questions you may have.

Sincerely,
Jesse A. Stewart for

Laura Briefer
Director
Salt Lake City Corporation
Department of Public Utilities

cc: U.S. EPA, Region 8
Jesse Stewart, Jason Brown, Jamey West, Derek Velarde, Michelle Barry - SLCDPU
Patrick Leary, Chief of Staff, Salt Lake City Mayor's Office
Cindy Gust-Jensen, Director, Salt Lake City Council
File

Calfo, Janine

From:	Stewart, Jesse
Sent:	Monday, March 19, 2018 7:39 AM
To:	Briefer, Laura
Subject:	FW: TBPEL Variance request

This is to accompany the letter regarding the TBPEL Variance request.

Jesse

From: Ken Hoffman [mailto:kenhoffman@utah.gov]
Sent: Friday, February 23, 2018 5:01 PM
To: Stewart, Jesse <Jesse.Stewart@slcgov.com>
Subject: TBPEL Variance request

Good talking with you yesterday. You asked me to send an email to clarify potential variance milestones. The items we have asked for in a variance request has been planning/feasibility, schedule, and a governing body resolution for a project with specified technology and estimated budget. Your pre-design report covers your planning/feasibility requirement. However, it is a bit undefined on schedule and a selected technology.

In addition, to these items the draft variances approvals are including a milestone for submission of complete designs and an interim phosphorus limit. Your draft interim limit is proposed at 3.6 mg/L. This is intended as a keep doing what you're doing with no additional treatment then has occurred the past 2 years.

Milestones
Technology - on the phone you stated SLC will be going with the BNR project described in your report. So maybe you can wrap up the planning/feasibility piece with a brief letter.

Schedule - it sound like you would like to commit to supplying a schedule by the end of the year once you have your engineer on board.

Resolution - This probably again needs a little time to settle on the project, budget, timeline

Completed Plans - It seemed like you would like to include this as part of your schedule and have it determine the timeline for complete plans.

I've included some draft language at the bottom which could address each of these items.

Last, let me reiterate it is my goal to not create any new work for you but just track the good hard work you and Salt Lake City are already doing. Please let me know if you have thoughts as I'm happy to take feedback.

Thank you,
Ken
--

Ken Hoffman, P.E. | Environmental Engineer

Engineering Section

Phone: 801.536.4313

c. By no later than January 1, 2019, SLC Public Utilities shall submit to DWQ:

i. A formal letter committing to the selected biological phosphorus removal technology including project schedule and budget analysis including project costs and how the project will be funded.

ii. A resolution instructing SLC Public Utilities staff to pursue the facility upgrade to the selected biological phosphorus removal technology. The resolution shall include the approximate budget for the facility upgrade.

iii. A proposed schedule of when complete design plans for permitting will be submitted.

a) DWQ will approve the proposed schedule and the submission of complete design plans in accordance with the approved schedule will be a requirement of this variance.

State of Utah

GARY R. HERBERT
Governor

SPENCER J. COX
Lieutenant Governor

Department of
Environmental Quality

Alan Matheson
Executive Director

DIVISION OF WATER QUALITY
Erica Brown Gaddis, PhD
Director

RECEIVED

6 2 2018

PUBLIC UTILITIES

SCANNED
MAR 02 2018

FEB 27 2018

Laura Briefer, Director
Salt Lake City Water Reclamation Facility
1530 S West Temple
Salt Lake City, UT 84115

Dear Ms. Briefer:

Subject: UPDES Permit No. UT0021725, Salt Lake City Water Reclamation Facility, Review of Technology-Based Phosphorus Effluent Limits (TBPEL) Variance Request

The Division of Water Quality (DWQ) has received Salt Lake City Water Reclamation Facility's request for variance to the TBPEL rule (R317-1-3.3). Salt Lake City Water Reclamation Facility is requesting this variance of the condition found in R317-1-3.3.C.1.e, for due dilligence.

Ken Hoffman has been assigned to review the variance request for your facility. A fee will be assessed based on the amount of time needed to complete the review of the variance request. The fee schedule, as approved by the legislature, for Technical Review and assistance given is $90.00 per hour. It is estimated that the variance review will take between 12 and 40 hours, with an estimated cost between $1080.00 and $3600.00. Once the variance request is completed, an invoice will be sent to Salt Lake City Water Reclamation Facility.

If you have any questions regarding the variance review process, please contact Ken at kenhoffman@utah.gov or at (801) 536-4313. You may also contact Jeff Studenka at jstudenka@utah.gov or at (801) 536-4395 with questions about your UPDES permit.

Sincerely,

Erica B Gaddis

Erica Brown Gaddis, PhD
Director
EBG:MG:KH:JS:smm

JACQUELINE M. BISKUPSKI
Mayor

DEPARTMENT OF PUBLIC UTILITIES

November 6, 2017

Utah Department of Environmental Quality
Division of Water Quality
P.O. Box 144870
Salt Lake City, UT 84114-4870
Attn: Erica Gaddis, Director

Subject: Salt Lake City Department of Public Utilities application for a variance from R317-1-3.3, Technology-Based Limits for Controlling Phosphorus Pollution

Dear Director Gaddis:

The Salt Lake City Department of Public Utilities (SLC Public Utilities) is submitting this application requesting a five-year variance (from January 1, 2020 to January 1, 2025) for compliance with the Technology-Based Phosphorous Effluent Limit (TBPEL) of 1.0 milligram per liter (mg/L) for the Salt Lake City Water Reclamation Facility (SLC Water Reclamation Facility), UPDES Permit UT0021725. SLC Public Utilities has worked with professional environmental engineering firms and members of the research and academic community to identify appropriate fiscal and technological approaches to achieve the TBPEL, while also addressing other plant needs (e.g., replacement of aged facilities; addressing hydraulic, structural, and electrical insufficiencies; meeting sustainability objectives).

SLC Public Utilities has determined construction of a new facility capable of meeting the TBPEL is in the best interests of the public, environment, and SLC Public Utilities. Over the past two years, SLC Public Utilities has worked with consultants to prepare the pre-design for this Nutrient/Facility Upgrade project (see attached Nutrient Project Pre-Design Report).

Based on the magnitude of the project (e.g., the time required for design, and construction of the facility, and procurement of funds), SLC Public Utilities requests a five-year variance from the Utah Department of Environmental Quality (UDEQ) Division of Water Quality (DWQ) for compliance with the TBPEL. This request for a variance is per Utah Administrative Code R317-1-3.3.C.1e, which states,

> "Where the owner of a non-lagoon discharging treatment works demonstrates due diligence toward construction of a treatment facility designed to meet the TBPEL, the compliance date shall be no later than January 1, 2025."

SLC Public Utilities offers as demonstration of our due diligence, the following:

- **Nutrient Project Pre-Design Report (2017)** - This Nutrient Project Pre-Design Report (attached) provides the basis of design and pre-design for facility upgrades. In addition, SLC Public Utilities has developed and posted a Request for Qualifications (RFQ) with the

Request for Proposal (RFP) for the design and construction of the facility in local newspapers and on the SciQuest website: https://solutions.sciquest.com/apps/Router/SupplierLogin?CustOrg=StateOfUtah.

- **Sewer Utility Capital Improvement Plan (CIP) Budget – Five Year Projected Budget 2018-2022** –SLC Public Utilities' 2017/2018 Annual Budget includes planned expenditures for the current fiscal year and proposed budget for out years for the necessary capital projects at the plant. In addition, SLC Public Utilities has developed a capital financial plan to include the design and construction of the new facility. The financial plan includes bonding completed in 2017 and additional planned bonding in the next two to seven years for design and construction of the facility. In addition, SLC Public Utilities has communicated with the DWQ regarding potential funding sources through the State. The budget and process has been reviewed and adopted by the Public Utilities Advisory Committee (PUAC)[1] and Mayor of Salt Lake City as well as the Salt Lake City Council.

We thank you for your consideration of our application for variance and request that you contact us with any questions you may have.

Sincerely,

Laura Briefer
Director
Salt Lake City Corporation
Department of Public Utilities

cc: U.S. EPA, Region 8
Jesse A. Stewart, Jason Brown, Dale Christensen – SLCDPU
Patrick Leary, Salt Lake City
File

Attachments:
- Nutrient Project Pre-Design Report

[1] "The Salt Lake City Public Utilities Advisory Committee annually reviews the department's operation and maintenance budget and expenditures, examines the department's water and sewer system capital improvements program, recommends proposed legislation relating to water and sewer, and consults with the Mayor concerning water resources and sewage reclamation requirements. This committee assists the Public Utilities Director as much as possible to continue orderly development and operation of the public utilities system for the city." (http://www.slcgov.com/bc/boards-and-commissions-public-utilities-advisory-committee)

JACQUELINE M. BISKUPSKI
Mayor

DEPARTMENT OF
PUBLIC UTILITIES

CITY COUNCIL TRANSMITTAL

Patrick W Leary
Patrick Leary, Chief of Staff

Date Received: 4/5/2019
Date sent to Council: 4/9/2019

TO: Salt Lake City Council
Charlie Luke, Chair

DATE: April 5, 2019

FROM: Laura Briefer, MPA
Director, Department of Public Utilities

SUBJECT: Request for City Council adoption of new water and sewer rate structures pursuant to the recommendations of the 2018 Comprehensive Water, Sewer, and Stormwater Rate Study, and in coordination with approval of Public Utilities' approved Fiscal Year 2019-2020 Budget

STAFF CONTACTS: Lisa Tarufelli, Finance Administrator, lisa.tarufelli@slcgov.com

Laura Briefer and Lisa Tarufelli will address the Council on this resolution.

DOCUMENT TYPE: Ordinance (**Exhibit A**)

RECOMMENDATION: Approve an ordinance that would adopt the recommended new water and sewer rate structures, in coordination with approval of Public Utilities' proposed Fiscal Year 2019-2020 Budget.

BUDGET IMPACT:
The rate structure design is revenue neutral and does not impact Public Utilities' budget.

BACKGROUND/DISCUSSION:
Public Utilities completed a Comprehensive Water, Sewer, and Stormwater Rate Study (Rate Study) in 2018. The executive summary of the Rate Study is included in **Exhibit B**. Public Utilities' objectives are to retain defensible rate structures and fees, while meeting other important rate objectives, such as sufficient revenue, rate stability, conservation, and equity. For this Rate Study, Public Utilities contracted with Raftelis, a recognized expert in water rate setting, and used industry-standard utility cost of service methodology as reflected in the American Water Works Association *Manual of Water Supply Practices M1, Principles of Water Rates, Fees, and Charges* and in the *Water Environment Federation Manual of Practice No. 27, Financing and Charges for Wastewater Systems.*

1530 South West Temple
Salt Lake City, Utah 84115

WWW.SLCGOV.COM
Tel 801-483-6900 Fax 801-483-6818

Water Rates

Three substantive changes are recommended to the existing water rate structure to address key objectives of conservation, affordability, rate stability, demand management, and interclass equity. These include the following structural changes:

- Change the system-wide cost of service rate structure (where volume rates by block are the same for all customers) to a customer class cost of service volume rate structure. This results in different volume rates for residential, commercial, and industrial classes that reflect the specific cost to provide service to each class. The Rate Advisory Committee (RAC) established for the Rate Study, and the Public Utilities Advisory Committee (PUAC) felt this rate structure meets goals related to equity. It also reduces the allocation of costs to residential classes, which helps to address essential use affordability for the residential class.
- Reduce the block four threshold from 70 ccf (hundred cubic feet) to 60 ccf for residential, duplex and triplex customer classes. Reduce the commercial, institutional, and industrial customer class block four threshold from 700% of annual winter consumption (AWC) to 600% of AWC. This addresses both conservation and demand management priorities through stronger water pricing signals.
- Retain the fixed charge by meter size, but modify the price ratio between the meter sizes to reflect the capacity potential of each meter size relative to a ¾" meter. This addresses goals related to equity and helps promote residential essential use affordability.

A cost of service analysis was also completed to establish a new secondary water irrigation rate. This is due to the development of secondary water systems operated at certain Salt Lake City golf courses. Public Utilities does not operate a secondary water irrigation system, so secondary water irrigation rates had not been previously established. To help address conservation and demand management goals, the design of the secondary irrigation water rate structure includes the same inclining block volume rate structure as the culinary water irrigation meter rate.

Sewer Rates

The RAC and PUAC recommended reducing the minimum sewer charge from four units to two units. The reduction in the minimum charge has an essential use affordability benefit, and also incentivizes indoor water use efficiency. The RAC and PUAC recommended retaining the existing customer class volumetric rate structure by volume and strength of wastewater flow, which helps address interclass equity goals. Rates for each class increase due to the updated cost of service analysis, and the reduction of the minimum sewer charge.

PUBLIC PROCESS:

A major component of the Rate Study was public engagement through the formation of the RAC. The RAC included citizen representatives, environmental advocacy organizations, commercial and industrial representatives, low-income advocacy groups, and numerous City departments and divisions. The RAC's two overarching purposes were to represent and communicate community values and provide input, including recommendations to the PUAC, Salt Lake City Mayor, and Council. Over six meetings during fall and winter 2017, the RAC developed rate structure alternatives based on the following ranked pricing objectives:

1) Conservation
2) Essential Use Affordability
3) Demand Management

4) Rate Stability
5) Interclass Equity

To meet these objectives, the RAC recommended modifications to the water and sewer rate structures. The RAC provided their recommendations to the PUAC at the January 8, 2018 meeting. During the January 25, 2018 PUAC meeting, committee members finalized their recommendation to the administration. These recommendations are presented in the Rate Study. Public Utilities then presented the Rate Study's recommended structural changes to the water and sewer rates to the City Council during the October 2nd, 2018 work session.

EXHIBITS:

Exhibit A: Proposed Salt Lake City Ordinance Adopting New Water and Sewer Rate Structures

Exhibit B: Executive Summary of the Salt Lake City Department of Public Utilities Comprehensive Water, Sewer, and Stormwater Rate Study

Exhibit A

Proposed Salt Lake City Ordinance Adopting New Water and Sewer Rate Structures

SALT LAKE CITY ORDINANCE
No. of ____ 2019

(Adopting New
Water and Sewer Rate Structures)

WHEREAS, Salt Lake City Department of Public Utilities convened a Rate Advisory Committee comprised of community representatives and stakeholders, and completed a Comprehensive Water, Sewer, and Stormwater Rate Study in 2018;

WHEREAS, as part of the 2018 Rate Study, the Rate Advisory Committee and the Public Utilities Advisory Committee recommended changes in the structure of water and sewer rates to meet primary objectives of conservation, essential water use affordability, water demand management, rate stability, and interclass equity;

WHEREAS, the key structural changes reflecting the above objectives include: (1) changing water rates from a system-wide cost of service basis to a class cost of service basis to meet equity and essential water use affordability goals; (2) reduction of the block four threshold to meet conservation and demand management goals; and (3) reduction of the sewer minimum charge to meet essential water use affordability goals;

WHEREAS, a new rate for secondary irrigation water was established, including an inclining rate block structure, to facilitate the use and conservation of secondary irrigation water at certain Salt Lake City parks and golf courses

WHEREAS, the Salt Lake City Consolidated Fee Schedule is proposed to be amended to incorporate new water and sewer rate structures in coordination with approval of Public Utilities' Fiscal Year 2019-2020 budget; and

WHEREAS, the Salt Lake City Council finds that good grounds exist for updating the calculation of water and sewer rates to better reflect the policies and priorities of the Council and are necessary, reasonable, and equitable.

NOW, THEREFORE, be it ordained by the City Council of Salt Lake City, Utah:

SECTION 1. The Salt Lake City Consolidated Fee Schedule shall be amended, in pertinent part, to reflect changes to water and sewer rate structures in coordination with approval of Public Utilities' Fiscal Year 2019-2020 Budget.

SECTION 2. This ordinance shall become effective on the date of its first publication.

Passed by the City Council of Salt Lake City, Utah this __ day of ______, 2019.

____

CHAIRPERSON

ATTEST:

____

CITY RECORDER

Transmitted to Mayor on ______________________________.

Mayor's Action: _________ Approved. ____________ Vetoed.

____

MAYOR

____

CITY RECORDER

APPROVED AS TO FORM

Date: 4-5-19

By: ER Vetta

(SEAL)

Bill No. _______ of 2019.

Published: ___________________

HB_ATTY-#76899-v1-Water_&_Sewer_Rate_Changes_Ordinance_4-5-2019_

Exhibit B

Executive Summary of the Salt Lake City Department of Public Utilities
Comprehensive Water, Sewer, and Stormwater Rate Study

SALT LAKE CITY DEPARTMENT OF PUBLIC UTILITIES

Comprehensive Water, Sewer, and Stormwater Rate Study

Draft-Final Report / July 17, 2018

* Executive Summary and Secondary water rate summary

RAFTELIS

RAFTELIS

5619 DTC Parkway
Suite 850
Greenwood Village, CO 80111

Phone 303.305.1135

www.raftelis.com

July 16, 2018

Ms. Laura Briefer
Director of Public Utilities
Salt Lake City Department of Public Utilities
1530 South West Temple
Salt Lake City, UT 84115

Subject: Comprehensive Water, Sewer, and Stormwater Rate Study

Dear Ms. Briefer,

Raftelis is pleased to provide this 2018 Water, Sewer and Stormwater Rate Study to the Salt Lake City Department of Public Utilities.

The Report details the revenue requirement, cost of service, and rate design analysis used to develop proposed fiscal year 2019 water, sewer, and stormwater rates. This study also includes a review and update to the City's miscellaneous water, sewer, and stormwater fees. As part of this study, the City convened a Rate Advisory Committee (RAC). The RAC was charged with reviewing and providing recommendations to Staff and the Public Utilities Advisory Board (PUAC) on water and sewer rate structure alternatives. The RAC's final recommendations are discussed in this report along with the PUAC recommendation to City Council.

We would like to thank you, Mr. Brad Stewart, Mr. Kurt Spjute and the members of the RAC for their assistance and support during this study. Questions regarding this report and the Study should be direct to Mr. Cristiano or me at the contact information below.

Sincerely,
RAFTELIS, INC.

Richard D. Giardina   Todd Cristiano

Rick Giardina
Executive Vice President
rgiardina@raftelis.com
303-305-1136

Todd Cristiano
Manager
tcristiano@raftelis.com
303-305-1138

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LIST OF APPENDICES

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1. EXECUTIVE SUMMARY

1.1 Introduction

The Salt Lake City Department of Public Utilities (Department) retained Raftelis to conduct a water, sewer, stormwater rate and miscellaneous fees study. This study included the following:

- Engaging a Rate Advisory Committee (RAC) to provide input and feedback on water and sewer rate structure alternatives to the PUAC.
- Development of revenue requirements for the water, sewer and stormwater utilities for fiscal year (FY)19[1,2].
- Analysis of customer class cost of service for each utility.
- Design of cost-of-service rates and rate alternatives as recommended by the Rate Advisory Committee for FY19.
- Review and update the Department's miscellaneous fees for the water, sewer and stormwater utilities.

Raftelis applied industry standard methodologies supported by the American Water Works Association (AWWA) *Principles of Water, Rates, Fees, and Charges* M1 manual and the Water Environment Federation *Financing and Charges for Wastewater Systems Manual of Practice, No. 27* in the development and design of utility rates.

1.2 Study Findings and Recommendations

1.2.1 Rate Advisory Committee

Department Staff assembled a Rate Advisory Committee to participate in a review of the Department's water and sewer rate structures. Raftelis along with The Langdon Group and Department Staff, facilitated six meetings with the RAC. These meetings included, among other topics, the identification and ranking of pricing objectives, RAC input on alternative rate structures, and the RAC's recommended rate structure for FY19 implementation designed to meet the identified goals and objectives. The results were presented to the Department's Public Utilities Advisory Committee (PUAC) on January 25, 2018 for their review and recommendation to the Mayor and City Council.

Appendix A contains the *2018 Rate Advisory Committee* report summarizing the water and sewer rate structure recommendations. The RAC developed rate alternatives based on the following ranked pricing objectives:

1. Conservation
2. Essential use affordability
3. Demand management
4. Rate stability

---

[1] FY19 is the period from July 1, 2018 through June 30, 2019.

[2] The term 'FY19 Utility Presented' shown in this report are the adopted FY18 rates for water, sewer, and stormwater multiplied by the FY19 proposed revenue adjustment for each utility.

5. Interclass equity
6. Intraclass equity

To meet these objectives, the RAC recommended the following modifications to the water and sewer rate structures:

Water Rate Structure Recommended Alternatives

- Retain the fixed charge by meter size. Modify the price ratio between the meter sizes to reflect capacity potential of each meter size to a ¾" meter. This fixed charge modification is recommended regardless of which volumetric rate alternative is selected.
- The RAC recommended two water volumetric rate structure alternatives using a class-based cost-of-service rate for consideration to the PUAC. Table 1.1 compares the existing rate structure and the alternative rate structures. ***Many alternatives were considered by the RAC. For purposes of this report, the original "names" of the alternatives, as considered by the RAC, have been retained.***

  - ***Alternative #2: COS/Existing Structure Adjusted for COS.*** Retain the fixed-block rate structure for all residential customers and the average winter consumption (AWC)-based rate structure for commercial, institutional and industrial (CII) customers.
    - Reduce the block 4 threshold from 70 hundred cubic feet (ccf) to 60 ccf for the single residence, duplex, and triplex customer classes.
    - Reduce the CII block 4 threshold from 700% of AWC to 600% of AWC.
  - ***Alternative #3: COS/AWC All*** Modify the existing fixed-block structure for single residence, duplex, and triplex to an AWC-based 4 block rate structure, the same structure as CII.
    - Set the single residence, duplex, and triplex customer class block 4 threshold at 600% of AWC.
    - Reduce the CII customer class block 4 threshold from 700% of AWC to 600% of AWC.

Table 1.1: Water – Current and Proposed Rate Structure Alternatives
City and County

	Residential[1]			CII[2]	
Block	**FY19 Utility Presented**	**Alt. #2 COS/Existing**	**Alt. #3 COS/AWC All**	**FY19 Utility Presented**	**Alt. #2/ Alt. #3**
Winter Period (Nov-Mar)	Block 1 Rate for All Usage			Block 1 Rate for All Usage	
Summer Rate Structure (April through November)					
Block 1	0-10 ccf	0-10 ccf	0-AWC[3]	0-AWC	0-AWC
Block 2	11-30 ccf	11-30 ccf	AWC-300%	AWC-300%	AWC-300%
Block 3	31-70 ccf	31-60 ccf	300%-600%	300%-700%	300%-600%
Block 4	>70 ccf	>60 ccf	>600%	>700%	>600%

(1) Single residence block 1: 0 to 10 ccf
Duplex block 1: 0 to 13 ccf
Triplex block 1: 0 to 16 ccf
(2) Alternative #2 and Alternative #3 CII rate structures are the same.
(3) AWC = Average Winter Consumption. "AWC – 300%" means usage greater than a customer's AWC and less than or equal to 300% of the customer's AWC.

Sewer Rate Structure Recommended Alternatives

- Retain the customer class volumetric rate structure by volume and strength of wastewater flow for each alternative. Strength categories include biochemical oxygen demand (BOD) and total suspended solids (TSS). The two alternatives recommended are:
  - ***Alternative #1: No Minimum Charge.*** Eliminate the minimum charge. Customers are only charged for their AWC monthly flow.
  - ***Alternative #3: Reduced Minimum Charge.*** Reduce the minimum charge allowance from 4 ccf to 2 ccf. This reduces the minimum charge by approximately 43 .

Table 1.2 shows the existing sewer rate structure. The proposed structure remains unchanged from the existing.

Table 1.2: Sewer – FY19 Utility Presented and FY19 Proposed Raftelis Rate Structure

Class(1)	BOD Strength mg/l	TSS Strength mg/l	Flow $ per ccf	BOD $ per ccf	TSS $ per ccf
1	0 - 300	0 - 300	Applies to Existing and All Alternatives		
2	300 - 600	300 - 600	Same volume rate for all classes	Volume rate varies by BOD strength	Volume rate varies by TSS strength
3	600 - 900	600 - 900			
4	900 - 1,200	900 - 1,200			
5	1,200 - 1,500	1,200 - 1,500			
6	1,500 - 1,800	1,500 - 1,800			
7	>1,800	>1,800	*Special Rate by Customer*		

(1) Customers in classes 1 through 6 are billed monthly based on their average winter consumption (AWC) times the sum of the rates for flow, BOD, and TSS rates or a minimum charge whichever is greater. AWC is the average of water usage for the months November through March.

1.2.2 Public Utilities Advisory Committee

Staff presented the water and sewer alternatives at the PUAC's January 25, 2018 meeting. The PUAC recommended the following:

- Water:
  - Monthly fixed charge: Varies by meter size; capital costs by meter size varies by on meter capacity ratios.
  - Volume rate structure: Alternative #2: COS/Existing Structure Adjusted for COS
- Sewer: Alternative #3: Reduced Minimum Charge

The remainder of this report will show the proposed water and sewer rates under these alternatives. The term "proposed rates" refers to rates based on the recommended rate structure alternatives from the PUAC.

1.2.3 Water Rate Study

FY19 Proposed Raftelis water rates for were developed based on the following:

- A system-wide 4% revenue increase over FY18
- Customer class cost-of-service analysis
- Rate structure recommendations from the RAC and final recommendations from the PUAC

Fixed Charge

The proposed fixed charge varies by meter size. The fixed charge recovers the following costs: meter reading/billing, customer service, and a portion of capital costs. Meter reading, billing and customer service costs do not vary by meter size. Capital costs increase as meter size increases recognizing the additional costs to serve larger capacity customers. The capital cost differential by

meter size is based on the ratio of the maximum allowable flow capacity to a ¾" meter. Table 1.3 shows the FY19 Utility Presented and FY19 Proposed Raftelis fixed charges.

Table 1.3: Water – FY19 Utility Presented and FY19 Proposed Raftelis Fixed Charges(1)

Meter Size	FY19 Utility Presented	FY19 Proposed Raftelis	Change - $	Change - %
3/4"	$9.89	$8.84	($1.05)	(11%)
1"	9.89	11.56	1.67	17%
1 ½"	11.68	18.37	6.69	57%
2"	12.68	26.55	13.87	109%
3"	21.28	48.34	27.06	127%
4"	22.78	72.86	50.08	220%
6"	32.88	140.98	108.10	329%
8"	59.11	222.71	163.60	277%
10"	109.63	576.91	467.28	426%

(1) County fixed charges are 1.35 times City fixed charges.

Volume Rates

The proposed volume structures for residential and commercial (CII) retains the 4-block inclining structure. The irrigation volume structure retains the 3-block inclining structure. The residential rate structure is a fixed block structure while the commercial or CII class is an individualized structure. Residential rates include single residence, duplex, and triplex classes. CII includes commercial, industrial, and institutional customers. The CII structure's thresholds are based on each customer's average winter consumption (AWC). The irrigation structure retains the individualized target budget-based structure. The volume rates developed in this study are based on each class' cost of service. Table 1.4 shows the FY19 Utility Presented and FY19 Proposed Raftelis rates.

Table 1.4: Water – FY19 Utility Presented and FY19 Proposed Raftelis Residential Volume Rates(1) City Customers

Block	FY19 Utility Presented $ per ccf	FY19 Proposed Raftelis $ per ccf	Change - $	Change - %
RESIDENTIAL(2)				
		Winter (November - April)		
All Usage	$1.35	$1.30	($0.05)	(3.7%)
		Summer (April - October)		
1	$1.35	$1.30	($0.05)	(3.7%)
2	1.85	1.78	(0.07)	(3.8%)
3	2.57	2.47	(0.10)	(3.9%)
4	2.74	2.63	(0.11)	(4.0%)
COMMERCIAL				
		Winter (November - April)		
All Usage	$1.35	$1.42	$0.07	5.2%
		Summer (April - October)		
1	$1.35	$1.42	$0.07	5.2%
2	1.85	1.94	0.09	4.9%
3	2.57	2.70	0.13	5.1%
4	2.74	2.87	0.13	4.7%
IRRIGATION				
		Winter (November - April)		
All Usage	1.85	1.71	($0.14)	(7.6%)
		Summer (April - October)		
1	$1.85	1.71	(0.14)	(7.6%)
2	2.57	2.38	(0.19)	(7.4%)
3	2.74	2.53	(0.21)	(7.7%)

(1) County rates are 1.35 times City rates

(2) Includes single residence, duplex, and triplex. See Table 1.1 for the block thresholds for each class.

1.2.4 Sewer Rate Study

FY19 Proposed Raftelis sewer rates were developed based on the following:

- A system-wide 15% revenue increase
- Customer class cost-of-service analysis
- Rate structure recommendations from the RAC and final recommendations from the PUAC

The FY19 Proposed Raftelis sewer structure and rates retain the customer class by sewer strength classification. The customer classes are assessed unit charges ($ per ccf) for flow, BOD, and TSS. Table 1.5 summarizes the FY19 Utility Presented and FY19 Proposed Raftelis rate structure and rates.

Table 1.5: Sewer - Comparison of FY19 Utility Presented and FY19 Proposed Raftelis Rates

Class	BOD Strength mg/l	TSS Strength mg/l	FY19 Utility Presented(1)	FY19 Proposed Raftelis(2)	Change - $	Change - %
1	0 – 300	0 – 300	$3.05	$3.11	$0.06	2.0%
2	300 – 600	300 – 600	3.97	4.05	$0.08	2.0%
3	600 – 900	600 – 900	5.37	5.47	$0.10	1.9%
4	900 – 1,200	900 – 1,200	6.79	6.88	$0.09	1.3%
5	1,200 – 1,500	1,200 – 1,500	8.13	8.24	$0.11	1.4%
6	1,500 – 1,800	1,500 – 1,800	9.53	9.64	$0.11	1.2%
7	>1,800	>1,800	*Special Rate by Customer*			
Extra Strength Rates, $ per lb						
Chemical oxygen demand (COD)			$0.221	$0.356	$0.135	61.3%
Biochemical oxygen demand (BOD)			0.442	0.713	$0.271	61.3%
Total suspended solids (TSS)			0.264	0.451	$0.187	70.9%

(1) Customers in classes 1 through 6 are billed monthly based on their average winter consumption (AWC) times the sum of the flow rates for flow, BOD, and TSS or a minimum charge of $11.93 whichever is greater. AWC is the average of water usage for the months November through March.
(2) Customers in classes 1 through 6 are billed monthly based on their average winter consumption (AWC) times the sum of the flow rates for BOD, and TSS rates or a minimum charge of $6.82 whichever is greater. AWC is the average of water usage for the months November through March.

1.2.5 Stormwater Rate Study

Table 1.6 shows compares the FY19 Utility Presented and FY19 Proposed Raftelis stormwater fees. There is no change to the structure for FY19.

Table 1.6: Stormwater - Comparison of FY19 Utility Presented and FY19 Proposed Raftelis Rates

Customer Class	FY19 Utility Presented	FY19 Proposed Raftelis	Change $	Change %
1 or 2 Units < .25 acres	$4.94	$4.94	$0.00	0.0%
1 or 2 Units > .25	6.91	6.91	0.00	0.0%
3 or 4 Units	9.88	9.88	0.00	0.0%
Impervious Area Based	5.43	5.43	0.00	0.0%

1.2.6 Miscellaneous Fees Study

The Department assesses fees for various goods and services associated with providing water, sewer, and stormwater service. These goods and services directly benefit the customer requesting the service. As such, these costs are passed directly to the customer rather than through all rate payers. Raftelis reviewed selected fees from the water, sewer, and stormwater utilities, proposed updates and also evaluated new fees for the utilities. The existing and proposed fees can be found in Section 7 of this report. The fee categories reviewed include:

- Water connection fees
- Meter inspection and testing
- Fire hydrant maintenance fees
- Flat water charge – City and County Agencies
- Pressure testing
- Disconnection
- Plan review fees
- Sewer inspections/Industrial wastewater discharge permits
- Stormwater inspection fees
- Stormwater discharge permits

Table 3.12: Water – FY19 Typical Monthly Summer Bills - Single Residence City Customers

Usage ccf	FY19 Utility Presented	FY19 Proposed Raftelis	Change ($)	Change (%)	% of Summer Bills
0	$9.89	$8.84	($1.05)	(10.6%)	4.8%
5	16.64	15.34	(1.30)	(7.8%)	23.1%
10	23.39	21.84	(1.55)	(6.6%)	18.5%
20	41.89	39.64	(2.25)	(5.4%)	19.5%
30	60.39	57.44	(2.95)	(4.9%)	12.2%
40	86.09	82.14	(3.95)	(4.6%)	7.7%
50	111.79	106.84	(4.95)	(4.4%)	4.8%
60	137.49	131.54	(5.95)	(4.3%)	3.0%
70	163.19	157.84	(5.35)	(3.3%)	1.9%

3.12 Secondary Irrigation Water Rate

The Department requested a review and update of the secondary irrigation water rate for select golf courses and parks. This secondary water service is to the culinary irrigation water demands of select sites. The cost to provide this service includes an annual return on the Department's water resources cost and a water delivery cost.

The secondary irrigation water rate follows the same inclining block volume rate structure as the culinary irrigation-only meter rate. Each customer is provided a monthly budget based on the following factors: permeable area, historical evapotranspiration and standard watering practices. Water use within the budget is charged at a rate comparable to Block 2 of the standard residential rate (a block established to reflect reasonable outdoor use). Water use that exceeds the budget is charged in the higher blocks. It is hoped the structure provides incentive for wise use of water. Table 3.13 on the next page shows the summary calculation. Detailed calculations are contained in the appendix.

Table 3.13: Water - Secondary Irrigation Water Rate Calculation

Annual Costs	Units	Unit Cost $ per AF	Unit Cost $ per ccf
Annual return water resource costs	$5,194,331		
Reliable Water Supply, Acre-Feet (AF)	115,713		
Water resource unit cost, $ per AF		$44.89	$0.10335
Water delivery cost	$1,641,658		
Projected volume, AF	14,009		
Water delivery cost, $ per AF		$117.19	
Total, $ per AF		**$162.08**	**$0.37315**
Rate Structure, $ per AF			
Block 2		$162.08	37.3 cents
Block 3		307.95	71.4 cents
Block 4		623.01	$1.434

COUNCIL STAFF REPORT

CITY COUNCIL *of* SALT LAKE CITY

Item Schedule:
Briefing: 10/02/18
Public Hearing: n/a
Potential Action: n/a

TO: City Council Members

FROM: Sam Owen, Constituent Liaison / Policy Analyst

DATE: September 27, 2018

RE: Informational: Department of Public Utilities

2018 Comprehensive Water and Sewer Rate Study

GOAL OF THE BRIEFING

Provide information about the process and recommendations of the Comprehensive Water and Sewer Rate Study, especially with regard to changes that will impact customers. **A subsequent transmittal is expected to amend the City's Consolidated Fee Schedule (CFS) to include Rate Study recommendations and new rate structures.**

ISSUE AT-A-GLANCE

During the spring of 2017, the Department of Public Utilities indicated it would begin a public engagement process known as the Rate Advisory Committee (RAC) to solicit deliberate feedback on a number of proposed alternatives to the existing rate structure for water and sewer service. The Rate Study also involved an analysis of stormwater rates; no changes are currently recommended for this Utility. Public Utilities has a practice of conducting a rate study every five to six years.

The RAC met over the course of six meetings and forwarded recommendations to the Public Utilities Advisory Committee (PUAC), which forwarded its selections to the Administration. The Administration worked with financial consultants Raftelis to formalize these selections into a final report, which is the subject of this briefing. The RAC examined a number of alternatives and the present Rate Study models its recommendations from the alternatives that were selected by members of the RAC.

The final Raftelis report makes recommendations for changes to the rate structure for the City's water and sewer service. The final report also includes a number of recommendations for adjustments to existing miscellaneous

Public Utilities fees, as well as new miscellaneous fees, to be included as part of a subsequent proposal to amend the CFS.

Recommendations to the water and sewer rate structures would be revenue neutral, meaning the proposed changes would redistribute existing costs amongst the utilities' customer classes without generating additional funds compared to fiscal year 2019 adopted rates. Rate Study recommendations to miscellaneous fees would reflect actual costs of performing services related to the fees.

Changes to the rate structure in the Water Utility would result in slightly decreased bills for most residential customers, and increases in bills for commercial and industrial users, as well as institutional users. These changes would primarily impact water users connected through larger meter sizes and those consuming larger volumes of water. The changes in this rate structure are in part meant to reflect the essential use affordability priority identified by the RAC (Attachment 1, page 2). Because fixed charges for smaller meters would be reduced, along with reductions in charges for lower volumes of water use, essential water use would be anticipated to become more affordable with adoption of the recommended changes. Some institutional users will also be able to access and continue accessing secondary water for irrigation use which could result in savings; addition of the corresponding secondary water fee to the CFS would also increase transparency.

Changes to the rate structure in the Sewer Utility would result in similar impacts, with residential users experiencing some savings and more intensive users such as commercial and industrial customers experiencing bill increases. These adjustments in part reflect the costs of providing service to more intensive users of this utility. See ADDITIONAL & BACKGROUND INFORMATION for discussion.

No rate structure changes were recommended in the Stormwater Utility, the Street Lighting Utility was not included as part of the present study.

The water service rate differential for City and County customers is also addressed extensively by the Rate Study (See Attachment 1, PDF pages 33, 34 and 114; See also Attachment 2, County Water Rate Differential).

ATTACHMENTS

1. Administrative Transmittal: Comprehensive Water, Sewer and Stormwater Rate Study
2. Memorandum: County Water Rate Differential
3. RAC Stakeholder list

POLICY QUESTIONS

1. Based on the Raftelis Rate Study recommendations, rates would decrease slightly for some groups of users such as single residences, increase slightly for other groups, and increase significantly for still others.

    a. The Department performed extensive outreach over a period of several months to collect stakeholder feedback on various alternatives for new rate structures. Based on information gathered by the Department during this process, the Council may wish to ask, for which groups would the overall impacts of implementing the Rate Study recommendations be anticipated as the most noticeable or significant? Possible users experiencing significant impacts might include:

        i. Housing developers and residents, especially multi-family
        (as costs incurred through increased connection and service fees would likely be reflected in costs passed on to consumers)

        ii. Commercial developers and businesses utilizing new commercial space

iii. Industrial users, especially those with more treatment-intensive discharge, who would pay significantly more for both water service and sewer service

iv. Institutional users such as schools and churches, although impacts for these two customer classes would likely be primarily for water service rather than sewer as well.

b. Based on possible impacts to new construction such as multi-family housing and commercial properties, has the Department conducted outreach or otherwise looked into effects on the production of new supplies in these markets—i.e., if the rate structure and fees were implemented as recommended in the subject Rate Study, has the Department or have others explored likely impacts to the pace of new construction or housing values in Salt Lake City?

i. The Council may wish to explore this question in the context of new development—primarily commercial/industrial—slated for the City's Northwest Quadrant in coming years.

2. A recent proposal from the Administration seeks fee relief for developers of new multi-family housing when affordability requirements are met. How would that program affect the proposed changes, in terms of considering city-fees for developers as a package?

3. Miscellaneous fee recommendations: The Raftelis study includes recommended changes to the rate structures for sewer and water customers, as well as recommended changes to miscellaneous fees. New miscellaneous fees were studied and information provided based on the maximum cost of various services for which the miscellaneous fees are assessed, such as new connections, plan review and repeat inspections. The full cost of performing these services (enumerated in section 6 of the Raftelis report, Attachment 1 page 54) is not currently being offset by fee-for-service revenue, but is covered by other revenue sources (water sales and sewer charges).

   Adoption of the recommended changes to miscellaneous fees would not be revenue neutral, i.e. adopting the fee adjustments as outlined in the Raftelis report would result in new revenue and consideration of adjustments to the fiscal year 2019 adopted budget for Public Utilities. By contrast, the rate structure recommendations are revenue neutral for fiscal year 2019. Therefore, considering the miscellaneous fee recommendations at this time would have both budget and policy impacts.

a. The Council may wish to discuss whether recommended changes to miscellaneous fees and the resulting budget impacts, might be incorporated in a future budget discussion, such as with the fiscal year 2020 budget proposal for Public Utilities, when a holistic proposal could be prepared.

b. Furthermore, the Council may wish to allow more time to review and discuss the proposed fee increases separate from the rate structure proposal. This would allow time to understand the overall budget options, and to identify specific values with regard to the proposed increases and possible ramifications of adjustments.

i. The Council may wish to request that Public Utilities returns with a proposal of a preferred fee increase scenario based on the Raftelis findings.

ii. One purpose might also be to highlight how adopting new, increased fees could offset future rate increases for customers of the Utilities.

iii. The Council may wish to request that Public Utilities recommend miscellaneous fee increases that the Department would like to be considered in the shorter-term, as part of a possible CFS amendment to adopt the proposed rate structure changes. See KEY CHANGES—Miscellaneous Fees for discussion.

KEY CHANGES—Water Utility

Table 1.3: Water – FY19 Utility Presented and FY19 Proposed Raftelis Fixed Charges[1]

Meter Size	FY19 Utility Presented	FY19 Proposed Raftelis	Change - $	Change - %
3/4"	$9.89	$8.84	($1.05)	(11%)
1"	9.89	11.56	1.67	17%
1 ½"	11.68	18.37	6.69	57%
2"	12.68	26.55	13.87	109%
3"	21.28	48.34	27.06	127%
4"	22.78	72.86	50.08	220%
6"	32.88	140.98	108.10	329%
8"	59.11	222.71	163.60	277%
10"	109.63	576.91	467.28	426%
(1) County fixed charges are 1.35 times City fixed charges.				

Table 1.3 above shows monthly fixed charges assessed to customers based on the size of the water meter installed to provide water service. The Raftelis proposed changes to the fixed charges are shown in the highlighted column.

Fixed charges for water service help recover costs related to the Utility's basic capacity to provide service (e.g. costs of existing infrastructure such as reservoirs, pipes, pump stations and so on).

Most residential customers fall in the ¾ - inch and 1-inch meter sizes.

CONVERSION TABLE

Acre foot (AF)	Key definition Hundreds of cubic feet (ccf)	Gallons (g)
0.0022956841	**1**	**748**
1	**435.6**	**325,828.8**

Table 1.4: Water – FY19 Utility Presented and FY19 Proposed Raftelis Residential Volume Rates(1) City Customers

Block	FY19 Utility Presented $ per ccf	FY19 Proposed Raftelis $ per ccf	Change - $	Change - %
RESIDENTIAL(2)				
Winter (November – April)				
All Usage	$1.35	$1.30	($0.05)	(3.7%)
Summer (April – October)				
1	$1.35	$1.30	($0.05)	(3.7%)
2	1.85	1.78	(0.07)	(3.8%)
3	2.57	2.47	(0.10)	(3.9%)
4	2.74	2.63	(0.11)	(4.0%)
COMMERCIAL				
Winter (November – April)				
All Usage	$1.35	$1.42	$0.07	5.2%
Summer (April – October)				
1	$1.35	$1.42	$0.07	5.2%
2	1.85	1.94	0.09	4.9%
3	2.57	2.70	0.13	5.1%
4	2.74	2.87	0.13	4.7%
IRRIGATION				
Winter (November – April)				
All Usage	1.85	1.71	($0.14)	(7.6%)
Summer (April – October)				
1	$1.85	1.71	(0.14)	(7.6%)
2	2.57	2.38	(0.19)	(7.4%)
3	2.74	2.53	(0.21)	(7.7%)

(1) County rates are 1.35 times City rates

(2) Includes single residence, duplex, and triplex. See Table 1.1 for the block thresholds for each class.

Table 1.4 above shows volume rates in the form of cost per "ccf," or cost per one hundred cubic feet. One ccf equals approximately 748 gallons. The Raftelis proposed changes would result in lower rates for residential users. The amount decrease in residential water rates is close to the amount the rates were increased in the fiscal year 2019 adopted City budget. Rates for irrigation users would also decrease, and rates for commercial users would increase. See ADDITIONAL AND BACKGROUND INFORMATION for discussion on the redistribution of costs that could be said to have differential impacts on user groups.

Table 3.9: Water – FY19 Utility Presented and Proposed Rate Structures

Block	Residential		CII		Irrigation[1]
	FY19 Utility Presented	FY19 Proposed Raftelis	FY19 Utility Presented	FY19 Proposed Raftelis	FY19 Utility Presented
Winter Period (Nov-Mar)	Block 1 Rate for All Usage		Block 1 Rate for All Usage		Block 1 Rate for All Usage
Summer Rate Structure (April through November)					
Block 1[2]	0-10 ccf	0-10 ccf	0-AWC[3]	0-AWC	0 – Target Budget
Block 2	11-30 ccf	11-30 ccf	AWC-300%	AWC-300%	Target Budget – 300% of Budget
Block 3	31-70 ccf	31-60 ccf	300%-700%	300%-600%	>300% of Target Budget
Block 4	>70 ccf	>60 ccf	>700%	>600%	

(1) No changes to the irrigation rate structure.

(2) Single residence block 1: 0 to 10 ccf

Duplex block 1: 0 to 13 ccf

Triplex Block 1: 0 to 16 ccf

(3) AWC = Average Winter Consumption. "AWC – 300%" means usage greater than a customer's AWC and less than or equal to 300% of the customer's AWC.

Table 3.9 above outlines Raftelis proposed changes to water volume structures. The only recommended change to this aspect of the water rate structure is lowering the threshold at which Block 4 "kicks in." This change would mean that each respective user's highest rate would become active at a lower level of use. Such an adjustment in how rates are assessed can promote conservation.

Table 3.12: Water – FY19 Typical Monthly Summer Bills - Single Residence City Customers

Usage ccf	FY19 Utility Presented	FY19 Proposed Raftelis	Change ($)	Change (%)	% of Summer Bills
0	$9.89	$8.84	($1.05)	(10.6%)	4.8%
5	16.64	15.34	(1.30)	(7.8%)	23.1%
10	23.39	21.84	(1.55)	(6.6%)	18.5%
20	41.89	39.64	(2.25)	(5.4%)	19.5%
30	60.39	57.44	(2.95)	(4.9%)	12.2%
40	86.09	82.14	(3.95)	(4.6%)	7.7%
50	111.79	106.84	(4.95)	(4.4%)	4.8%
60	137.49	131.54	(5.95)	(4.3%)	3.0%
70	163.19	157.84	(5.35)	(3.3%)	1.9%

Table 3.12 above outlines how Raftelis proposed changes to the rate structure would impact non-commercial residential water bills.

- 65.9% of these bills would be estimated to come in between about 5% and 10% percent lower with the proposed changes.
- 27.9% of these bills would be estimated to receive a reduction approximately equal to the last two years of water rate increases.

Table 3.13: Water - Secondary Irrigation Water Rate Calculation

Annual Costs	Units	Unit Cost $ per AF	Unit Cost $ per ccf
Annual return water resource costs	$5,194,331		
Reliable Water Supply, Acre-Feet (AF)	115,713		
Water resource unit cost, $ per AF		$44.89	$0.10335
Water delivery cost	$1,641,658		
Projected volume, AF	14,009		
Water delivery cost, $ per AF		$117.19	
Total, $ per AF		**$162.08**	**$0.37315**
Rate Structure, $ per AF			
Block 2		$162.08	37.3 cents
Block 3		307.95	71.4 cents
Block 4		623.01	$1.434

1 acre-foot (AF) equals 435.6 hundreds of cubic feet (ccf) and 325,828.8 gallons

Table 3.13 above outlines a new secondary irrigation water rate. Irrigation rates are assessed on the basis of a "target budget" for irrigation water use that is formulated using factors like the customer's permeable area,

historical evapotranspiration and standard watering practices. Water use that exceeds the budget is charged in higher blocks, just like water use for non-irrigation customers.

KEY CHANGES—Sewer Utility

Table 4.11: Sewer - Typical Monthly Bill Comparison

AWC	FY19 Utility Presented	FY19 Proposed Raftelis	Change ($)	Change (%)
0	$11.93	$6.82	($5.11)	(42.8%)
1	11.93	6.82	(5.11)	(42.8%)
2	11.93	6.82	(5.11)	(42.8%)
3	11.93	9.33	(2.60)	(21.8%)
4	12.20	12.44	0.24	2.0%
5	15.25	15.55	0.30	2.0%
6	18.30	18.66	0.36	2.0%
7	21.35	21.77	0.42	2.0%
8	24.40	24.88	0.48	2.0%
9	27.45	27.99	0.54	2.0%
10	30.50	31.10	0.60	2.0%

Table 4.9: Sewer - FY19 Utility Presented Rates[1]

Class	BOD Strength mg/l	TSS Strength mg/l	Flow $ per ccf	BOD $ per ccf	TSS $ per ccf	Total $ per ccf
1	0 – 300	0 – 300	$1.87	$0.78	$0.40	$3.05
2	300 – 600	300 – 600	1.87	1.28	0.82	3.97
3	600 – 900	600 – 900	1.87	2.11	1.39	5.37
4	900 – 1,200	900 – 1,200	1.87	3.02	1.90	6.79
5	1,200 – 1,500	1,200 – 1,500	1.87	3.80	2.46	8.13
6	1,500 – 1,800	1,500 – 1,800	1.87	4.68	2.98	9.53
7	>1,800	>1,800	*Special Rate by Customer*			
Extra Strength Rates, $ per lb						
Chemical oxygen demand (COD)			$0.221			
Biochemical oxygen demand (BOD)			0.442			
Total suspended solids (TSS)			0.264			
(1) Customers billed based on the average water usage for the months November through March (AWC) or a minimum charge is $11.93, whichever is greater.						

Table 4.10: Sewer – FY19 Proposed Raftelis Rates(1)

Class	BOD Strength mg/l	TSS Strength mg/l	Flow $ per ccf	BOD $ per ccf	TSS $ per ccf	Total $ per ccf
1	0 – 300	0 – 300	$1.94	$0.68	$0.49	$3.11
2	300 – 600	300 – 600	1.94	1.11	1.00	4.05
3	600 – 900	600 – 900	1.94	1.83	1.70	5.47
4	900 – 1,200	900 – 1,200	1.94	2.62	2.32	6.88
5	1,200 – 1,500	1,200 – 1,500	1.94	3.29	3.01	8.24
6	1,500 – 1,800	1,500 – 1,800	1.94	4.05	3.65	9.64
7	>1,800	>1,800	*Special Rate by Customer*			
Extra Strength Rates, $ per lb						
Chemical oxygen demand (COD)			$0.280	$0.356		
Biochemical oxygen demand (BOD)			0.561	0.713		
Total suspended solids (TSS)			0.619	0.451		

(1) Customers in classes 1 through 6 are billed monthly based on their average winter consumption (AWC) times the sum of the rates for flow, BOD, and TSS or a minimum charge of $6.82 whichever is greater. AWC is the average of water usage for the months November through March.

Tables 4.11, 4.9 and 4.10 above show the difference between fiscal year 2019 adopted rates for sewer service and Raftelis proposed rates for sewer service.

- Table 4.11 is an example of the proposed decrease in the minimum fixed charge for sewer service, from $11.93/month to $6.82/month. This table shows typical monthly bills for discharge that is consistent with all single residential customers and many types of business such as offices. The bills escalate as the customer's average winter consumption (AWC) escalates. For customers with AWC costs lower than the fixed minimum charge, only this minimum charge is assessed. For customers with AWC costs higher than the fixed minimum charge, the minimum charge is not assessed in addition to costs based on the AWC—in other words, these customers are charged on the basis of AWC, without that AWC cost being layered on top of the minimum charge.

- Tables 4.9 and 4.10 show, respectively, fiscal year 2019 sewer rates based on strength of discharge and the Raftelis proposal for adjusting these rates.

  - Sewer rates are assessed on the basis of both flow volume and flow strength (flow strength is measured by the factors biological oxygen demand (BOD) and total dissolved solids (TSS)). These factors are ranked and then multiplied based on that ranking to determine costs for customers.

  - Cost per hundred cubic feet of flow increases with the Raftelis proposal, along with cost per hundred cubic feet of flow based on measurements of each BOD and TSS. The Raftelis proposal also includes cost increases for "Extra Strength Rates," and creates an additional set of factors by which these extra strength rates are assessed as well.

- Although some monthly bills would decrease based on the proposed decrease in the fixed minimum charge for sewer service, many monthly bills would increase based on the proposed adjustments that increase charges for flow, BOD and TSS. These increases in charges reflect cost of service and are revenue neutral based on the fiscal year 2019 adopted revenue figures.

KEY CHANGES—Miscellaneous Fees

The Raftelis findings involve recommendations for miscellaneous fee increases, intended to recoup the full cost of performing various services such as, and not limited to, those related to new connections, plan review and inspections. Costs for performing these services are currently not entirely offset by existing fees but are covered by other existing revenue sources.

If the recommended increases for miscellaneous fees were adopted en bloc as proposed in the Raftelis study, the result would not be revenue neutral. The Council may also wish for more detailed discussion with regard to the fee increases. As such, the Council may wish to request that Public Utilities include the recommendations for miscellaneous fees in its fiscal year 2020 budget proposal, perhaps broken down into one or more preferred scenarios. Doing so might also create the opportunity for ramifications of fee increases to be more fully explored, e.g. in terms of possible offsets to projected rate increases in coming years or in terms of impacts to the development and construction markets in coming years. These aspects of the study recommendations are also addressed in POLICY QUESTIONS.

As part of the current discussion and a possible subsequent amendment to the CFS, the Council may wish to consider Public Utilities' input on whether any fee increases would most need to be considered at this time. It has been indicated that one such recommendation is the suggested change to miscellaneous fees related to stormwater, outlined in table 6.8 below.

Some recommended changes might also entail offsets or balancing with regard to the General Fund. For example, changes related to fire hydrants and flat rates for water use would entail additional expenses for both the City Fire Department and the Unified Fire Authority. Other recommended changes might spur or compel other General Fund-related discussions such as those related to planning and permitting fees, and how costs for performing these services are or are not fully offset by corresponding charges.

Table 6.8: Stormwater Miscellaneous Fees

Fee Type	Existing Service Fee	Calculated Service Fee	Change $	Change %
Storm Water Inspection Fee	N/A	$132	132	New
Discharge into City Storm Water System – Includes 3 site visits	125	132	7	5.6%
Discharge into Stormwater System Re-inspection Fee	30	44	14	46.7%
Discharge into City Stormwater Registration Fee	20	44	24	120.0%

ADDITIONAL AND BACKGROUND INFORMATION

Service demand for the Utilities can be broken down into three main categories, also known as cost components: average day, maximum day and maximum hour.

- For every facility with the system used to provide service (sewer, water, stormwater, etc.), there is an underlying average demand, or uniform rate of usage, exerted on this facility based on what it takes to provide average, every day service for customers. This is the average day cost component.

- Certain facilities are operated and designed to meet the demand above the average day demand, i.e. to provide service for maximum day demand, which is extra-capacity or beyond just average. Costs associated with those facilities are allocated to both the average day and maximum day cost components.

- Similarly, other facilities are designed to meet demands in excess of maximum day requirements, known as maximum hour demand, or extra capacity designed to meet the systems' very highest and least frequent peaks of demand. Costs associated with these facilities are allocated to the average day, maximum day, and maximum hour cost components.

These types of service demand—average day, maximum day and maximum hour—constitute three of the five cost components to which attributes of the total system are allocated. The remaining two are meters & services and billing & collections. Costs are allocated differentially among users of the Water Utility based in part on how the facilities necessary to service the types of customers come into play.

For a simple example, heavy water users place demand on the system that necessitates the creation of facilities associated with meeting higher demand, such as storage and pumping infrastructure. Types of customers associated with heavier water use and thus higher demand on the system are also associated with the need for the infrastructure connected with meeting the higher demand they place on the system. In this way, costs are allocated among the classes of users such that costs of constructing, maintaining and operating infrastructure necessary to serve the respective classes are represented in the differential rates and fees to which various customers are subject.

Attachment 1, PDF page 93 provides one example of how these allocations are made on a percentage basis between five cost components for the Water Utility.

Similarly, allocations are also made among cost components of the Sewer Utility. These allocations correspond to costs assessed to sewer customers, again on the basis of connecting respective costs to provide service with charges assessed to respective classes of customers and the differential needs among the classes.

Attachment 1, PDF page 119 provides one example of how thse allocations are made on a percentage basis among the cost components for the Sewer Utility.

Similar connections between cost of service and charges assessed to recoup those costs underly the Raftelis proposed adjustments to the miscellaneous fees, as well.

Table 4.7: Sewer – FY19 Proposed Raftelis Customer Class Cost of Service

BOD Class	TSS Class	Flow, ccf	BOD	TSS	Bills	Total
1	1	$16,599,021	$5,783,469	$4,169,093	$1,098,589	$27,650,171
1	2	43,678	15,218	22,489	0	81,386
1	3	19,895	6,932	17,364	0	44,191
1	7	562	196	1,051	0	1,808
2	1	651,072	372,264	163,527	1,678	1,188,540
2	2	1,130,381	646,318	582,020	5,975	2,364,693
2	3	0	0	0	0	0
2	4	97,359	55,667	116,153	941	270,121
3	1	187,736	176,947	47,153	246	412,081
3	2	614,217	578,916	316,253	491	1,509,878
3	3	27,650	26,061	24,133	491	78,335
3	4	1,037	977	1,237	41	3,292
4	1	47,383	63,920	11,901	41	123,245
4	2	545,789	736,280	281,020	1,193	1,564,282
4	3	842	1,136	735	0	2,714
4	4	9,872	13,317	11,777	0	34,967
5	1	89,625	152,133	22,511	0	264,268
5	2	2,245	3,811	1,156	82	7,294
5	4	1,620	2,750	1,933	0	6,303
5	5	713	1,210	1,101	0	3,024
6	1	95,414	199,466	23,965	0	318,844
6	2	18,945	39,604	9,754	0	68,303
6	4	1,058	2,213	1,263	0	4,534
7	1	42,512	327,616	10,784	41	380,952
7	2	54,738	486,111	28,466	0	569,315
7	3	50,614	542,061	44,635	41	637,351
7	4	6,675	60,952	8,043	0	75,670
7	5	778	10,111	1,213	0	12,102
Total		**$20,341,431**	**$10,305,656**	**$5,920,730**	**$1,109,849**	**$37,677,666**

Table 4.7 exhibits the proportions between cost of service and the number of customers to whom sewer service would be provided. For example, discharge-intensive customers that rank BOD class 7 and TSS class 3 would account for only 41 bills, but $637,351 in total cost of service. By these figures, the average monthly cost of serving these discharge-intensive customers would be $15,545.15 each, compared to an average cost of $25.17 serving BOD class 1 and TSS class 1 customers (largely residential). The significantly higher average monthly cost of service for serving discharge-intensive customers would reflect the cost of volume and treatment capacity that must be in place to serve these customers.

SALT LAKE CITY DEPARTMENT OF PUBLIC UTILITIES
RENEWABLE ENERGY STUDY CONTRACT No.51360066

SALT LAKE CITY RENEWABLE ENERGY PLAN

Energy Strategies, Sunrise Engineering, Utah Clean Energy, Carollo Engineers
Consulting Team

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1.0 EXECUTIVE SUMMARY

The Salt Lake City Department of Public Utilities (DPU) is striving to reduce its reliance on electricity generated from fossil fuels as it provides essential services to its customers. To achieve these objectives, DPU seeks to diversify its energy portfolio through the development of renewable resources on Salt Lake City and DPU owned and managed properties, including solar photovoltaic (PV) systems, hydroelectric, cogeneration, wind power, and wastewater heat recovery systems. To support this goal, DPU selected a consultant team to conduct a renewable energy feasibility assessment and create this renewable energy plan. The projects described in this report offer DPU the opportunity to harness the sun, wind, and water to generate clean electricity. By exploring these renewable energy projects now, DPU will be prepared to adapt to future trends and needs and to improve its operations city-wide.

DPU selected a consultant team headed by Energy Strategies and including Sunrise Engineering, Utah Clean Energy, and Carollo Engineers, collectively referred to as the “Consultant Team,” to conduct the renewable energy feasibility assessment. The Consultant Team members have extensive experience helping private companies, institutions of higher education, and government agencies evaluate the technical, economic and regulatory feasibility of renewable energy and other clean energy technologies.

This study consisted of three sequential phases: a Preliminary Site Scoping Evaluation (Phase I), a Site-Specific Evaluation (Phase II), and a detailed evaluation of six potential project sites, including a regulatory assessment, an economic analysis, and recommendations for funding mechanisms and resources for each project (Phase III).

Phase I Preliminary Scoping Evaluation

DPU provided a list of 151 properties which were identified as potential sites for renewable energy projects. All 151 sites were screened and those found not to be suitable for a renewable energy project were eliminated. The remaining 42 sites were ranked using a screening matrix based on six criteria: suitability of the site for a renewable energy project, interconnection opportunities, zoning compatibility, permitting, and generation potential. Although not all 42 sites were ultimately reviewed in the Phase II analysis, many of these sites could support a viable renewable energy project. Combined, these sites could generate 18,779 megawatt-hours (MWh) of renewable energy.

Salt Lake City completed a 1 MW solar photovoltaic farm on a former landfill site at 1955 West 500 South in 2014. Existing incentives for solar, including a 30% federal tax credit which expires in 2016, can reduce the upfront expense of installing panels. DPU has the opportunity to install a solar farm more than three times the size of the landfill solar farm at the Terminal and Park Reservoirs.

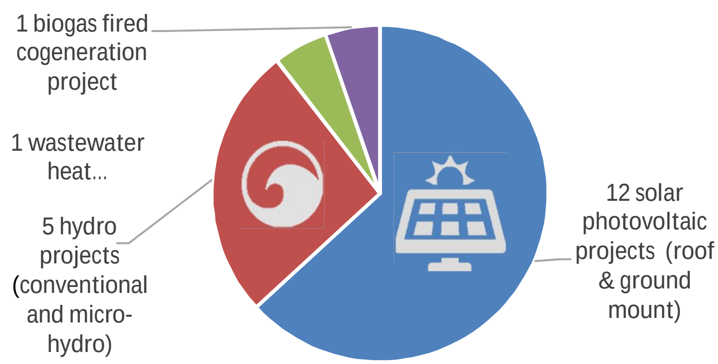
Phase II Site-Specific Evaluation

The results of the Phase I screening evaluation were presented to DPU for review and 19 sites were selected for more detailed evaluation in Phase II. These sites were chosen for further screening based on their score in Phase I screening matrix, because they provide opportunities for DPU to evaluate innovative technologies, or for both reasons. The 19 selected sites included:

- The 14 highest-scored sites from the Phase I analysis,
- 3 solar PV sites which received lower scores due to smaller generation potential but scored well in other categories,
- 2 projects that were not scored because further analysis was required: a wastewater heat recovery project at the West Temple trunkline and a cogeneration project at the Salt Lake City Water Reclamation Facility.

Combined, these projects could generate 13,690 megawatt hours of electricity, enough to offset approximately 44 percent of the electricity currently purchased by DPU from Rocky Mountain Power (RMP) and Murray City Power.

Figure 1-1. Projects Evaluated in Phase II



Conclusions and Recommendations of the Phase II Regulatory and Economic Analysis

From this group of 19 projects, DPU selected a representative cross-section of six projects to undergo a more detailed evaluation including regulatory assessment and economic analysis. A sixth project, wastewater heat recovery, was originally included in the Phase III detailed analysis. The wastewater heat recovery technology proved to be incompatible with the existing Central Heating Plant, so a demonstration project at the West Temple Trunkline was included in the analysis instead. The combined estimated overnight capital cost for the two solar photovoltaic (PV) and two hydroelectric projects is $14.8 million, and these four projects would be able to generate 6,287 MWh of electricity, and avoid 4,735 $MTCO_2e$ of greenhouse gas (GHG) emissions.

Table 1-1. Sites Included in Phase III Detailed Analysis

Site	Technology	Capacity (kW)	Benefit
Salt Lake City Water Reclamation Facility	Biogas Cogeneration	1,400	Use biogas to produce electricity; reduce the amount of biogas which is flared; offset purchases from RMP.
West Temple Trunkline	Wastewater Heat Recovery	N/A	Recover heat from wastewater; reduce natural gas consumption
15th East Reservoir[1]	Roof-mounted Solar PV	274	Produce electricity
Mountain Dell Dam	Hydroelectric	260	Produce electricity
Terminal & Park Reservoirs	Roof-mounted Solar PV	3,488	Produce electricity
Pressure Reducing Valve Station B11-R13	Hydroelectric Reverse-pump Turbine	190	Produce electricity

Regulatory Analysis:

The regulatory and financing assessment identified regulatory barriers and optimal rate schedules for each of the six Phase III sites in addition to various financing options available for each of the projects. While some of the rate options discussed are available now, others are currently under review by the Utah Public Service Commission (PSC). For those rates that are currently under review by the PSC, it is recommended that DPU continue to monitor the proceedings until new rates will be finalized.

A primary question asked regarding each potential site was whether electricity production from a renewable energy project at the site would exceed electricity usage at the site. Utah's net metering policy allows a facility to receive a credit for electricity produced on-site which can be used to offset purchases of electricity from the utility. However, electricity produced in excess of total annual usage is forfeited without compensation. If a renewable energy project produces more electricity than is

[1] Although a 274-kW solar installation was evaluated at the 15th East Reservoir, a smaller installation of approximately 25-kW could entirely offset electric usage on-site and potentially improve the economic viability of this project.

used on-site annually, the facility must contract to sell the excess electricity at wholesale rates or else forfeit it. Whether or not a facility is able to use the electricity on-site or must sell it obviously impacts the overall economics of the renewable energy project. Virtual net metering and selling excess electricity to the grid can help offset the capital investment in a renewable energy project.

While the Consultant Team recognizes it is DPU's preference to internally fund renewable energy projects using revenue from its utility operations, there are opportunities to leverage DPU's available funds with other funding sources to accelerate the deployment of City-owned renewable energy projects. All of the funding sources and financing mechanisms identified are viable options for lowering the upfront capital investment required by DPU. Moreover, from the perspective of DPU, lowering the capital investment will improve the economics of projects.

Economic Analysis:

Each project underwent an economic analysis which compared the projected cost of utility service at a given site to the potential savings DPU could capture by producing renewable energy. The economic value of each project was expressed as Net Present Value (NPV). First, each site was assessed using current regulatory and economic assumptions, including utility prices which are predicted to increase modestly over time. Next, two costs-of-carbon sensitivities were run to account for costs associated with future GHG regulations.[2] Assumed costs were \$25/MTCO_2e and \$50/MTCO_2e. Finally, one more sensitivity analysis was run assuming electricity generated by the pressure reducing valve project and the Terminal and Park Reservoirs solar PV project could be used to offset electricity consumed at other DPU facilities through virtual alternative net metering arrangement (which is not currently available in Utah). The results of the economic analysis are summarized in Table 1-2.

Summary and Conclusions

A detailed analysis of each of the six selected projects is provided in this report: table 9-1 provides an economic ranking of all six projects under several different regulatory scenarios, and table 9-2 ranks all six energy projects based on their potential to reduce DPU's greenhouse gas footprint. DPU must weigh several different factors when prioritizing amongst the projects presented in this report, including the economic analysis, the estimated avoided greenhouse gas emissions, the feasibility of each project, and other potential benefits of a project (such as increasing the visibility of Salt Lake City's energy initiatives). A summary of each project is provided below, including challenges associated with the project and recommendations for cost-effective completion, should DPU choose to pursue that project.

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[2] Federal agencies measure the potential impact of carbon emission regulations by assigning a cost to CO_2 emissions, represented as \$/megaton of carbon dioxide or carbon dioxide equivalent. This figure is used both to estimate the economic damages associated with an increase in carbon dioxide (CO_2) emissions and the value of a reduction in CO_2 emissions. The EPA has selected four Social Cost of Carbon values for use in regulatory analyses, representing various assumed discount rates. The most recent estimates for these values are available at http://www.epa.gov/climatechange/EPAactivities/economics/scc.html.

Table 1-2. Summary of Economic Analysis

Site	Technology	Rate Schedule	Overnight Capital Cost	Non-Fuel Operating Expense	Levelized Cost	Net Present Value compared to Cost of Utility Service ($Millions)		
			2014$ Millions	2014$ Millions	$ per MWh	$0 per $MTCO_2e$	$25 per $MTCO_2e$	$50 per $MTCO_2e$
Salt Lake City Water Reclamation Facility	Biogas Cogeneration (no BNR, no Nat. Gas)	Sch. 31 (9)	$0.00	$76.579	$25.60	($1.458)	($1.996)	($2.533)
	Biogas Cogeneration (BNR, Nat. Gas)	Sch.31 (9)	$0.00	$123.907	$61.50	$3.112	$3.468	$3.824
15th East Reservoir[3]	Roof-mounted Solar PV	Net metered	$0.920	$0.013	$153.50	$0.426	$0.314	$0.202
West Temple Trunkline	Wastewater Heat Recovery	N/A	$0.695	$0.000	N/A	$0.695	$0.584	$0.566
Mountain Dell Dam	Hydroelectric	Net metered	$1.551	$0.019	$92.00	$0.355	$0.064	($0.228)
Terminal & Park Reservoirs[3]	Roof-mounted Solar PV	Sch. 37	$11.292	$0.150	$139.50	$10.155	$8.699	$7.242
		Net metered			$139.50	$2.354	$0.898	($0.559)
Pressure Reducing Valve Station B11-R13	Hydroelectric Reverse-pump turbine	Sch. 37	$0.999	$0.015	$55.50	$0.585	$0.258	($0.068)
		Net metered			$55.50	($0.188)	($0.515)	($0.841)

Several projects rise to the top because they offer DPU attractive opportunities to reduce its environmental impact and the risk associated with carbon regulations while also lowering operations costs. If DPU were able to use electricity produced by one renewable energy project to offset electricity consumption at a different DPU site, either through virtual net metering or another, alternative net metering arrangement, savings associated with some projects would increase significantly. Although grants and financing mechanisms were not evaluated in the economic

[3] Costs and NPV are for a turnkey project without using a power purchase agreement (PPA) or other incentives. For solar PV projects, a PPA or prepaid lease structure would allow DPU to take advantage of a federal tax incentive through third-party ownership and could result in significant upfront cost reductions (up to 30percent). A PPA can be structured such that ownership reverts to DPU after tax advantages are fully utilized. In the case of the 15th East Reservoir, although a 274-kW solar installation was evaluated at the 15th East Reservoir, a smaller installation of approximately 25-kW could entirely offset electric usage on-site. Financial incentives to install a larger system are limited and the NPV would improve if the system were sized to meet the electricity needs of the on-site facility.

analysis, they would significantly reduce the overnight capital cost of several projects. For example, using a power purchase agreement (PPA) for solar photovoltaic installations allows DPU to realize savings of up to 30 percent due to a federal tax incentive for solar. Similar savings are achieved if DPU were to receive an incentive through the Utah Solar Incentive program. A portfolio of available financing options is described in Chapter 8, including the Blue Sky Grant Program, Qualified Energy Conservation Bonds, the U-Save Energy Program, the Utah Solar Incentive Program, and PPAs. Table C summarizes the challenges and recommendations associated with each project.

Salt Lake City Water Reclamation Facility

At the Salt Lake City Water Reclamation Facility, two cogeneration engines already exist and are used to convert excess biogas into clean energy. However, the current rate schedule at the facility does not allow for the sale of excess electricity to the grid, so the engines are not both operated at the same time for fear that they will produce excess energy. Switching to a rate schedule which does allow for the sale of excess electricity to the grid would allow DPU to operate both engines concurrently, burn more waste biogas, and produce more clean electricity to offset on-site electricity use. In the future, DPU may be required to convert to a Bio Nutrient Removal (BNR) process, which will reduce the amount of excess biogas production while also increasing electricity usage. Although the NPV of biogas cogeneration is negatively impacted by a BNR process, DPU could better utilize existing cogeneration engines with no infrastructure upgrades until required to switch to a BNR process.

The Salt Lake City Water Reclamation Facility uses cogeneration engines to convert waste biogas into clean electricity. By switching to a rate schedule that allows the Water Reclamation Facility to export excess power to the grid, the Facility could operate the existing cogeneration engines more frequently, make use of more waste biogas, and produce more clean energy.

Mountain Dell Dam

A hydroelectric turbine at the existing Mountain Dell Dam could be used to generate power to offset on-site electricity usage and poses no significant technical or regulatory challenges. If the future regulatory costs of carbon regulation are assumed to be \$50/$MTCO_2e$, a hydroelectric turbine at the Mountain Dell Dam has an attractive NPV.

B11-R13 Pressure Reducing Valve (PRV)

A micro-hydroelectric turbine at the B11-R13 PRV could produce electricity from the energy that is generated when the pressure in water pipelines is reduced before it is delivered to homes and

businesses. The NPV of this site is attractive if the site were able to virtually net meter and electricity produced at this PRV could be used to offset DPU load at other facilities. Virtual net metering is not currently available in Utah and there is no significant load at the PRV itself, so the electricity could instead be sold to the grid. The NPV of the project is still attractive even without virtual net metering when future carbon costs are assumed to be \$50/MTCO$_2$e.

Terminal and Park Reservoirs

Reservoirs can be used to produce clean energy in several different ways. A hydroelectric turbine at the existing Mountain Dell Dam could be used to generate power and offset on-site electricity usage. Solar photovoltaic panels can be sited on top of enclosed reservoirs, such as the 15th East Reservoir and the Terminal and Park Reservoirs, so that otherwise un-utilized real estate can become a source of clean electricity.

A large solar photovoltaic installation at these reservoirs could produce a significant amount of clean energy, however there is minimal DPU load on-site. If virtual net metering were available it would improve the NPV of this project significantly. Although leases and PPAs were not considered in this analysis, a lease or PPA would allow DPU to take advantage of a federal tax incentive through a third-party ownership structure and could result in significant upfront cost reductions (up to 30 percent). A PPA can be structured such that ownership reverts to DPU after tax advantages are fully utilized, and using a PPA would also significantly impact the assumed NPV. Notably, this project has the potential for the biggest environmental impact. Solar photovoltaic panels could produce enough electricity to offset 3,381 MTCO$_2$e of emissions associated with utility electricity. This represents approximately 13 percent of the GHG emissions associated with DPU's consumption of purchased electricity and natural gas.

15th East Reservoir

A 274-kW solar installation was evaluated at the 15th East Reservoir which would produce an average of 335,000 kWh of electricity each year. However, electricity meters located at this site report that the on-site load is only 70,000 kWh of electricity each year. A smaller 25-kW installation at this site could net meter and offset on-site electricity usage, however this option was not evaluated. Although DPU could build a 274-kW installation, as evaluated in this study, and contract to sell the excess electricity, a smaller net metered solar installation will offer a more attractive NPV. A lease or a PPA, which was not considered in this evaluation, would allow DPU to take advantage of a federal tax incentive through a third-party ownership structure and could result in upfront cost reductions of up to 30 percent.

Salt Lake City Wastewater Heat Recovery

Wastewater heat recovery at a site located adjacent to DPU's main office in Salt Lake City would utilize a heat exchanger to extract heat from wastewater flowing in the sewer trunkline along West Temple and provide space heating to DPU's main office. Although this project would allow DPU to reduce natural gas purchases, it would increase electricity usage. Even when the cost of carbon regulation is assumed to be $50/MTCO_2e$, the NPV of the cost of utility service of the wastewater heat recovery system is estimated to exceed the value of natural gas service provided by Questar over the 30 year-life of the project.

Table 1-3. Summary of Recommendations

Site	Technology	Summary	Challenges	Recommendations
Salt Lake City Water Reclamation Facility	Biogas Cogeneration	Best and most cost-effective opportunity for DPU to generate renewable electricity. A change in operations of engines would enable SLCWRF to burn additional biogas or NG and generate at least 50 percent more electric power.	• Federal water quality standards may require DPU to switch to a bio-nutrient removal (BNR) process in the future. • Existing tariff schedule does not allow generation to exceed load at the site.	• Make operational changes to increase capacity factor of engines and more effectively utilize biogas from site • Evaluate benefits of implementing a FOG program to increase biogas production • Evaluate whether SLCWRF can move to a different rate schedule that would enable it to sell excess electricity back to RMP.
	Biogas Cogeneration (BNR, NG)	Bio-nutrient removal process (BNR) may be required in the future and will have a negative impact on biogas production and make the existing cogeneration system uneconomic.	• Changing to a BNR process will use more electricity and produce less biogas as a byproduct	• If required to switch to BNR process, explore viability of supplementing biogas production by implementing a FOG program.
15th East Reservoir	Roof-mounted Solar PV	Excellent candidate for roof mounted solar PV technology. Limited load at the site makes a 274 kW system uneconomic however economics would improve significantly with a 25 kW system designed to meet site load.	• Minimal electricity usage on site • Unfavorable QF power purchase rates	• Additional analysis should be conducted by DPU to evaluate viability of installing smaller capacity system designed to meet load. • Explore economics of RMP grants and entering into a third party PPA or lease structure to significantly reduce up front capital cost and take full advantage of 30% federal tax credit
West Temple Trunkline	Wastewater Heat Recovery	At this site and given the technology configuration evaluated, the project is uneconomic and would offset natural gas consumption but increase electricity use.	• Low natural gas and electricity prices. • There are many more economically viable renewable energy projects at DPU owned sites.	• A technology demonstration should be considered if other partners, i.e. Questar or RMP, can be found to offset the upfront capital investment a technology demonstration project could be viable.
Mountain Dell Dam	Hydroelectric	An attractive site for renewable energy development because of the ease of interconnection, potential to offset 75% of load and it is eligible for net metering.		• This project is an excellent candidate to for development in the next 5 years. • Evaluate alternative financing options such as a PPA or lease to improve the economics
Terminal & Park Reservoirs	Roof-mounted Solar PV	Solar PV at this site has the potential to produce a large amount of renewable energy and offset GHG emissions.	• $11.3 million capital costs • Unfavorable QF power purchase rates and minimal site load make this project uneconomic	• Evaluate the use of a PPA or lease financing arrangement to take advantage of federal tax credits and apply to the Utah Solar Incentive Program to significantly improve the economics of the project. • Negotiate with RMP to allow this project to offset load at other DPU loads at full retail price.
Pressure Reducing Valve Station B11-R13	Hydroelectric Reverse-pump turbine	Significant RE generation potential. Cost effective when $50 price for carbon included in financial analysis. Attractive technology that can be used at numerous sites on SLC water delivery system.	• Most PRVs have minimal on-site load • Low QF power purchase terms	• Negotiate with RMP to allow this project to offset load at other DPU loads at full retail price. • Economics could be improved by adopting alternative financing approaches.

2.0 INTRODUCTION

2.1 Background

In early 2013, Salt Lake City introduced its *Sustainable Salt Lake – 2015 Plan*, a roadmap designed to enhance Salt Lake City's resiliency, vitality, and sustainability. The plan lays out key goals and strategies for Salt Lake City regarding renewable energy and GHG reductions, including a long-term goal to transform all Salt Lake City municipal facilities into "net zero" energy users. Short-term strategies include increasing renewable energy generation on Salt Lake City's municipal facilities to 2.5-MW and supporting the installation of 10-MW of photovoltaic solar on buildings in the Salt Lake metropolitan area, both by 2015. Reaching these targets will help Salt Lake City reach its 2015 climate change goals to reduce GHG emissions attributed to city buildings and fleet by 13 percent by 2015.

The Salt Lake City Department of Public Utilities (DPU) provides drinking water, wastewater treatment, and other essential services to residents and visitors of the Salt Lake Valley. In line with its mission to serve the Salt Lake Valley and also protect our environment, - DPU is striving to reduce its reliance on electricity generated from fossil fuels and diversify its energy portfolio through the development of renewable energy resources.

DPU has already taken steps towards incorporating more sustainable energy practices in its operations: a significant portion of DPU's water distribution system is designed to rely on gravity rather than electric pumps. Methane produced by anaerobic digesters at the Salt Lake City Water Reclamation Facility (SLCWRF) on average generates six million kWh of electricity per year. The electricity from this cogeneration system is used to power treatment plant operations, and preliminary assessments suggest there is excess digester capacity at the facility. In addition, DPU has examined other renewable energy options, including micro-hydroelectric opportunities in its water distribution system, and DPU and Salt Lake City properties that are potentially suitable for solar photovoltaic (PV) systems.

DPU is interested in expanding its efforts to develop renewable energy and reduce its reliance on electricity generated from fossil fuels as it provides these essential services to its service area and county residents. DPU owns and manages Pressure Reducing Valve (PRV) stations on its water distribution system, water rights, dam sites, a wastewater treatment plant that produces methane, covered reservoirs, building rooftops and other properties that could potentially support renewable energy projects. The access to these sites and the potential availability of wind, solar, biogas and hydroelectric resources presents an opportunity to develop new sources of clean energy, and that could position DPU as a leader in helping Salt Lake City achieve its renewable energy and GHG emissions goals.

In recognition of the opportunity to further develop its renewable energy potential at sites owned by Salt Lake City, DPU issued a Request for Qualifications (November 2013) and a Request for

Proposals (December 2013) Renewable Energy Study RFP No. 51360066, seeking the technical expertise and analysis needed to conduct an evaluation of existing and potential renewable energy projects, and to develop a Renewable Energy Plan for DPU.

2.2 Project Team

To support Salt Lake City's on-going efforts to diversify its energy portfolio and reduce its reliance on carbon-intensive fossil fuels, DPU selected a consultant team headed by Energy Strategies that included Sunrise Engineering, Utah Clean Energy, and Carollo Engineers (Consultant Team) to conduct the renewable energy feasibility assessment. The Consultant Team members have extensive experience helping private companies, institutions of higher education, and government agencies evaluate the technical, economic and regulatory feasibility of renewable energy and other clean energy technologies.

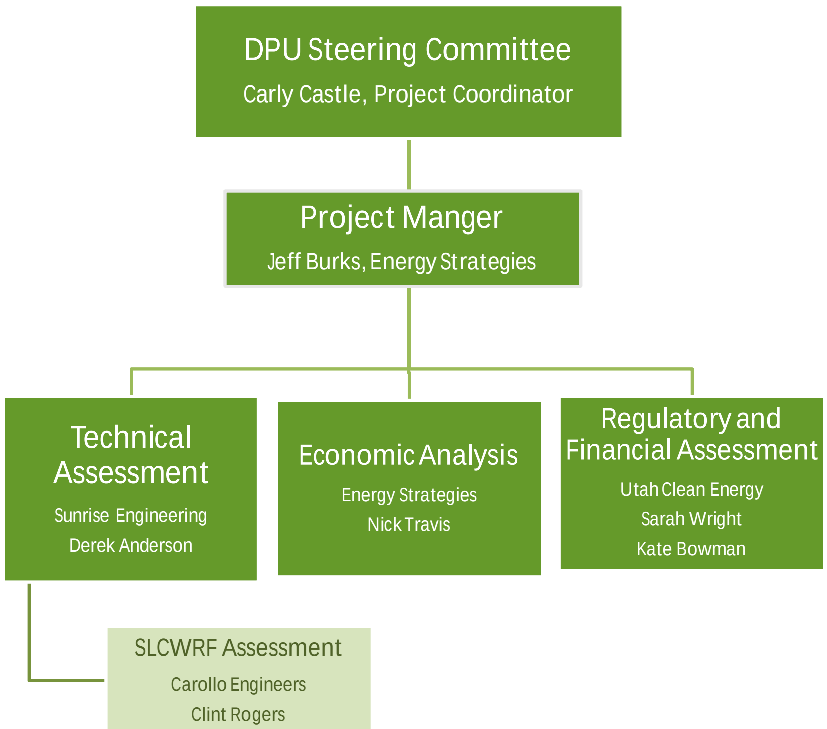
Energy Strategies L.L.C. has conducted over 100 technical, economic, and financial investment analyses and regulatory assessments of utility scale; and distributed renewable energy and co-generation systems for both public and private sector clients. Sunrise Engineering and Carollo Engineers have provided engineering assessments, design, and installation services for numerous small hydroelectric, micro-hydroelectric, biogas-to-energy, wind, and solar projects for both municipal governments and private developers. Utah Clean Energy has worked closely with Salt Lake City on their solar energy, energy efficiency, and climate policy initiatives since 2002, and provides integral experience and proven success within state regulatory and policy arenas to assist in the development and implementation of the Renewable Energy Plan.

In addition to the Consultant Team, Carly Castle, Special Projects Coordinator for DPU, and the DPU Steering Committee rounded out the project team that worked on the renewable energy development planning project. DPU Steering Committee members included:

- Jeff Niermeyer, Director
- Tom Ward, Deputy Director
- Laura Briefer, Deputy Directr
- Tyler Poulson, Program Manager, Division of Sustainability
- Jim Lewis, Finance Manager
- Mark Christensen, Financial Analyst
- Dale Christensen, Water Reclamation Manager
- Giles Demke, Wastewater Plant Maintenance Engineer
- Mark Stanley, Operations and Maintenance Superintendent
- Jesse Stewart, Water Quality Manager

The Consultant Team worked closely with Salt Lake City DPU personnel to ensure that all renewable energy options were identified and to implement a scope of work that would result in an actionable plan. If implemented, the plan will support Salt Lake City and DPU's goals to reduce dependence on fossil-generated electricity, increase the deployment of renewable energy, and reduce its GHG emissions.

Figure 2-2. Project Team



2.3 Overview of Approach

The evaluation of potential renewable energy projects at locations owned by Salt Lake City and DPU was divided into three sequential phases: a Phase I Preliminary Site Scoping Evaluation, a more detailed Phase II Site-Specific Evaluation, and a third phase evaluation where a cross section of six renewable energy projects evaluated in Phase II were selected to undergo a regulatory assessment and economic analysis.

The purpose of the Phase I Preliminary Scoping Evaluation was to conduct a high-level site assessment to identify, evaluate, and rank sites located at Salt Lake City properties and facilities based on the sites' ability to support a renewable energy project and generate power. The evaluation was designed to provide an initial, high-level screening of potential sites and provide DPU with a prioritized list of sites recommended for more detailed evaluation in Phase II.

The purpose of the Phase II assessment was to provide DPU with sufficient detail about siting characteristics, economic feasibility, regulatory pathways, and options for financing renewable energy projects to enable Salt Lake City to develop an implementation plan for project development. The

19 renewable energy projects selected from Phase I were screened through three sequential assessments in Phase II. The first, a detailed on-site assessment, was conducted by Sunrise Engineering (or by Carollo Engineers for the Salt Lake City Water Reclamation Facility). The on-site assessments recognized that even though a site may exhibit favorable generation potential in Phase I, environmental conditions, geological characteristics, interconnection access, and permitting and zoning limitations may preclude development of a renewable energy project at the location. An on-the-ground detailed assessment of 20 criteria was conducted at each site, including generation potential, interconnection and permitting requirements, zoning standards, and sustainability characteristics. Each site assigned a score for each assessment category using a 0 to 5 scale. Scorecard results were tabulated and input into a spreadsheet tool that scored each project on a weighted 100 point scale. These projects were then ranked according to score with 100 representing the best possible score.

Using the ranked results and input from the Consultant Team, the DPU Steering Committee selected a representative cross section of six projects from the 19 ranked projects taking into consideration technology, location, generation capacity, cost effectiveness, and project visibility. Six projects were selected for further evaluation, including a comprehensive evaluation of the regulatory feasibility and economic viability of each project.

Utah Clean Energy completed a regulatory assessment and identified financing options for each project. The regulatory assessment details current statutes, rules, and regulations that have the potential to impact the development, interconnection, and delivery of each renewable energy project evaluated.

Energy Strategies employed an annual cash flow model to evaluate the economic viability of each of the six renewable energy projects relative to a “Business as Usual” (BAU) scenario. The economic model provided an incremental analysis and comparison of both cash flow and GHG emissions savings associated with each proposed renewable energy project compared to the BAU case to establish the cost effectiveness and environmental benefits of each project.

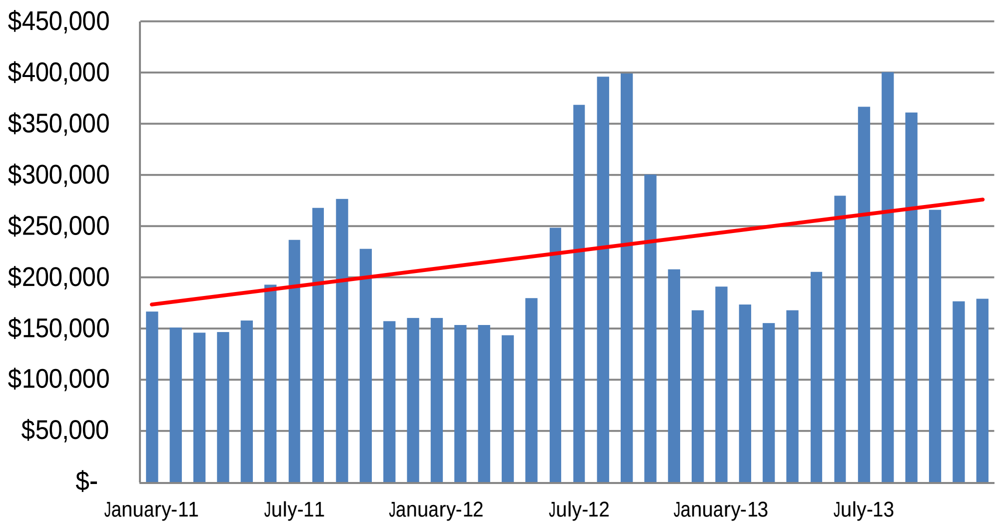
The results of the evaluation process employed by the Consultant Team were intended to provide DPU with sufficient detail on the 19 renewable energy projects evaluated in Phase II to allow for their subsequent development. A detailed description of methodologies for screening of renewable energy projects, detailed evaluations of site characteristics, economics, and regulatory options was provided in this report.

3.0 ENERGY USE PROFILE AND CO_2 EMISSIONS FOOTPRINT

Energy is one of the biggest economic and environmental costs of delivering water to taps and treating wastewater, and DPU is striving to reduce its reliance on coal and fossil fuels as it provides these essential services to its service area.

DPU supplies more than 349,000 customers in Salt Lake City and surrounding areas in Salt Lake County with culinary water, providing an average of 89.8 million gallons of water daily. Delivery of water to Salt Lake City service area residents depends on a complex network of free-flowing streams, reservoirs, aqueducts, water treatment plants, distribution systems, and water mains. DPU also collects and treats wastewater at the Salt Lake City Water Reclamation Facility (SLCWRF), a 56-million gallon wastewater treatment plant. Additionally, DPU manages the street lighting enterprise fund, which is responsible for maintaining and operating more than 15,000 street lights within Salt Lake City. To manage this vast system, DPU uses a significant amount of energy. In 2013, DPU consumed 32,320 MWh of electricity and burned 16,819 decatherms (DTH) of natural gas to operate the systems it manages. Figure 3-1 illustrates DPU's electricity and natural gas expenditures by month.

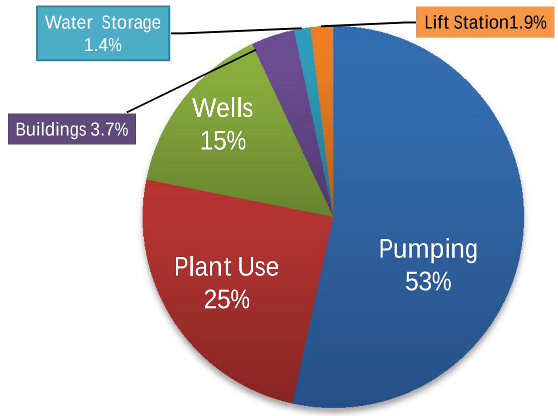
Figure 3-1. Electricity and Natural Gas Expenditures by Month



DPU is served by two electric utilities; Rocky Mountain Power (RMP) provides the vast majority of DPU's electricity, and Murray City Power provides power to a single pump station. The electricity provided by RMP has a significant environmental footprint in terms of water consumed and emissions of criteria pollutants and CO_2. Electric rate structures vary by facility.

In general, the majority of DPU's electricity use is from pumping water and wells to supply water to its customers. About 75 percent of DPU's electricity demand is assigned to wells and pumps, as illustrated in Figure 3-2.

Figure 3-2. Energy Consumed by End Use



3.1 Electricity

DPU has a peak energy demand in the summer months and its energy demand is correlated to its customers' water demand. Unfortunately, DPU's demand for electricity peaks during the summer (when the cost of electricity is higher), and electricity demand is lower in the winter (when the cost of electricity is lower). The monthly and yearly changing electricity demand can be seen in Figure 3-3.

In 2013, DPU spent $2.8 million dollars on electricity alone. DPU pays six different rates for electricity, which are based on RMP rate schedules for different types of facilities. The average price paid by DPU in 2013 was 8.7 cents per kWh, an increase from the average price in 2011 (7.9 cents/kWh) and in 2012 (8.2 cents/kWh). DPU paid approximately 10 percent more for electricity in 2013 than in 2011, as shown in Table 3-1. This change in the average price is based on a number

Figure 3-3. Electricity Consumption by Month 2011-2013

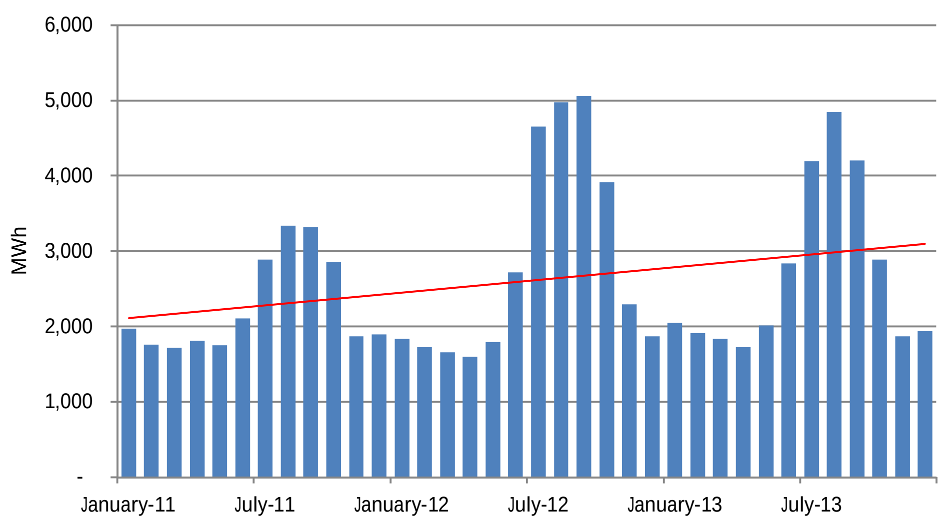


Table 3-1. DPU Electricity Use

Year	MWh	Average $/kWh	Dollars Spent	Emissions Tons CO_2[2]
2011	27,295	$0.079	$ 2,158,849	22,655
2012	34,085	$0.082	$ 2,774,725	28,291
2013	32,320	$0.087	$ 2,805,383	26,826

of factors, including higher RMP electricity rates and more purchases of electricity during summer peak energy times.

The challenge for DPU in future years will be to manage costs given a growing population and increasing electricity costs. For example, in 2011 DPU spent $2.1 million on electricity, however, in 2013 DPU spent $2.8 million on electricity (an increase of $700,000 or, 23 percent, in two years). This increase in energy expenditures can be seen in Figure 3-3, and the upward trend is illustrated by the red trend line.

3.2 Natural Gas

DPU's natural gas use is very different than its electricity use. Unlike electricity demand, DPU's natural gas usage peaks in the winter months to meet heating demand at plants and buildings. Questar Gas Company (Questar) supplies DPU with natural gas, and DPU's demand follows a typical pattern for natural gas with higher peaks in the winter and less demand in the summer.

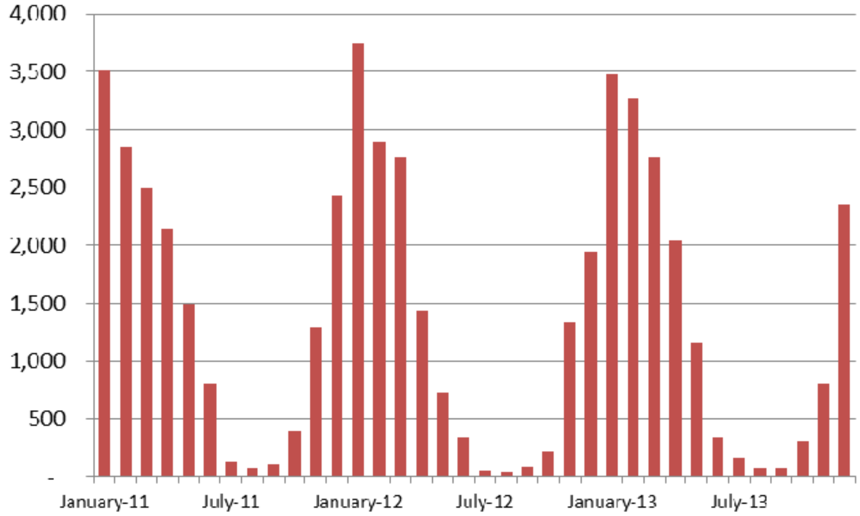
Unlike electricity, DPU's natural gas use and spending has been stable, ranging from $133,661 in 2011 to $123,941 in 2013, as shown in Table 3-2. Figure 3-4 illustrates natural gas consumption by month between 2011 and 2013.

Table 3-2. DPU Natural Gas Use

Year	Decatherm (DTH)	Average $/ DTH	Dollars Spent	Emissions Tons CO_2
2011	17,740	$102	$133,661	1,048
2012	15,609	$83	$110,352	922
2013	16,819	$108	$123,941	994

[2] Based on Salt Lake City's assumption that the power provided to them has an emission rate of 1.66lbsCO_2/kWh.

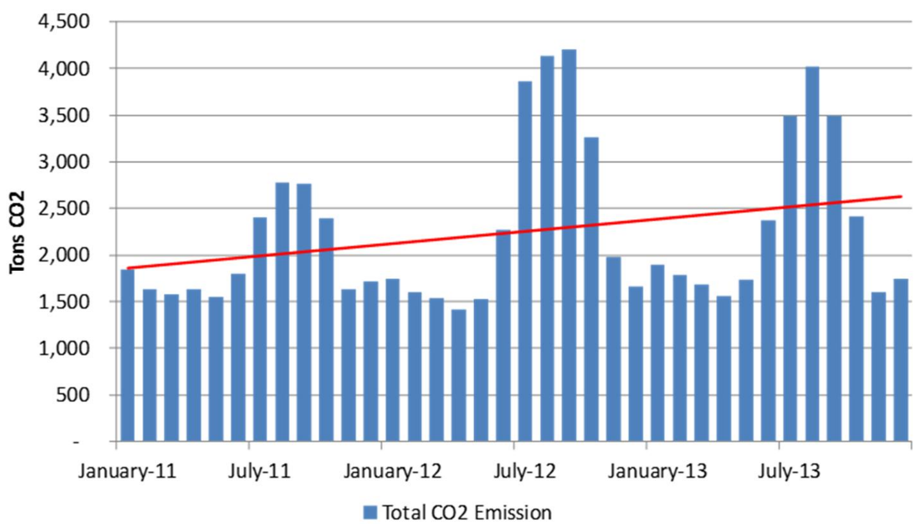
Figure 3-4. Natural Gas Consumption by Month 2011-2013 (DTh)



3.3 DPU Energy Use Carbon Footprint

Salt Lake City estimates there are 1.66 lbs/kWh of CO_2 emissions associated with its electricity use and 13.446 lbs/DTH carbon emission associated with burning natural gas. PacifiCorp, Rocky Mountain Power's parent company, produces 65 percent of its electricity from coal (based on PacifiCorp's 2013 Resource Plan).[3] DPU uses significantly more electricity than natural gas, which means DPU's CO_2 emissions are primarily due to electricity use. In 2013, the CO_2 emissions associated with DPU's consumption of electricity and natural gas totaled 27,820 tons. For the three years data was collected, CO_2 emissions ranged from a low of 23,703 tons in 2011 to a high of 29,213 tons the following year (Figure 3-5).

Figure 3-5. DPU Carbon Footprint from Energy Use 2011-2013



[3] PacifiCorp Integrated Resource Plan, https://www.rockymountainpower.net/about/irp.html.

4.0 PHASE I PRELIMINARY SCOPING EVALUATION

The objective of the Phase I Preliminary Scoping Evaluation was to identify, evaluate, and rank sites located at Salt Lake City properties and facilities which have the potential for renewable energy development. The evaluation was designed to organize 151 sites into a prioritized list based on the evaluation criteria, and then identify those sites which are recommended for evaluation in Phase II.

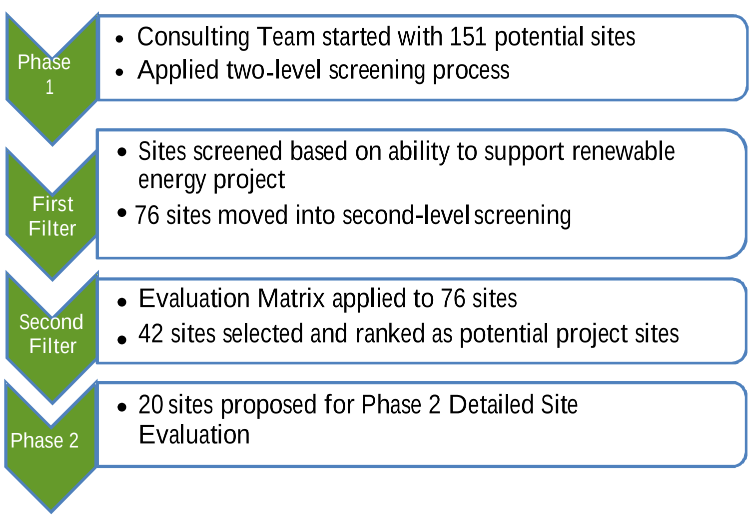
The Phase I evaluation included 50 potential solar photovoltaic (PV) sites (35 water storage facilities, 10 buildings, and 5 open land parcels); 95 potential hydroelectric sites (51 PRV sites, 44 water rights hydropower applications sites, 4 canal drop structures, and 1 pipeline); 2 potential wind power sites; 3 potential wastewater heat recovery sites; and 1 cogeneration site. Several of the water rights hydropower application sites overlapped with PRV sites and the evaluated pipeline sites.

4.1 Assessment Methodology

The 151 sites identified by DPU were put through a two-level screening evaluation. The first level filter assessed the ability of the site to support a renewable energy project and generate power. Sites identified as incapable of supporting a project were immediately eliminated from further consideration (see First Filter in Figure 4.1).

Sites were eliminated if they did not exhibit the necessary physical characteristics to viably support a renewable energy project and generate power. Sites identified as capable of supporting a project were funneled to the second-level filter, a matrix analysis of the project potential based on 6 criteria. Figure 4-1 illustrates the overall process.

Figure 4-1. Phase I Screening Methodology



The purpose of the matrix analysis was to objectively score and rank the remaining sites on a quantitative basis. Projects were ranked in order to select priority project sites which progressed to Phase II of the evaluation.

The matrix employed to conduct the second screening included three site evaluation criteria: annual generation potential, site characteristics, and environmental factors. Annual generation consists of the generation potential at a site. Site characteristics included the potential to offset existing site load, the potential to interconnect and the distance to power distribution infrastructure, and the approximate percentage of DPU load that could be potentially displaced at the site (if available). Environmental factors considered included perceived impact on the surrounding environment and local acceptance of a project. Table 4-1 illustrates the Phase I screening matrix criteria and scoring.

Table 4-1. Phase I Screening Matrix Criteria and Scoring

Category	Weighting Factor	5	4	3	2	1	0
Annual Generation							
Generation (kWh)	5	≥1,000,000	500,000-1,000,000	250,000-500,000	100,000-250,000	<100,000	
Site Characteristics							
Potential to Offset Existing DPU Load	2	Yes					No
Potential to Interconnect	3	Yes		Likely		Maybe	No
Proximity to Load & Distribution Infrastructure	4	≤500 ft	500-1000 ft	1000-1500 ft	1500-2000 ft	2000-2500 ft	2500+ ft
Percentage of DPU Load Displaced	1	81%-100%	61%-80%	41%-60%	21%-40%	1%-20%	<1%
Environmental Factors							
Environmental Impact	5	Negligible	Minor			Moderate	Major
Public Acceptance		100% Positive	90% Positive	80% Positive	70% Positive	60% Positive	50% Positive

Each criterion was given a rating of one through five, five being the highest, and weighted in such a way that if a site were to receive a rating of five for all criteria, it would accumulate a total score of 100 points.

4.2 Solar Photovoltaic Generation

Several types of solar photovoltaic systems were evaluated for this project, including ground-mounted systems of various sizes, small utility-scale systems, and distributed rooftop solar systems. Major factors considered in the design of these systems included shading, solar insolation (the average amount of solar radiation available in a given area and time), location, and mounting considerations. The advantage of the roof-mounted systems is that they require no additional land and can take advantage of existing DPU or City-owned buildings with flat rooftops. Land requirements for PV installations depend on many factors such as tracking technology, efficiency, and capacity factor. Common practice is to state land requirements in terms of acres per MW. Estimates from recent environmental impact studies done for large scale solar PV plants under development in California and Nevada suggest a requirement of between six and nine acres per MW is common.[4]

[4] NREL, "Land-Use Requirements for Solar Power Plants in the United States." http://www.nrel.gov/docs/fy13osti/56290.pdf

Fifty sites were evaluated for solar photovoltaic (PV) power potential. The sites consisted of 35 water storage facilities (reservoirs and tanks), 10 buildings or building complexes, and 5 open land parcels. Due to their proximity, Terminal Reservoir and Park Reservoir were combined as one site, as well as Granite Oaks Tank and Telford Reservoir, leaving 48 sites for evaluation. All of the solar PV sites exhibited the potential to generate electricity, so none of the solar PV sites were eliminated by the level one filter. Table 4-2 provides a summary of the 48 solar PV sites evaluated.

Table 4-2. Solar PV Potential Evaluation Summary

Site Name	Site Type	Capacity (kW)	Average Annual Generation (kWh)	On-Site or Adjacent Loads
Terminal Reservoirs/Park Reservoir	Water Tank/Res. - Roof Mount	1562	2,280,520	Wells 3580 E #4 & #5
Baskin Reservoir	Water Tank/Res. - Roof Mount	395	576,700	Bonneville PS
15th East Reservoir	Water Tank/Res. - Roof Mount	290	423,400	500 S Well & University PS
Military Reservoir	Water Tank/Res. - Roof Mount	256	373,760	Military PS
Victory Road Reservior	Water Tank/Res. - Roof Mount	248	362,080	
Wilson Reservoir	Water Tank/Res. - Roof Mount	241	351,860	Arlington Hills PS
Marcus Reservoir	Water Tank/Res. - Roof Mount	190	277,400	
Morris Reservoir	Water Tank/Res. - Roof Mount	176	256,960	North Bench PS
McEntire Reservoir	Water Tank/Res. - Roof Mount	142	207,320	
13th East Reservoir	Water Tank/Res. - Roof Mount	114	166,440	
Ensign Downs Lower Tank	Water Tank/Res. - Roof Mount	105	153,300	Ensign Downs PS
Tanner Reservoir	Water Tank/Res. - Roof Mount	67	97,820	Dyers Inn Well
Granite Oaks Tank/Telford Reservoir	Water Tank/Res. - Roof Mount	54	78,840	Granite Oaks PS
Tavaci Tank	Water Tank/Res. - Roof Mount	47	68,620	Tavici PS
Capital Hill Tanks	Water Tank/Res. - Roof Mount	45	65,700	
Mt Opympus Tanks	Water Tank/Res. - Roof Mount	45	65,700	Mount Olympus PS
East Bench Tanks	Water Tank/Res. - Roof Mount	38	55,480	Carrigan Cove PS
Ft Douglas Reservoir	Water Tank/Res. - Roof Mount	34	49,640	
Emigrattion Reservoir	Water Tank/Res. - Roof Mount	31	45,260	
White Reservoir	Water Tank/Res. - Roof Mount	30	43,800	
Perry' Hollow Tank	Water Tank/Res. - Roof Mount	28	40,880	
Teton Tanks	Water Tank/Res. - Roof Mount	15	21,900	
Eastwood Tanks	Water Tank/Res. - Roof Mount	14	20,440	Eastwood PS
Carrigan Cove Tank	Water Tank/Res. - Roof Mount	10	14,600	
Ensign Down Upper Tank	Water Tank/Res. - Roof Mount	9	13,140	
Canyon Cover Upper Tank	Water Tank/Res. - Roof Mount	9	13,140	
Canyon Cover Lower Tank	Water Tank/Res. - Roof Mount	9	13,140	
Ferguson Tank	Water Tank/Res. - Roof Mount	9	13,140	
Raineer Tank	Water Tank/Res. - Roof Mount	6	8,760	
North Bench Tank	Water Tank/Res. - Roof Mount	5	7,300	
Neff's Cayon Tank	Water Tank/Res. - Roof Mount	4	5,840	
Olympus Cove Tank	Water Tank/Res. - Roof Mount	2	2,920	
Millcreek Tank	Water Tank/Res. - Roof Mount	2	2,920	Lower Boundary PS
Boeing	Building - Roof Mount	733	1,070,180	Building Load
XPEDX	Building - Roof Mount	456	665,760	Building Load
Highland High School	Building - Roof Mount	333	486,180	Building Load
Roberts Restaurant and Adjacent Building	Building - Roof Mount	267	389,820	Building Load
410 N. Wright Brothers Drive	Building - Roof Mount	228	332,880	Building Load
Salt Lake City Sports Complex	Building - Roof Mount	187	273,020	Building Load
The Leonardo	Building - Roof Mount	91	132,860	Building Load
Sorenson Multicultural and Unity Fitness Center	Building - Roof Mount	58	84,680	Building Load
SLCDPU Buildings	Building - Roof Mount	57	83,220	Building Load
Horizonte Training Center	Building - Roof Mount	13	18,980	Building Load
South Lift	Open Parcel - Ground Mount	299	436,540	South Sewer LS
Smith & Loveless	Open Parcel - Ground Mount	85	124,100	Smith & Loveless and 4000 W Sewer LS
Concord Lift	Open Parcel - Ground Mount	79	115,340	Concord Sewer LS
6200 S. Well	Open Parcel - Ground Mount	63	91,980	6200 S Well & 6200 S Irrigation PS
Greenfield Village	Open Parcel - Ground Mount	51	74,460	Greenfield Village Well

For purposes of estimating capacity and generation it was estimated that 33.5 percent of a rectangular roof, or 30 percent of a circular roof, can be effectively used for installation of PV modules. The estimated capacity and average annual Alternating Current (AC) generation at each of the sites evaluated are summarized in Table 4-2.

Sites that were not adjacent to a DPU load and found to have an average annual generation less than 100,000 kWh were eliminated from further detailed evaluation of site characteristics and environmental factors in the matrix. Nineteen sites were eliminated based on these criteria, leaving 31 sites fully evaluated and ranked.

4.3 Hydroelectric Generation

Three hydroelectric generation technologies were evaluated for potential use at DPU and Salt Lake City sites: a conventional penstock-turbine configuration installed in conjunction with surface water impoundments; reaction turbines installed at Pressure Reducing Valve (PRV) stations used to control pressure in Salt Lake City's culinary water pipeline system; and micro-siphon hydroelectric generation systems that rely on the flow of surface waters in a canal or similar conveyance with a drop structure.

Ninety-five sites were evaluated for hydroelectric potential. The sites consisted of 51 PRVs, 44 water rights hydropower applications sites, four canal drop structures, and one pipeline. Several of the water rights hydropower application sites overlapped PRV sites and the evaluated pipeline site, which brought the total to 95 sites evaluated. Thirty-one of the PRV stations, 40 of the water rights hydropower application sites, and one of the canal drop structures were eliminated after the level one filter was applied. The estimated capacity and average annual generation at each of the 24 remaining sites potentially suitable for installation of hydroelectric technology are summarized in Table 4-3.

Sites that were not adjacent to a DPU load and that were found to have an average annual generation less than 100,000 kWh were eliminated from further detailed evaluation of site characteristics and environmental factors in the matrix. Eleven sites were eliminated based on these criteria, leaving 13 sites fully evaluated in the matrix.

4.4 Wind Power

Wind power is extracted from air flow using wind turbines to produce electric power. Wind power is very consistent from year to year but has significant variation over shorter time scales. As a renewable resource, wind is classified according to wind power classes, which are based on wind speed frequency distributions and air density. These classes range from Class 1 (the lowest) to Class 7 (the highest). In general, at a 50-meter height, wind power Class 4 or higher could be useful for generating wind power with turbines in the range of 250-kW to 750-kW.

Table 4-3. Hydroelectric Potential Evaluation Summary

Site Name	Site Type	Capacity (kW)	Average Annual Generation (kWh)	On-Site or Adjacent Loads
D74-DV1	PRV	359	1,310,352	
B35-R18	PRV	422	1,539,757	
B11-R13	PRV	292	1,064,622	
C41-R20	PRV	281	1,025,114	
B6-R73	PRV	266	970,091	
D69-R40	PRV	63	228,660	
A23-R5	PRV	59	216,797	
C1-R74	PRV	54	196,973	
F78-CR28	PRV	41	151,340	
G35-CR53	PRV	36	131,639	Private Well
E10-R55	PRV	24	88,569	
F60-CR47	PRV	19	70,807	
G38-CR57	PRV	17	62,052	7800 S PS
C12-R15	PRV	16	58,332	
D41-R35	PRV	13	46,610	
B36-R19	PRV	13	46,447	
D69-R39	PRV	11	38,378	
C41-R22	PRV	9	33,786	
F26-CR14	PRV	2	6,834	
F76-CR48	PRV	1	2,546	Dyers Inn Well
Mountain Dell Dam	Surface Water	410	2,370,536	Parley's WTP
Big Spill	Surface Water	15	65,520	On-site pump, lighting and gates
The Tower	Surface Water	8	32,256	On-site gates
2100 S. Plaza	Surface Water	2	8,784	On-site gates

For the evaluation of wind power potential, DPU requested the evaluation of two sites, Mountain Dell Reservoir and the adjacent water treatment plant. For the first level filter the Consultant Team utilized the U.S. Department of Energy and NREL 50-meter height wind resource map for Utah.[5] The map shows Wind Power Density (WPD) estimates at 50 meters (approximately 164 feet) above the ground and identifies wind resources that could be used for community-scale wind development using wind turbines at 50 to 60-meter hub height. The evaluation of the wind resource map indicates that the larger contiguous areas of good-to-excellent resources are located in western Utah, especially near the Raft River Mountains near the Idaho border, and in the area near Milford. Other good–to–excellent wind resource areas are located on the higher ridge crests throughout the state. In the Salt Lake Valley, the best wind resources (Class 2 to Class 4) are located at the mouths of Parley's, Millcreek, Big Cottonwood, and Little Cottonwood Canyons, and along Traverse Ridge.

The evaluation of the wind resource potential at the Mountain Dell Reservoir sites and the adjacent water treatment plant indicate these sites are located in Class 1 (the lowest) zone where the wind speed at the 50-meter height ranges from zero to 12.5 miles per hour. Accordingly, Mountain Dell

[5] Utah 50-Meter Wind Map, U.S. Department of Energy and National Renewable Energy Laboratory http://apps2.eere.energy.gov/wind/windexchange/maps_template.asp?stateab=ut.

Reservoir and the adjacent water treatment plant were not considered to be viable candidates for wind power generation and eliminated from consideration.

4.5 Wastewater Heat Recovery

Municipal wastewater is a promising source of energy which can be harnessed by using the discharge of water through sewer mains as a heat source and retrofitting lines with heat exchangers in conjunction with a larger heat pump. There are two different ways of recovering energy from wastewater: installation of a heat exchanger on the bed of the sewer or an external heat exchanger with an upstream pump and filter installation.

For the evaluation of wastewater heat recovery opportunities, DPU requested the technology be evaluated for its potential application at treated discharge water at the SLCWRF where it could be used for drying sludge. Additionally, the sewer main along 500 South near the Central Heating Plant, and the sewer main along West Temple next to the DPU campus were evaluated to supplement heating load at adjacent buildings.

In the Phase I screening it was determined that utilizing wastewater heat recovery at SLCWRF to increase the efficiency of drying sludge was not likely an economical or operationally feasible application of the technology. A demonstration project at the West Temple trunkline adjacent to the DPU campus was evaluated instead.

4.6 Cogeneration at SLCWRF

Carollo Engineers conducted an assessment of the SLCWRF to identify opportunities to expand or replace cogeneration technology at the site. A preliminary screening of the SLCWRF treatment plant was not undertaken because the site already supported a cogeneration system that used a renewable energy source, biogas, to generate electricity. The project was moved to the Phase II detailed site evaluation for further consideration. During Phase II, the Consultant Team evaluated optimizing the use of the plant’s biogas production with the existing cogeneration system in addition to new generation options.

4.7 Summary of Phase I Evaluation and Site Prioritization

The Phase I evaluation process conducted an initial screening of 151 sites. These included 50 sites for solar PV potential (35 water storage facilities, 10 buildings, and 5 open land parcels); 95 sites for hydroelectric potential (51 PRVs, 44 water rights hydropower applications sites, four canal drop structures and one pipeline); two sites for wind power potential; three sites for wastewater heat recovery potential; and one site for cogeneration potential. This preliminary screening and evaluation identified the technical generation potential of different renewable energy technologies at specific sites owned and operated by DPU. Of the original 151 sites identified, 42 sites were ultimately fully evaluated using the matrix spreadsheet.

The results show that sites with a score of 80 or higher generally had the ability to both generate at a higher capacity and offset either all or a portion of on-site DPU loads. The exceptions were four PRV sites that were not located adjacent to DPU loads but have the potential to generate at a higher capacity than other sites and possibly interconnect at a distribution line. Sites with mid-range scores between 60 and 79 were generally sites that either had a low generation potential but are located adjacent to a DPU load, or generate at a moderate capacity when compared to other sites and must interconnect to a distribution line nearby or potentially a short distance from the site. Sites with a low range score of less than 60 were generally sites with greater environmental impact potential or exhibited site constraints that may render the site more difficult to develop. Table 4-4 illustrates the results of the Phase I scoring. Appendix A provides the complete Phase I evaluation matrix input and results.

Table 4-4. Phase I Evaluation Scores

Ranking	Site Name	Technology	Site Type	Capacity (kW)	Annual Energy (kWh)	Total Points
1	Mountain Dell Dam	Hydroelectric	Surface Water	410	2,370,536	98
2	Terminal Reservoirs/Park Reservoir	Solar PV	Water Tank/Reservoir - Roof Mount	1,562	2,280,520	92
3	Morris Reservoir	Solar PV	Water Tank/Reservoir - Roof Mount	176	256,960	90
4	South Lift	Solar PV	Open Parcel - Ground Mount	299	436,540	90
5	15th East Reservoir	Solar PV	Water Tank/Reservoir - Roof Mount	290	423,400	86
6	Salt Lake City Sports Complex	Solar PV	Buildings - Roof Mount	187	273,020	86
39	Military Reservoir	Solar PV	Water Tank/Reservoir - Roof Mount	256	373,760	86
7	B35-R18	Hydroelectric	PRV	422	1,539,757	85
8	B11-R13	Hydroelectric	PRV	292	1,064,622	85
9	C41-R20	Hydroelectric	PRV	281	1,025,114	85
10	Victory Road Reservior	Solar PV	Water Tank/Reservoir - Roof Mount	248	362,080	85
11	Concord Lift	Solar PV	Open Parcel - Ground Mount	79	115,340	85
12	Baskin Reservoir	Solar PV	Water Tank/Reservoir - Roof Mount	395	576,700	84
13	Wilson Reservoir	Solar PV	Water Tank/Reservoir - Roof Mount	241	351,860	82
16	B6-R73	Hydroelectric	PRV	266	970,091	80
17	East Bench Tanks	Solar PV	Water Tank/Reservoir - Roof Mount	38	55,480	79
18	G35-CR53	Hydroelectric	PRV	36	131,639	78
14	6200 S. Well	Solar PV	Open Parcel - Ground Mount	63	91,980	76
19	Tanner Reservoir	Solar PV	Water Tank/Reservoir - Roof Mount	67	97,820	76
20	Granite Oaks Tank/Telford Reservoir	Solar PV	Water Tank/Reservoir - Roof Mount	54	78,840	76
21	Mt Opympus Tanks	Solar PV	Water Tank/Reservoir - Roof Mount	45	65,700	76
22	Eastwood Tanks	Solar PV	Water Tank/Reservoir - Roof Mount	14	20,440	76
23	Sorenson Multicultural and Unity Fitness Center	Solar PV	Buildings - Roof Mount	58	84,680	76
24	SLCDPU Buildings	Solar PV	Buildings - Roof Mount	57	83,220	76
25	Greenfield Village	Solar PV	Open Parcel - Ground Mount	51	74,460	76
26	Marcus Reservoir	Solar PV	Water Tank/Reservoir - Roof Mount	190	277,400	75
27	Capital Hill Tanks	Solar PV	Water Tank/Reservoir - Roof Mount	45	65,700	75
28	G38-CR57	Hydroelectric	PRV	17	62,052	74
29	D69-R40	Hydroelectric	PRV	63	228,660	70
30	C1-R74	Hydroelectric	PRV	54	196,973	70
31	A23-R5	Hydroelectric	PRV	59	216,797	67
32	Ensign Downs Lower Tank	Solar PV	Water Tank/Reservoir - Roof Mount	105	153,300	67
15	D74-DV1	Hydroelectric	PRV	359	1,310,352	65
33	Big Spill	Hydroelectric	Surface Water	15	65,520	60
34	Smith & Loveless	Solar PV	Open Parcel - Ground Mount	85	124,100	49
35	McEntire Reservoir	Solar PV	Water Tank/Reservoir - Roof Mount	142	207,320	45
36	13th East Reservoir	Solar PV	Water Tank/Reservoir - Roof Mount	114	166,440	45
37	F78-CR28	Hydroelectric	PRV	41	151,340	42
38	Tavaci Tank	Solar PV	Water Tank/Reservoir - Roof Mount	47	68,620	42
39	Salt Lake City Water Reclamation Facility	Cogeneration				
40	Salt Lake City Water Reclamation Facility	WWHR	Treated Wasetwater Effluent			
41	500 South Trunkline	WWHR	Wastewater Conveyance Main			
42	West Temple Trunkline	WWHR	Wastewater Conveyance Main			

As a result of the Phase I screening evaluation, 42 sites were ranked and presented to DPU for review. After consultation with the DPU Steering Committee, 19 sites were selected for more detailed evaluation in Phase II, as shown in Table 4-5.

Table 4-5. Renewable Energy Projects Selected for Phase II Evaluation

Site Name	Technology
Terminal and Park Reservoirs	Roof-mounted Solar PV
Morris Reservoir	Roof-mounted Solar PV
15th East Reservoir	Roof-mounted Solar PV
Victory Road Reservior	Roof-mounted Solar PV
Baskin Reservoir	Roof-mounted Solar PV
Wilson Reservoir	Roof-mounted Solar PV
Sorenson Fitness Center	Roof-mounted Solar PV
DPU Campus	Roof-mounted Solar PV
South Lift Station	Ground-mounted Solar PV
Concord Lift Station	Ground-mounted Solar PV
6200 S. Well	Ground-mounted Solar PV
Greenfield Village Well	Ground-mounted Solar PV
Mountain Dell Dam	Hydroelectric
PRV Station B35-R18	Hydroelectric
PRV Station B11-R13	Hydroelectric
PRV Station C41-R20	Hydroelectric
PRV Station D74-DV1	Hydroelectric
SLCWRF	Biogas Cogeneration
West Temple Trunkline	Wastewater Heat Recovery

5.0 PHASE II SITE-SPECIFIC EVALUATIONS

The Phase I evaluation was designed to filter potential renewable projects into a smaller set of projects that were subjected to a site-specific technical assessment. A total of 19 project sites (12 solar sites, five hydroelectric sites, one wastewater heat recovery site, and one cogeneration site) were evaluated as part of the Phase II Site-Specific Evaluations.

5.1 Overview of Methodology

The Phase II evaluation of the 19 renewable energy project sites was broken down into three sequential assessments. The first, a detailed site assessment, was conducted by Sunrise Engineering, Carollo Engineers, and Utah Clean Energy. The site evaluation was undertaken in recognition of the fact that even though a site may exhibit favorable generation potential in Phase I, structural considerations, environmental conditions, geological characteristics, interconnection access, and permitting and zoning limitations may preclude development of a renewable energy project at the location.

Each site was visited by team members and subjected to a detailed evaluation of its technical capability to support a renewable project. The evaluation criteria and scoring range were developed by the Consultant Team in consultation with the DPU Steering Committee.

The Consultant Team understood DPU was seeking both a quantitative and qualitative evaluation and comparative assessment of renewable energy project sites. A scoring and ranking system was created by the Consultant Team to allow for a consistent and objective ranking and comparative analysis of the diverse range of renewable energy technologies and sites. Assessment of the viability of each renewable energy project was conducted on the basis of six categories covering site compatibility, generation potential, interconnection and permitting requirements, zoning standards, and sustainability characteristics. Each category was scored on the basis of two to six criteria that were assigned a score using a 0 to 5 scale, with five being the highest score. Recognizing that some factors are more important for success than others, the scorecard results were tabulated and input into a spreadsheet tool that assigned a percentage weight to each criteria and each category, and calculated a final weighted score of 0 to 5 for each project. The weighted score for each site was then converted to a 100-point scale. Table 5-1 shows the detailed site evaluation criteria by evaluation category.

5.2 Solar PV

Twelve solar PV sites were selected for the Phase II detailed site evaluation. These project sites are provided in Table 5-2.

5.2.1 Detailed Site Evaluation

Each solar site was evaluated using a four step process: data collection and site analysis, preliminary PV array layout, capacity and generation estimation, and scoring and ranking of projects.

Table 5-1. Detailed Site Evaluation Criteria and Scoring

Evaluation Category	Criteria	Scoring Weight
Site	• Compatibility with the existing site use. • Compatibility with existing infrastructure. • Site access for construction and interconnection activities. • Obvious topographical, geologic, property, environmental constraints. • Potential public safety risk. • Conflicts with established land uses and potential of being a public nuisance.	30%
Interconnection	• Direct access to DPU load or the distribution system. • Complexity and costs of interconnection requirements.	15%
Zoning	• Extent to which the development of a renewable energy project would be compatible with existing zoning ordinances. • Whether those ordinances could potentially be changed if necessary.	15%
Permitting	• Required no. of permits. • Complexity of a permitting process.	10%
Generation	• Quality of the renewable energy resource. • Potential to increase DPU energy system resiliency to power outages and reliability. • Contribute to offsetting electricity load at the site. • Contribute to offsetting DPU's largest and most critical end use loads.	20%
Sustainability	• Contribution to meeting Salt Lake City's renewable energy goals. • Reducing reliance on fossil fuel generated electricity. • Contribute to meeting Salt Lake City's GHG goals. • Whether the project will enhance opportunities to educate Salt Lake City residents and improve public perception of DPU and Salt Lake City's commitment to clean energy and air. • Potential to enhance opportunities for local clean energy vendors and jobs. • Demonstrates leadership in the deployment of distributed renewable energy systems in Salt Lake City and help remove regulatory or policy barriers.	10%

Data collection consisted of a site visit to each of the 12 solar sites. Site assessments included the evaluation of site characteristics including current use of the site, structural design issues, available space, shading obstacles, consideration of potential interconnection options, zoning requirements, ease of permitting, a more detailed evaluation of generation potential strategies, and anecdotal information obtained from speaking with DPU employees.

Radiation data in the Salt Lake City area was also collected and a shading analysis was performed at each site using a Solar Pathfinder instrument, which takes into account the site latitude and how an obstruction may cause shading at a site over a calendar year.

Table 5-2. Solar PV Sites Evaluated in Phase II

Site Name	Site Type	Installation Type
Terminal and Park Reservoirs	Water Tank/Reservoir	Roof Mount
Morris Reservoir	Water Tank/Reservoir	Roof Mount
15th East Reservoir	Water Tank/Reservoir	Roof Mount
Victory Road Reservior	Water Tank/Reservoir	Roof Mount
Baskin Reservoir	Water Tank/Reservoir	Roof Mount
Wilson Reservoir	Water Tank/Reservoir	Roof Mount
Sorenson Fitness Center	Building	Roof Mount
DPU Campus	Building	Roof Mount
South Lift Station	Open Parcel	Ground Mount
Concord Lift Station	Open Parcel	Ground Mount
6200 S. Well	Open Parcel	Ground Mount
Greenfield Village Well	Open Parcel	Ground Mount

The interconnection assessment evaluated whether there was direct access to DPU loads or electrical distribution and the technical feasibility of interconnection. Each of the solar sites evaluated had a nearby or adjacent DPU service load and potential interconnection point to the electrical distribution system. It was also found that each of the potential sites would require either the upgrade or installation of a pad-mount transformer to facilitate a tie-in to the distribution system.

Five of the solar sites would require a zoning ordinance change in order to install solar PV arrays (Baskin Reservoir, Concord Lift Station, Morris Reservoir, Terminal and Park Reservoirs, Victory Road Reservoir), however, it is not anticipated that an ordinance change would result in a lengthy protracted process. The other seven sites are already zoned for solar array installation.

It is anticipated that a conditional use permit would be required for each site and would be relatively simple to obtain for at least 10 of the 12 potential sites. Two of the sites (Concord Lift Station and Wilson Reservoir) may be more difficult to permit due to adjacent property owner access issues (Concord Lift Station) and the potential to impair scenic vistas (Wilson Reservoir).

A preliminary PV array layout was developed to maximize the number of PV modules that may reasonably be installed at each site. Based on the PV array layout, the potential first year of electricity generation for each site was estimated. The accumulative output for 25 years was also estimated using a module degradation rate of 0.6 percent per year. Table 5-3 provides a summary of the capacity and generation estimates at each site.

5.2.2 Scoring and Ranking of Solar PV Projects

Scores for each of the 12 solar sites were developed following the evaluation of each site. Based on the results of the on-site evaluation of siting characteristics, generation potential, ease of interconnection with load and/or the grid, permitting and zoning, and consideration of additional

sustainability, criteria scores for each solar site were tabulated and ranked relative to the other potential solar PV projects. Table 5-4 provides a summary of the scoring and ranking of each site.

Table 5-3. Solar PV Capacity and Generation Estimates

Site Name	Number of Panels	AC Capacity (kW)	Average Annual Generation (kWh)
Terminal & Park Reservoirs	15,853	3,488	4,489,218
Morris Reservoir	1,244	274	360,918
15th East Reservoir	1,244	274	334,918
Victory Road Reservoir	2,029	446	556,634
Baskin Reservoir	1,908	420	514,706
Wilson Reservoir	1,161	255	335,868
Sorensen Fitness Center			
DPU Campus			
South Lift Station	1,312	289	380,608
Concord Lift Station	288	63	75,461
6200 South Well	220	48	49,644
Greenfield Village Well			

Table 5-4. Solar PV Project Scoring and Ranking

Project Site	Technology	Capacity (kW)	Score
Sorenson Fitness Center	Building Rooftop PV	NA	85.6
DPU Campus	Building Rooftop PV	NA	85.4
15th East Reservoir	Roof Mounted PV	274	84.6
South Lift Station	Ground Mounted PV	289	83.3
Wilson Reservoir	Roof Mounted PV	255	71.9
6200 S. Well	Ground Mounted PV	48	68.6
Greenfield Village Well	Ground Mounted PV	NA	67.3
Morris Reservoir	Roof Mounted PV	274	67.2
Victory Road Reservoir	Roof Mounted PV	446	66.3
Terminal & Park Reservoirs	Roof Mounted PV	3,488	65.0
Baskin Reservoir	Roof Mounted PV	420	62.6
Concord Lift	Ground Mounted PV	63	50.6

5.3 Hydroelectric Generation

Five of the 95 hydroelectric sites evaluated in Phase I were selected for a more detailed Phase II evaluation. The selected sites include one conventional hydroelectric site at Mountain Dell Dam just upstream of the Parley's Water Treatment Plant, and four PRV sites located within the water distribution system, as shown in Table 5-5.

Table 5-5. Hydroelectric Sites Evaluated in Phase II

Site Name	Site Type
Mountain Dell Dam	Surface Water
PRV Station B35-R18	Pressure Reducing Valve
PRV Station B11-R13	Pressure Reducing Valve
PRV Station C41-R20	Pressure Reducing Valve
PRV Station D74-DV1	Pressure Reducing Valve

5.3.1 Detailed Site Evaluation

Evaluation of each hydroelectric site was accomplished in three steps: collection and analysis of flow data, capacity and generation estimation, and scoring and ranking of projects.

Data collection consisted of a site visit to each of the five hydroelectric sites. Site assessments included the evaluation of physical site characteristics (site usage, available space), consideration of potential interconnection strategies, and anecdotal information obtained from speaking with DPU employees. Relevant historical flow data was also provided by DPU for each site. The historical flow data was utilized to develop a flow duration curve providing data on the probability of flow magnitudes based on historical data.

The technical feasibility of interconnection was evaluated at each potential hydroelectric site whether there was direct access to DPU loads or to electrical distribution lines. The proximity and ease of interconnection was preliminarily evaluated including the identification of additional infrastructure that may be necessary. Only the Mountain Dell Dam site had an adjacent DPU service load (Parley's Water Treatment Plant). PRV stations B11-R13, B35-R18, and C41-R20 are each located adjacent to a potential interconnection point to the electrical distribution system. While there are high voltage transmission lines located adjacent to D74-DV1 (adjacent to the I-80 and I-215 interchange), there is no nearby access to the three-phase distribution system. Therefore, construction of a three-phase distribution line would be required to develop hydroelectric power at D74-DV1. Each of the potential sites would require installation of a pad-mount transformer to facilitate a tie-in to the distribution system.

Zoning ordinances in the vicinity of the PRV sites currently allow for utility buildings or structures and transmission wire lines, pipes, or poles. Therefore, it is not anticipated that an ordinance change would be required.

It is anticipated that DPU would be required to either file a notice of intent to construct a qualifying conduit hydropower facility (QCHF), or complete the Conduit Exemption process with the Federal Energy Regulatory Commission (FERC) to complete a project at the Mountain Dell Dam site. For the PRV station sites (B11-R13, B35-R18, and D74-DV1) filing a notice of intent to construct a QCHF with FERC would be required.

Based on a more detailed analysis of flow and head conditions at each hydroelectric site, the capacity and average annual generation at each site was estimated and provided in Table 5-6.

Table 5-6. Hydroelectric Capacity and Generation Estimates

Site Name	Capacity (kW)	Average Annual Generation (kWh)
Mountain Dell Dam	260	690,000
PRV Station B35-R18	220	1,145,000
PRV Station B11-R13	190	773,000
PRV Station C41-R20	170	872,000
PRV Station D74-DV1	300	700,000

The most technically feasible hydroelectric development at Mountain Dell Dam site would be a facility installed upstream of the Parley's Water Treatment Plant at the toe of Mountain Dell Dam, which utilizes the flow and head from Mountain Dell Dam only. Based on our assessment of flow data provided for the Little Dell site and our evaluation of the pre-design report prepared by Alpha Engineering and RB&G Engineering, Inc. (2014), the Consultant Team concluded the results of the report were not reasonable or practical. If DPU still wishes to operate a hydroelectric facility utilizing the head and flow from the Little Dell Bypass, a more detailed evaluation of the hydrology conditions is warranted.

Each of the four PRV stations are technically feasible but would require expansion or reconstruction of the existing vaults to accommodate hydroelectric equipment and controls. It would also be necessary to provide measures to ensure uninterrupted flow to the distribution system in the event the hydroelectric equipment is offline.

In the case of PRV stations B11-R13 and D74-DV1, each vault could be expanded or reconstructed with minimal or no disturbance to adjacent traffic conditions. However, both B35-R18 and C41-R20 are located in vaults directly beneath the roadway. While sites D74-DV1, B35-R18, and C41-R20 have flatter topography directly adjacent to the vault, site B11-R13 is located along a slope which could require significant slope stabilization measures during construction of a vault expansion.

If DPU desires to develop the hydroelectric potential at the PRV stations, it is recommended the sites be metered to collect flow data for at least a year to understand how the flow data from the model may vary from what is actually occurring on-site. This would ensure a more accurate sizing of potential turbine and generator equipment.

5.3.2 Scoring and Ranking of Hydroelectric Projects

For each of the five hydroelectric project sites that underwent a detailed, on-site assessment, scoring was completed based on siting characteristics, generation potential, ease of interconnection with load and/or the grid, permitting and zoning, and consideration of additional sustainability criteria. The scores of each hydroelectric site were tabulated and sites ranked relative to the other projects sites. The Mountain Dell Dam site scored the highest primarily due to its generation potential, proximity to existing load, and interconnection access. A summary of the scoring and ranking results is provided in Table 5-7.

Table 5-7. Hydroelectric Project Scoring and Ranking

Project Site Name	Technology	Capacity (kW)	Score
Mountain Dell Dam	Conventional Hydroelectric	260	80.3
B11-R13	Reverse Pump Turbine	190	58.3
D74-DV1	Reverse Pump Turbine	300	55.4
B35-R18	Reverse Pump Turbine	220	53.8
C41-R20	Reverse Pump Turbine	170	53.8

5.4 Wastewater Heat Recovery

Based on the results of the Phase I preliminary evaluation, the West Temple wastewater heat recovery site located adjacent to DPU Campus was determined to be technically feasible and selected for further evaluation in Phase II.

5.4.1 Detailed Site Evaluation

Data collection consisted of a site evaluation of physical site characteristics (site usage, available space), consideration of potential usage strategies, and anecdotal information obtained from speaking with DPU employees. Relevant historical sewer flow and temperature data were also provided by DPU. The historical data was utilized to understand the energy potential associated with the site.

The proposed wastewater heat recovery facility project would utilize a heat exchanger to extract heat from wastewater flowing in the sewer trunkline along West Temple, adjacent to DPU's administration campus. The main office currently utilizes four forced air gas units to heat the facility. Wastewater heat recovery technology would utilize a portion of the flow from the adjacent sewer

line, recover heat from the water, and then return it to the sewer line. Where the flow line of the sewer line is approximately 15-feet below street level, water would be screened and pumped to a heat exchanger where heat would be transferred to a water/glycol mixture. The water/glycol mixture would then run to a heat pump which would be connected to the existing forced air system. The heat pump would utilize electric energy to boost the heat potential to the range typically required for a forced air heating system.

The peak output from the system would be approximately 737 MBH (737,000 BTU/hour) utilizing a 156-kW heat exchanger with a 60-kW heat pump. Based on the annual heating profile provided by DPU, it appears a wastewater heat recovery system would meet all the heating requirements for DPU's main office from March through October, and meet a percentage of the need during peak winter heating (January—50 percent, February—60 percent, November—70 percent, December—50 percent). The utility service that would be avoided is natural gas, while additional electricity service is required to operate the heat pump.

5.4.2 Scoring of Wastewater Heat Recovery Site

Scoring for this project considered the viability of the site to support wastewater heat recovery technology, potential to offset natural gas, interconnection with existing heating system load, permitting and zoning, and consideration of additional sustainability criteria. The West Temple Project was not scored because it is a demonstration project that will provide an opportunity to demonstrate the viability of this technology, learn about how it could be used throughout Salt Lake City, and serve as an important educational resource.

5.5 SLCWRF Biogas Cogeneration

The Salt Lake City Water Reclamation Facility was selected to be evaluated in Phase II based on the fact that the site already had a cogeneration system using a renewable energy source—biogas—to generate electricity.

Carollo Engineers prepared a technical memorandum which provides details of the site evaluation, analysis of alternative technologies, and generation assessment. The technical memorandum is included as Appendix B.

5.5.1 Detailed Site Evaluation

Currently at the SLCWRF, digester gas is collected and used to fuel a boiler for digester heating needs or cleaned prior to combustion in two 700-kW engine generators to generate electricity to serve on-site load. Electricity generated through the combustion of digester gas offsets a portion of the power that must be purchased from the local energy utility. Any digester gas in excess of what can be used in the engine generators or boiler is destroyed by flare.

The Consultant Team evaluated two options for maximizing the generation of electricity from biogas at SLCWRF: using the existing generators to combust more biogas through operational

changes, or replacing the generators with newer equipment or other technologies. Based on an analysis of current gas productions, as well as digester gas production projections, the following alternatives were developed and evaluated.

- Alternative 1—Use existing cogeneration engines, run one engine with no natural gas supplementation.
- Alternative 2—Use existing cogeneration engines, run two engines with no natural gas supplementation.
- Alternative 3—Use existing cogeneration engines, run two engines with natural gas supplementation.
- Alternative 4—Replace existing engines with a new engine.
- Alternative 5—Replace existing engines with new micro-turbine.
- Alternative 6—Replace existing engines with new fuel cell.

Each of the alternatives was evaluated based on digester gas production from two treatment process configurations, the current wastewater treatment process, and a biological nutrient removal (BNR) process, which may be required by federal water quality standards in the future.

The results of the detailed analysis as well as recommendations are provided in the complete technical memorandum in Appendix B.

5.5.2 Scoring of SLCWRF Cogeneration Site

Scoring the site was based on the of viability of the site to support generation of renewable electricity, potential to offset natural gas consumed, interconnection requirements, permitting and zoning, and consideration of additional sustainability criteria. The project site scored high due to the existence of the biogas-cogeneration system already in operation including the supporting infrastructure. On a 100 point scale, the project's score was 92.9.

5.6 Summary of Phase II Detailed Site Evaluation Scoring and Ranking

Nineteen project sites went through the Phase II detailed site assessment and were scored according to six categories using 20 criteria covering site, generation potential, interconnection and permitting requirements, zoning standards, and sustainability characteristics. Each criterion was assigned a score of 0 to 5. Scores were then tabulated and input into a spreadsheet tool that calculated a weighted average score based on 100-point scale. The higher the score the more likely the Consultant Team considered the project to be successful in meeting DPU's energy and environmental objectives. Table 5-8 includes all 19 projects ranked from highest to lowest based on the score each project site received. Appendix C provides the detailed Phase II scoring and ranking matrix input and results.

Table 5-8. Detailed Site Evaluation Scoring and Ranking

Site Name	Technology	Capacity (kW)	Scores
SLCWRF	Biogas Cogeneration	1,400	92.9
Sorenson Fitness Center	Building Solar PV	-	85.6
DPU Campus	Building Solar PV	-	85.4
15th East Reservoir	Roof-mounted Solar PV	274	84.6
South Lift Station	Ground-mounted Solar PV	289	83.3
West Temple Trunk-line	Wastewater Heat Recovery	NA	NA
Mountain Dell Dam	Hydroelectric	260	80.3
Wilson Reservoir	Roof-mounted Solar PV	255	71.9
6200 South Well	Ground-mounted Solar PV	48	68.6
Greenfield Village Well	Ground-mounted Solar PV	-	67.3
Morris Reservoir	Roof-mounted Solar PV	274	67.2
Victory Road Reservoir	Roof-mounted Solar PV	446	66.3
Terminal & Park Reservoirs	Roof-mounted Solar PV	3,488	65.0
Baskin Reservoir	Roof-mounted Solar PV	420	62.6
PRV Station B11-R13	Hydroelectric	190	58.3
PRV Station D74-DV1	Hydroelectric	300	55.4
PRV Station B35-R18	Hydroelectric	220	53.8
PRV Station C41-R20	Hydroelectric	170	53.8
Concord Lift Station	Ground-mounted Solar PV	63	50.6

The Consultant Team met with the DPU Steering Committee and used the ranked scores and information from the detailed site evaluations as the basis for developing a short list of projects that would undergo additional economic analysis and regulatory assessment. The Steering Committee and Consultant Team then selected a representative cross section of six projects from the 19 ranked projects. These six projects were advanced to a more comprehensive evaluation. The projects selected for additional assessment are listed in Table 5-9.

Table 5-9. Renewable Energy Projects Selected for Economic and Regulatory Analysis

Site Name	Technology	Capacity (kW)	Scores
SLCWRF	Biogas Cogeneration	1,400	92.9
15th East Reservoir	Roof-mounted Solar PV	274	84.6
West Temple Trunkline	Wastewater Heat Recovery	NA	NA
Mountain Dell Dam	Hydroelectric	260	80.3
Terminal & Park Reservoirs	Roof-mounted Solar PV	3,488	65.0
PRV Station B11-R13	Reverse-pump turbine	190	58.3

6.0 REGULATORY ASSESSMENT—RATE SCHEDULE ANALYSIS

The regulatory assessment addressed tariff options for each of the six renewable energy project sites. The purpose was to identify and make recommendations for the most appropriate rate schedule for the site to maximize the economic benefit of the renewable energy project. Four categories and six rate tariffs were evaluated by the Consultant Team; partial requirements tariffs designed to provide supplementary, backup, and maintenance power to customers who obtain any part of their regular electric requirements from self-generation; tariffs provided by RMP as required by the Public Utilities Regulatory Policy Act (PURPA) to promote greater use of domestic energy and renewable energy;[6] a new tariff designed to serve large customers who would like to build renewable energy projects or purchase renewable energy from third parties and deliver the power to their facilities through RMP's distribution system; and net metering tariffs that allow customers with on-site renewable energy facilities to connect to the electrical grid and receive credit for excess electricity that is produced, but not consumed, on-site. Table 6-1 provides a description of the Rate Tariffs Evaluated.

Table 6-1. Rate Tariffs Evaluated

Tariff Schedule	Description
Electric Service Schedule 31	This schedule is for customers who have on-site generation capacity and require backup and maintenance power. Schedule 31 anticipates that customers will be reducing or eliminating usage of utility power the majority of the time and does not provide credits for electricity production in excess of usage, nor does it allow for resale of excess electricity.
Electric Service Schedule 37	Schedule 37 is available to owners of certified small Qualifying Facilities (QFs): either cogeneration facilities with a design capacity of 1-MW or less, or small power production facilities with capacity of 3-MW or less. Prices for the sale of power through this schedule are published, "standard offer" rates. QFs enter into a written power sales contract with RMP based on the published prices.
Electric Service Schedule 38	Schedule 38 is available to owners of certified cogeneration QFs with capacity greater than 1-MW or small power production QFs with capacity greater than 3-MW. Large QFs negotiate pricing and contract terms directly with RMP.
Electric Service Schedule 32	Customers who want to develop their own renewable energy facilities may contract for the delivery of the electricity from their own off-site renewable projects to their facilities through this tariff. Under this tariff the customer must contract for more than 2-MW of electricity delivery and is responsible for paying all interconnection and integration costs to RMP.
Electric Service Schedule 135 – Net Metering	Schedule 135 is intended primarily to allow an on-site renewable energy project to offset part or all of the customer's own electrical requirements. The customer-generator can aggregate its electrical requirements from multiple meters for the purpose of net metering, as long as all meters are located at or adjacent to the same property. Non-residential facilities can be up to 2-MW.

[6] An owner or operator of a generating facility with a maximum net power production capacity of greater than 1-MW (1,000 kW) may obtain QF status by submitting a "self-certification" (no fee), or by applying for and obtaining FERC certification of QF status (fee required).

6.1 Salt Lake Water Reclamation Facility

The SLCWRF was recently switched from Schedule 9 to Schedule 31, which is Partial Requirements General Service for large customers with more than 1-MW of on-site generation. However, if on-site generation were less than 1-MW, the plant would return to Schedule 9 (General Service, High Voltage).[7] Schedule 31 customers are not eligible for net metering.[8]

The purpose underlying the new "Partial Requirements Service" rate schedule is to set rates such that a customer would pay an equivalent amount under Schedule 31 as they would pay under their general service rate schedule (i.e., Schedule 9) if they did not have on-site generation offsetting their bills. Since DPU has the opportunity to alter the cogeneration process at the reclamation facility, DPU should consider the economics of generation alternatives under Schedule 31 compared to Schedule 9. If on-site cogeneration capacity is less than 1-MW, the facility may revert to Schedule 9 and take backup, supplementary, and maintenance power at Schedule 9 rates.

Finally, DPU could increase use of the existing engines and produce more electricity without upgrading equipment by switching to a rate schedule that allows occasional excess generation. DPU should consider the economics of various technologies according to the rate schedules associated with on-site generation capacity greater than or less than 1-MW (under Schedules 31 and 9, respectively). Neither Schedule 31 nor Schedule 9 allows net metering. However, as a facility taking service under Schedule 31, the SLCWRF may sell excess electricity back to the utility at wholesale "avoided costs" rates using either Schedule 37 (if the capacity sold is less than 1-MW) or Schedule 38 (if greater than 1-MW).

6.2 15th East Reservoir

The 15th East Reservoir is currently receiving electricity through Schedule 6A, a "time of use" schedule that rewards facilities that shift the bulk of their electricity usage to off-peak hours with lower electricity rates during those hours. A substantial portion of the electricity usage at the reservoir appears to be during on-peak hours where Salt Lake City is paying the highest rate. Schedule 6A might not currently be providing the most advantageous rates for this facility. A solar installation will provide electricity primarily during on-peak hours, reducing usage at the reservoir during that time, so Schedule 6A will be a more practical rate schedule for this facility if solar PV is installed.

If a solar PV array is designed to meet existing load and installed at the 15th East Reservoir, the site would be a good candidate for RMP's Schedule 135 Net Metering Tariff. However, net metering does not allow a customer to receive credits in excess of their annual usage, so in order to make the solar project a good candidate for net metering, the size of the system needs to be designed based on the average annual electricity usage at this site (rather than the area available for a solar installation at

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[7] The applicability of Schedule 31 recently changed from an elective rate schedule for customers with specific attributes, to a mandatory rate schedule for customers with more than 1-MW of on-site generation.

[8] Schedule 135 is available to non-residential Schedules 6, 6A, 6B, 8, 10, 15, and 23, which all take service at distribution voltage.

the site). It would be possible to install a larger solar array at the site, however electricity generation from the solar PV would exceed the on-site electricity load, and DPU could not receive net metering credits for electricity generated in excess of the annual usage.

Given that the technical potential for solar generation at this site greatly exceeds on-site electricity usage, DPU could choose to construct a larger solar installation than is necessary to meet electricity needs on-site and instead contract to sell the excess electricity in one of two ways. First, this site could be developed to deliver electricity directly to DPU as one project in a portfolio of DPU-owned renewable projects through the contracting provisions allowed under Electric Service Schedule 32. This tariff was enabled by Senate Bill 12 (SB 12) in 2012 (codified at Utah Code Ann. Section 54-17-801, et seq.). Although customers utilizing Schedule 32 must contract to take more than 2-MW of electricity, the law permits multiple renewable energy facilities with 2-MW of aggregated capacity to deliver electricity to a single contract customer. While the cogeneration facility is technically eligible for Schedule 32, this rate schedule will likely only be advantageous for waste heat projects due to the method by which the charge for demand is calculated.

A solar installation at the 15th East Reservoir could certify as a QF and contract to sell electricity to RMP under Electric Service Schedule 37's "avoided cost" rates. Pricing under Schedule 37 was recently litigated and the newly approved published rates are available up to 25-MW of project capacity until next year, when RMP must update pricing again.

6.3 Mountain Dell Reservoir

The Parley's Canyon Water Treatment Plant is currently receiving electricity through Schedule 6A, a "time of use" schedule that rewards facilities that shift the bulk of their electricity usage to off-peak hours with lower electricity rates during those hours. Electricity usage at Parley's Water Treatment Plant appears to be fairly evenly split between on-peak hours and off-peak hours, and so rate Schedule 6A might not currently be providing the most advantageous rates for this facility if a renewable energy project is not developed on-site.

If the hydroelectric project is developed this site is a good candidate for net metering on Schedule 135. A 260-kW hydroelectric turbine falls under the 2-MW capacity limit allowed through Schedule 135. The hydroelectric turbine would produce more electricity in the summer months: an average of 442 MWh annually during the summer season and 247 MWh annually during the winter season. This seasonality is advantageous for a net-metered facility. Credits for excess generation roll over from month to month and can be used to offset future electricity bills, however, all credits for excess generation are forfeited at the end of the annualized billing period, on March 31st.

6.4 Terminal and Park Reservoirs

There is minimal on-site load at this facility compared to the technical potential of the site, so net metering is not a practical option for this site. A solar facility built to take advantage of the available space could produce a substantial amount of electricity. There are four options available for a solar

facility at the Terminal and Park Reservoirs, two of which are immediately available. A third option, Schedule 32, will be available as soon as the proposed tariff is finalized by the Public Service Commission.

Electric Service Schedule 32 is designed to serve large customers, like DPU, who would like to source a larger portion of their electric service from renewable energy resources than is currently available through RMP. Using Schedule 32, large customers will be able to build or purchase energy from off-site renewable energy projects and pay RMP for the delivery of such electricity to their facilities. Thus, DPU could build a solar facility at Terminal and Park Reservoirs and contract for the delivery of electricity from the Reservoirs to another facility through this tariff. Although solar facilities are technically eligible for Schedule 32, this rate schedule may not be advantageous for solar projects due to the method by which the charge for demand is calculated.

Using Schedule 37, DPU could certify the Terminal and Park Reservoirs as a QF and contract to sell electricity to RMP using "avoided cost" rates available to renewable QFs sized 3-MW and smaller.[9] Since Schedule 37 is only available to small projects (3-MW and under), DPU has a couple of options for this site:

- Certify this facility as a QF, build a 3-MW project, and sell the electricity to the utility under Schedule 37.
- Have two separate project owners develop QF projects, each smaller than 3-MW, in order to take advantage of the full technical potential at the site. A single QF project owner may not build more than one project (of the same technology) within a single mile radius; however, Salt Lake City could work with the Metropolitan Water District of Salt Lake and Sandy (MWDSLS) (the owner of two of the water tanks comprising the facility) to develop two separate QF projects at the Terminal and Park Reservoirs, owned by Salt Lake City and MWDSLS respectively. Both facilities could use the same interconnection point, and it may be possible to operate both QFs as a single facility.

Pricing under Schedule 37 was recently litigated and the newly approved published rates are available to 25-MW of project capacity until next year, when RMP must update pricing again. This option is available now and current prices are provided in Table 6-2.

Table 6-2. Schedule 37 Levelized Prices (Nominal) for Solar PV (Cents per kWh)

	On-Peak Energy Prices		Off-Peak Energy Prices	
	Winter	Summer	Winter	Summer
Fixed Tilt Solar PV	4.013	4.246	3.548	3.781
Tracking Solar PV	4.188	4.420	3.613	3.846

9 For more information about QFs, how to become certified as a QF, and Schedule 37 See Appendix D, "Schedule 37."

Through Schedule 38, the Terminal and Park Reservoirs could certify as a QF and contract to sell electricity to RMP using "avoided cost" rates, available to renewable QFs larger than 3-MW.[10] Unlike Schedule 37, pricing under this schedule is not published; rather, the Commission approved a pricing calculation method that RMP uses to establish "indicative prices" upon request. Pricing and contract terms are then negotiated directly with RMP. Because negotiating pricing with RMP can be a costly and time consuming process, this option, though available to facilities as small as 3-MW, may not be economically feasible for a project smaller than 20-MW. This tariff will be undergoing pricing and process revisions in the coming months.

6.5 PRV Station B11-R13

A 190-kW hydroelectric turbine is proposed to generate electricity using pressure head at an existing PRV in a vault structure. There is no on-site load at this location, so there are a few potential options for using the energy produced at this facility, of which only one is immediately available.

A hydroelectric turbine at this site could certify as a QF and contract to sell electricity to RMP under Electric Service Schedule 37 "avoided cost" rates, available to renewable QFs 3-MW and smaller.[11] Pricing under Schedule 37 was recently litigated and the newly approved published rates are available up to 25-MW of project capacity until next year when RMP must update pricing again. This option is available now and current prices are provided in Table 6-3.

Table 6-3. Schedule 37 Levelized Prices (Nominal) for Baseload Renewable Energy (Cents per kWh)

	On-Peak Energy Prices		Off-Peak Energy Prices	
	Winter	Summer	Winter	Summer
Baseload Renewable Energy	4.589	4.819	3.859	4.089

This site could potentially sell electricity through the contracting provisions enabled under Electric Service Schedule 32. Although customers utilizing Schedule 32 must contract to take more than 2-MW of electricity delivery through Schedule 32, the law permits multiple renewable energy facilities to deliver electricity to a single contract customer. Thus, this site could be one of a portfolio of facilities serving DPU load under Schedule 32.

10 For more information about QFs, how to become certified as a QF, and Schedule 38 See Appendix D, "Schedule 38."

11 For more information about QFs, how to become certified as a QF, and Schedule 37 See Appendix D, "Schedule 37."

7.0 ECONOMIC ANALYSIS OF RENEWABLE ENERGY PROJECTS

The DPU Steering Committee and the Consultant Team identified project opportunities at six sites for further economic and regulatory assessment. This section describes the approach, assumptions and results of the economic analysis for each project.

The economic analysis is performed using an annual cash flow model developed by Energy Strategies. The model looks at the economic viability of each project by quantifying the net present value (NPV) of the cost of utility service. The cost of utility service measures the cash flow throughout the life of the project, compared to a business-as-usual (BAU) case where DPU continues to receive utility service from either RMP or Questar. If the NPV is negative then the project is economical, i.e., the costs producing electricity or savings of natural gas due to the renewable energy project is less than utility service over the life of the project.

The model also estimates the levelized cost of power and avoided GHG emissions for each project compared to utility service from RMP and Questar. The economic model also accounts for increases and decreases in the following measures versus the relevant business as usual scenario:

- On-site generating capacity, kW
- Overnight capital, 2014$ millions
- Average annual generation, MWh
- Non-fuel operating expense, 2014$ millions
- As modeled assuming $0 per MT$CO_2$e compliance cost
- Sensitivity analysis at $25 and $50 per MT$CO_2$e compliance cost

A single power generation technology was evaluated for each of four sites proposed for renewable energy development: 15th East Reservoir, B11-R13, Mountain Dell Dam, and Terminal and Park Reservoirs. Four new power generation technologies were evaluated for the fifth site, the SLCWRF. An economic analysis was also conducted for the 1530 South West Temple wastewater heat recovery project but it was based on natural gas saved.

The dollar value assigned to generation is a key assumption. For all but two options, it is assumed that generation would offset purchases of power from RMP and the value of the generation is based on current prices in the electric service schedule that applies to each site.

In the cases of the PRV station B11-R13 and Terminal and Park Reservoirs, generated power exceeds site requirements and is assumed to be sold back to RMP under the Schedule 37 rate. In addition, a sensitivity analysis was conducted on these two sites to evaluate the economic feasibility of those projects if DPU were able to receive credit for excess generation and use it to offset DPU electricity bills at other locations.

7.1 SLCWRF Biogas Cogeneration Site

The SLCWRF biogas cogeneration site is located at Redwood Road and approximately 2000 North in Salt Lake City. Cogeneration already exists at the SLCWRF, where biogas is burned to run two 700-kW engines. The Phase II detailed site evaluation found that the cogeneration system is operating at 48 percent of its nameplate capacity, and generates an average of 5,230 MWh per year to meet the SLCWRF's annual load of 10,858 MWh. In practice, the SLCWRF is running a single engine and consuming 68 percent of the 97,637 MMBtu of biogas produced at the treatment plant each year. The remaining biogas is either consumed as boiler fuel or flared. Five cogeneration options were evaluated for the SLCWRF. Cogeneration capacity estimates varied from 666-kW to 1400-kW for the alternatives evaluated.

Two of the alternatives used operational changes to maximize the use of the two existing 700-kW reciprocating engines. The first alternative evaluated running the engines at a capacity factor high enough to utilize all the biogas produced at the treatment plant. The second alternative assumed the engines were run at their maximum operating capacity which would require the biogas be supplemented with natural gas. The other three options evaluated included replacing the existing engines with a new 1,426-kW reciprocating engine, a 1,000-kW micro-turbine, or 1,400-kW fuel cells. Each of the five power generation technologies considered were also evaluated under two wastewater treatment process scenarios: 1) current process (primary clarification, trickling filters, aeration basins, secondary clarifiers, and solids digestion); and 2) biological nutrient removal process.

To the extent cogeneration at the SLCWRF is currently being limited to one engine, there appears to be an economic opportunity to lower the cost of electricity service supplied to the plant by operating both existing engines using biogas and natural gas as fuels.

If the two existing 700-kW engines are run utilizing only the biogas produced by the treatment plant, DPU would reduce NPV of utility service by $1.458 million over the 20-year life of the project, compared to continuing to receive the same level of service from RMP. If a cost of carbon of $25/MTCO$_2$e or $50/MTCO$_2$e is assumed in the cash flow analysis, then NPV of the economic benefits of the project increase to $2.0 million and $2.5 million respectively.

Running both engines at the capacity factor they are designed to operate at would require utilizing all of the biogas produced at the plant and additional purchase of supplemental natural gas service from Questar. Still, even under this scenario, operating the cogeneration engines to supply electricity to the site proved to be more economical compared to purchasing the equivalent amount of power from RMP. Doing so would reduce NPV of electricity service to the SLCWRF by $243,000 over the 20-year life of the project. If a cost of carbon of $25/MTCO$_2$e or $50/MTCO$_2$e is assumed in RMP's electricity rates, then NPV of the economic benefits of the project increases to $697,000 and $1.12 million respectively.

Table 7-1. Technologies Evaluated For Salt Lake City Water Reclamation Facility

Project Site	Type of Power Technology	Effective Generation Capacity	RMP Electricity Service Schedule	Total Fuel Consumed	Digester Gas Available	Natural Gas Consumed	Average Annual Generation
		kW		MMBTU	MMBTU		MWh
Salt Lake City Water Reclamation Facility	Existing Recip (Run 1)	1,320	RMP 31 (9)	66,151	97,637	-	
	Existing Recip (Run 2 no NG)	1,320		97,128		-	2,553
	Existing Recip (Run 2 with NG)	1,320		111,818		14,181	3,642
	New Recip	1,390		88,333		-	3,855
	Microturbine	844		77,457		-	1,124
	Fuel Cell	1,330		94,582		599	5,187
Salt Lake City Water Reclamation Facility Biological Nutrient Removal	Existing Recip (Run 1)	1,320	RMP 31 (9)	61,651	59,672	1,979	
	Existing Recip (Run 2 with NG)	1,320		111,818		52,146	4,130
	New Recip	827		58,111		289	671
	Microturbine	562		60,816		1,562	-506
	Fuel Cell	855		71,555		11,883	1,964

Moreover, both approaches would result in a meaningful reduction of GHG emissions compared to the current operations where one engine is operated. In the case where both engines are operated based on the available biogas supply from the plant, GHG emissions will be reduced by 1,558 tons, or about 6 percent of DPU's estimated CO_2 emissions emitted from the consumption of electricity and natural gas. Burning all available biogas plus supplemental natural gas to maximize output of the cogeneration engines will also reduce net GHG emissions compared to the reference case by 1,223 tons.

Replacing the existing engines with new reciprocating engines, micro-turbines, and fuel cells was also evaluated. All scenarios where the existing engines were replaced with new cogeneration technology entail significant incremental investment of capital (between $5 and $12 million), making replacement of the existing engines uneconomical. Even when a value of $50 per $MTCO_2e$ is attributed to GHG emissions, replacing the existing engines with newer generation technology is not justified if lowering the cost of electricity service at the SLCWRF is the objective.

The economic analysis described above assumed that SLCWRF would continue to treat effluent using the current process (primary clarification, trickling filters, aeration basins, secondary clarifiers, and solids digestion). If the SLCWRF is required to implement a biological nutrient removal process, this will significantly lower the amount of biogas produced and negatively impact the economic value of all cogeneration opportunities at the SLCWRF. However, the SLCWRF can continue to

operate the existing biogas cogeneration engines, and maximize their use through operational changes, until required to switch to a biological nutrient removal process.

Table 7-2. Salt Lake City Water Reclamation Facility NPV of the Cost of Utility Service

Project Site	Type of Power Technology	Overnight Capital	Non-Fuel Operating Expense	Cost of Utility Service Present Value $Millions			Levelized Cost
		2014$ Millions	2014$ Millions	$0 per MTCO2e	$25 per MTCO2e	$50 per MTCO2e	$ per MWh
Salt Lake City Wastewater Reclamation Facility	Existing Recip (Run 2 No NG)	$0.00	$76.58	($1.46)	($1.996)	($2.533)	$26.50
	Existing Recip (Run 2 with NG)	$0.00	$109.27	($0.27)	($0.697)	($1.120)	$35.50
	New Recip	$9.36	$25.06	$5.94	$5.092	$4.240	$80.00
	Microturbine	$6.73	$65.36	$6.42	$6.169	$5.920	$95.00
	Fuel Cell	$12.09	$328.18	$12.31	$11.181	$10.046	$111.00
	Biological Nutrient Removal						
	Existing Recip (Run 2 with NG)	$0.00	$123.91	$3.11	$3.468	$3.824	$61.50
	New Recip	$8.58	($33.73)	$6.99	$6.785	$6.581	$113.50
	Microturbine	$5.30	$5.88	$5.63	$5.713	$5.795	$108.50
	Fuel Cell	$10.67	$192.50	$12.49	$12.222	$11.953	$149.50

7.2 15th East Reservoir Solar PV Site

The 15th East Reservoir Solar PV site is located at a partially buried concrete reservoir directly east of Rice Eccles Stadium along 500 South in Salt Lake City. The site scored high on the detailed site evaluation and was considered a good candidate site for a future solar PV energy project. The development site would be located on an existing concrete reservoir with open roof space that could support a 274-kW solar PV installation. The majority of the large roof space is relatively new and unobstructed by objects that would create shading impacts. The reservoir is currently surrounded by adequate security fencing, and for the most part is not visible to public at the ground level. The location also has direct access just east of the site to three-phase electrical distribution. There is also on-site access to a DPU load at the University Pump Station and 500 South Well.

A 274-kW solar installation was evaluated at the 15th East Reservoir. A system this size could produce an average of 335,000 kWh of electricity each year. However, electricity meters located at this site report that the on-site load is only 70,000 kWh of electricity each year. This site could support almost five times more solar than is necessary to meet the electricity needs of the on-site facilities. A smaller 25-kW installation at this site could net meter and offset on-site electricity usage however this option was not evaluated. The larger installation would produce more electricity than could be used on-site, and DPU would have to contract to sell the electricity in order to see a financial benefit.

The economic analysis conducted for the 15th East Reservoir site assumed the maximum number of solar panels the site could support would be installed on the roof of the reservoir. The upfront capital costs of the 274-kW solar PV system was estimated to be $920,000, and NPV of operation and maintenance at the site was estimated to be $13,000 per year. Assuming the value of the PV generation at the site would be based on the Schedule 6A rate, NPV of the power generated by the solar array is estimated to exceed the value of electricity supplied by RMP by $426,000 over the 30-year life of the project. Even when a price of carbon of $50/MTCO$_2$e is assumed in the analysis, the project still has an NPV of $200,000 more than service provided by RMP.

However, a smaller, net-metered installation designed to offset on-site electrical usage was not run through the economic analysis. It would likely have a better NPV than the 274-kW project that was evaluated. A lease or a PPA, which was not considered in this evaluation, would allow DPU to take advantage of a federal tax incentive through a third-party ownership structure and could result in a cost reduction of up to 30 percent of. If DPU were to utilize a lease or a PPA, consider optimizing the size of the project based on on-site load, and take advantage of the falling cost of solar, it is likely that this project would offer a better NPV than the cost of utility service over the life of the project.

Table 7-3. 15th East Reservoir NPV of the Cost of Utility Service[12]

Project Site	Type of Power Technology	Use of Generation	Overnight Capital	Non-Fuel Operating Expense	Cost of Utility Service Present Value $Millions			Levelized Cost
			2014$ Millions	2014$ Millions	$0 per MTCO2e	$25 per MTCO2e	$50 per MTCO2e	$ per MWh
15th East Reservoir	Solar PV	Net Metered	$0.920	$0.013	$0.426	$0.314	$0.202	$153.50

7.3 Mountain Dell Dam Hydroelectric Site

The Mountain Dell Dam Hydroelectric site is located at the Parley's Water Treatment Plant along I-80 in Parley's Canyon. A hydroelectric facility would likely be located at the downstream toe of Mountain Dell Dam just upstream of the water treatment facility. The Mountain Dell Dam site was selected by the DPU Steering Committee and Consultant Team for further economic analysis and electric rate assessment because of the following favorable project site characteristics:

1. Sufficient flow to support year-round generation of power.
2. Presence of an existing dam with a water source that employs an energy dissipation valve to burn energy just upstream of the water treatment plant.
3. Available space to develop a facility with the removal of an existing concrete structure (sand separator) and modifications to existing piping.
4. Direct access on-site to water treatment plant facility electrical load and three phase electrical distribution.

[12] Costs and NPV are for a turnkey project without using a PPA or other incentives.

5. Simplified FERC permitting process as power would be a secondary beneficial use of the water, the conduit is owned by Salt Lake City, and the generation capacity is less than 5-MW.

Based on a review of the site and previously performed hydroelectric analyses at Mountain Dell Dam, the Consultant Team concluded there is sufficient space to develop a project at the toe of the dam just upstream of the water treatment plant. The hydroelectric plant would be operated by utilizing water from the Little Dell Reservoir through a 42-inch diameter bypass line 24 hours a day, 365 days a year. The hydroelectric facility would likely utilize a Crossflow-type turbine with an installed capacity of 260-kW and an average annual generation of 690,000 kWh. On-site load at Parley's Treatment Plant is approximately 900 MWh annually, so the electricity produced by a hydroelectric turbine at this location could be used to offset roughly three quarters of electricity used at this site.

Parley's Water Treatment Plant is currently receiving electricity through Schedule 6A. The economic analysis conducted for the Mountain Dell Dam site assumed a 260-kW turbine is installed and generates an annual average 690,000 kWh that is used to offset 75 percent of the load at the Parley's Treatment Plant. Accordingly, the value of the generation from the hydroelectric project was assumed to be the average retail rate for Schedule 6A, which is $11.2772 cents per kWh.
The upfront capital costs of the turbine and power system is estimated to be $1.6 million and the annual average non-fuel operating expenses are estimated to be $19,000 per year. Assuming the value of the generation at the site is based on the Schedule 6A rate, NPV of the power generated by the hydroelectric project is estimated to exceed the value of electricity supplied by RMP by $355,000 over the 50-year life of the project. However, when a price of $50/MTCO$_2$e is assumed in the cash flow analysis, the project's NPV is $228,000 less than service provided by RMP, and this site is considered to be economically viable option for a renewable energy project.

Table 7-4. Mountain Dell Dam Hydroelectric NPV of the Cost of Utility Service

Project Site	Type of Power Technology	Use of Generation	Overnight Capital	Non-Fuel Operating Expense	Cost of Utility Service Present Value $Millions			Levelized Cost
			2014$ Millions	2014$ Millions	$0 per MTCO2e	$25 per MTCO2e	$50 per MTCO2e	$ per MWh
Mountain Dell Dam	Hydroelectric	Net Metered	$1.551	$0.019	$0.355	$0.064	($0.228)	$92.00

7.4 Terminal and Park Reservoirs Solar PV Site

The Terminal and Park Reservoirs solar PV site is located directly west of I-215 at 3300 South in Salt Lake County.

The Terminal and Park Reservoirs site consists of four buried reservoirs (Terminal South, Terminal North, Sam Park, and Sam Park West) with open roof space that could be made available for installation of ground-mounted solar PV panels. The location provides a site that is unobstructed by

objects that would create shading impacts, security fencing, and direct access just south and west to a three-phase electrical distribution system.

A solar PV facility at the Terminal and Park Reservoirs site would likely utilize fixed tilt 275-W PV modules with an installed capacity of 3.5-MW AC and an average annual generation of 4,490,000 kWh.

A 3.5-MW solar PV installation was evaluated for Terminal and Park Reservoirs. The upfront capital costs of the system were estimated to be $11.3 million, and the annual non-fuel operating expense estimated at $13,000 per year. There is virtually no on-site load at this facility compared to the technical potential of the site, so net metering is not a practical option for this site. There are four options available for distributing the excess generation from a solar facility at the Terminal and Park Reservoirs, three of which are immediately available: Tariff Schedules 32, 37, and 38.

Assuming the value of the PV generation at the site would be based on the Schedule 37, NPV of the power generated by the solar array is estimated to exceed the value of electricity supplied by RMP by $10.2 million over the 30-year life of the project. Even when a price of carbon of $50/MTCO$_2$e is assumed in analysis the project still has an NPV of $7.2 million more than service provided by RMP.

Because Schedule 32 had not been finalized by the Public Service Commission at the time of the economic analysis, the economic viability of this tariff option was not evaluated. Although solar facilities are technically eligible for Schedule 32, this rate schedule may not be advantageous for solar projects due to the method by which the demand is calculated. However, this analysis did estimate NPV of the cost of utility service if an alternative net metering tariff were available to DPU and the electricity generated from the PRV Station B11-R13 could be credited to offset DPU loads at other locations. For purposes of this analysis it was assumed the applicable tariff is Schedule 6A.

The only circumstance where the Terminal and Park Reservoirs site would provide lower cost electricity service compared to RMP is by assuming an alternative net metering tariff is available to DPU at the equivalent of the average retail rate for Schedule 6A (i.e., 11.2772 cents per kWh), and including a $50/MTCO$_2$e in the cash flow analysis. Under this scenario, NPV of utility service of this project is $559,000 less than service provided by RMP.

This analysis did not include an assessment of leases or PPAs. Either of these financing structures would allow DPU to take advantage of a 30 percent federal tax incentive through a third-party ownership. Furthermore, the cost of solar has fallen significantly since this report was commissioned. If DPU were to utilize a lease or a PPA, take advantage of the falling cost of solar, and/or apply to receive an incentive through the Utah Solar Incentive Program, this project might offer a better NPV than the existing cost of utility service.

Table 7-5. Terminal and Park Reservoirs NPV of the Cost of Utility Service

Project Site	Type of Power Technology	Use of Generation	Overnight Capital	Non-Fuel Operating Expense	Cost of Utility Service Present Value $Millions			Levelized Cost
			2014$ Millions	2014$ Millions	$0 per MTCO2e	$25 per MTCO2e	$50 per MTCO2e	$ per MWh
Terminal Park Reservoir	Solar PV	Schedule 37	$11.292	$0.150	$10.155	$8.699	$7.242	$139.50
	Solar PV	Net Metered			$2.354	$0.898	($0.559)	$139.50

7.5 PRV Station B11-R13 Hydroelectric Site

The PRV station B11-R13 hydroelectric site is located at the intersection of 1000 East 500 South in Salt Lake City. An existing vault containing two PRV valves is located on-site. A hydroelectric facility would likely be located at the same location or adjacent to the existing PRV vault.

A 190-kW hydroelectric turbine is proposed to generate electricity using pressure head at an existing PRV in a vault structure. A hydroelectric facility at the B11-R13 PRV would likely utilize a reverse pump-type turbine with an installed capacity of 190-kW and an average annual generation of 773,000 kWh.

The upfront capital costs of this renewable energy system are estimated to be $1 million and the annual non-fuel operating expense at the site is estimated to be $13,000 per year. Interior lighting for the vault is the extent of the on-site load, so net metering is not a practical option for this site. There are only two options available for distributing the generation from the B11-R13 PRV vault, Tariff Schedules 32 and 37.

Assuming the value of the electricity produced at the site would be based on the Schedule 37, NPV of the power generated by this micro-hydroelectric project is estimated to exceed the value of electricity supplied by RMP by $585,000 over the 50-year life of the project. However, when a price of $50/MTCO$_2$e is incorporated into the cash flow analysis, the project is economic. Under this scenario, NPV of the cost of utility service is $68,000 less than service provided by RMP.

Because Schedule 32 had not been finalized by the Public Service Commission at the time of the economic analysis, the economic viability of this tariff option was not evaluated. However, this analysis did estimate the NPV of the cost of utility service if an alternative net metering tariff were available to DPU. Alternative net metering tariffs could allow parties who own renewable generation facilities at one location to receive credit for that generation at another. Under such a tariff, the facility does not have to be adjacent to the renewable energy project. In this scenario, electricity generated from the B11-R13 PRV station could be credited to offset DPU loads at other locations. For purposes of this analysis it was assumed the value of electricity that would be offset by the PRV station micro-hydroelectric project would be equivalent to the published Schedule 6A rate.

Table 7-6. PRV Station B11-R13 Hydroelectric NPV of the Cost of Utility Service

Project Site	Type of Power Technology	Use of Generation	Overnight Capital	Non-Fuel Operating Expense	Cost of Utility Service Present Value $Millions			Levelized Cost
			2014$ Millions	2014$ Millions	$0 per MTCO2e	$25 per MTCO2e	$50 per MTCO2e	$ per MWh
PRV Station B11-R13	Micro-Hydro	Schedule 37	$0.999	$0.015	$0.585	$0.258	($0.068)	$55.50
		Virtual Net Metering			($0.188)	($0.515)	($0.841)	$55.50

Assuming an alternative net metering tariff is available improves the economic viability of the B11-R13 PRV project significantly. NPV of electricity service from the project is $188,000 less than electricity service provided by RMP over the 50-year project life. When a cost of CO_2e is incorporated into the cash flow analysis, the economics of the project are strengthened even further. At $25/MTCO$_2$e, NPV is $515,000 less than the business-as-usual scenario; and when the price of carbon is assumed to be $50/MTCO$_2$e, NPV of the project improves to $841,000.

7.6 West Temple Wastewater Heat Recovery Site

The wastewater heat recovery site, located adjacent to DPU's main office in Salt Lake City, would utilize a heat exchanger to extract heat from wastewater flowing in the sewer trunkline along West Temple. A heat exchanger and pump would be utilized to provide space heating to DPU's main office.

The economic analysis at this site was performed assuming the addition of a 156-kW heat exchanger with a 60-kW heat pump tied into the 36-inch sewer trunkline adjacent to the main DPU office building, and that the addition of a new, low-heat delivery system would be integrated with the existing buildings. The upfront capital costs of the wastewater heat recovery system and low temperature heat delivery system was estimated to be $695,000, and the annual non-fuel operating expenses were assumed to be zero. The system is estimated to conserve 1,862 MMBtu of natural gas annually. However, the addition of a heat pump would increase electricity use at DPU's main office by 123.6 MWh each year. Based on these assumptions, NPV of the cost of utility service of the wastewater heat recovery system is estimated to exceed the value of natural gas service provided by Questar by $602,000 over the 30 year-life of the project. At a price of $50/MTCO$_2$e, the project only performs marginally better due to the fact the annual average avoided carbon dioxide emissions from the project is only 41 metric tons per year.

Table 7-7. West Temple Wastewater Heat Recovery NPV of the Cost of Utility Service

Project Site	Type of Power Technology	Use of Generation	Overnight Capital	Non-Fuel Operating Expense	Cost of Utility Service Present Value $Millions			Levelized Cost
			2014$ Millions	2014$ Millions	$0 per MTCO2e	$25 per MTCO2e	$50 per MTCO2e	$ per MWh
DPU Office	Heat Recovery	N/A	$0.695	$0.000	$0.602	$0.584	$0.566	N/A

8.0 POTENTIAL PROJECT FINANCING MECHANISMS

This section of the plan is intended to assist DPU with identifying financing mechanisms to support the deployment of renewable energy technologies on DPU-owned and operated property. While the Consultant Team recognizes it is DPU's preference to internally fund renewable energy projects using revenue from its utility operations, there are opportunities to leverage DPU's available funds with other funding sources to accelerate the deployment of City-owned renewable energy projects and the benefits associated with renewable energy deployment. This includes creating new local-based economic opportunities, increasing diversity of DPU electricity supply, mitigating risk of higher energy prices in the future, and reducing CO_2 emissions.

8.1 Apply for the Utah Solar Incentive Program (USIP)

This program is available to any customer whose bills are subject to the Schedule 195 solar incentive program surcharge. In 2016, the program will provide a $0.85 per-watt incentive for the upfront cost of installing a solar project less than 25-kW in size, or a $0.65 per-watt incentive for a solar project greater than 25-kW in size (with a maximum value of $650,000). The incentive is awarded through a lottery. In 2016, incentives will be available for 4,500-kW of capacity for projects less than 25-kW in size, and 10,000-kW of capacity for projects greater than 25-kW in size. In 2014, RMP awarded incentives to 100 percent of small commercial applicants and 37 percent of large commercial applicants. The USIP cannot be used in conjunction with any other RMP grant or incentive programs, including the Blue Sky Community Grants. For more information and application instructions, see Appendix D.

8.2 Apply for a Blue Sky Community Grant

Renewable energy installations, including hydroelectric projects, can apply to receive a Blue Sky Community Grant. RMP accepts applications for Blue Sky Community grants on an annual basis. Blue Sky grants can only fund up to 60 percent of the total project costs. See Appendix D for more details.

8.3 Consider a PPA

Power Purchase Agreements (PPAs) are available to local governments in Utah for net-metered projects. PPAs are a commonly used financing mechanism for solar installations, offering solar electricity at no upfront cost. PPAs allow a third-party developer to build, own, and maintain a solar photovoltaic system at a DPU facility. DPU would agree to purchase electricity produced by the solar panels at a fixed price for a predetermined time period. This arrangement offers significant cost savings because the third party developer can take advantage of tax credits and pass on the savings to DPU. A PPA can include a "buy-out" option which would allow DPU to purchase the solar facility at a pro-rated price after the tax benefits have been utilized by the developer or investor. See Appendix D for more details.

8.4 Utilize Qualified Energy Conservation Bonds

Qualified Energy Conservation Bonds (QECBs) are a debt instrument that enables qualified states, territories, and local governments to issue tax credit bonds with very low effective interest rates in order to fund energy conservation or renewable energy projects. The State of Utah, Salt Lake City, and Salt Lake County all received a separate allocation for QECBs from the U.S. Department of the Treasury, and the majority of these allocations are still available. For more information about QECBs and how to apply, see Appendix D.

8.5 Finance with the U-Save Energy Fund Program

The U-Save Energy Fund finances energy-related cost reduction retrofits on existing equipment and installations for publically owned buildings by offering loans with low interest rates. A revolving loan mechanism allows borrowers to repay the loans using cost savings realized from the retrofits. Entities considering use of the U-Save Energy Fund are encouraged to evaluate renewable energy technologies, including rooftop solar water and space heating installations, solar photovoltaic, and small wind installations. A revolving loan mechanism allows borrowers to repay the loans using cost savings realized from the retrofits. For more information about the U-Save Energy Fund and instructions for applications, see Appendix D.

9.0 SUMMARY AND CONCLUSIONS

This Plan is a broad framework that identifies DPU's opportunities for renewable energy projects; evaluates their technical, economic, and practical feasibility; and provides strategies and recommendations for their implementation.

The purpose of the plan is to provide DPU with sufficient detail on the final selected 19 renewable energy projects that were evaluated in the Phase II detailed site evaluation to either allow for the subsequent development of renewable energy projects or to identify sites that show potential and are good candidates for additional assessment.

One of the objectives of this analysis was to identify potentially viable renewable energy projects that could increase the diversity of DPU's electricity supply and contribute to growing Salt Lake City's renewable energy portfolio and reducing its GHG footprint. It is clear from this assessment that DPU-managed infrastructure and property can support a diverse portfolio of renewable energy technologies and projects. Among the technologies evaluated at the 19 Phase II selected sites were biogas-fired cogeneration, distributed roof-mounted solar PV, utility-scale roof- and ground-mounted solar PV systems, conventional hydroelectric generation, wastewater heat recovery, and micro-hydroelectric projects. When combined, these sites demonstrate the technical potential to support the installation of renewable energy capacity that would generate 13,690 megawatt-hours (MWh) of electricity, enough to offset approximately 44 percent of the electricity currently purchased from Rocky Mountain Power and Murray City. The renewable energy potential is even greater if all 41 sites that were evaluated in Phase I are accounted for. Including these additional sites raises the renewable energy generation potential to 18,779 MWh.

Of course these numbers only represent the technical potential. Economics and regulatory feasibility are also necessary considerations that need to be accounted for when a decision is made to implement a project. From the outset it was understood that this study would form the foundation and provide guidance for more detailed future evaluations of project sites that could include analysis using more detailed engineering, site, and economic assessments. The scope of work and budget for this study did not allow for a regulatory assessment of rate schedules and economic analysis to be completed for each of the 19 candidate project sites that showed high technical potential. Accordingly, the DPU Steering Committee and Consultant Team selected six representative sites for further analysis that would enable DPU to benchmark the regulatory and economic performance of the remaining 13 sites and technologies for future consideration.

9.1 Economic Analysis

Of the six renewable energy project sites selected for the more detailed regulatory and economic assessment, five sites involved projects that would generate electricity; the Terminal and Park Reservoirs, 15th East Reservoir, Mountain Dell Dam, PRV Station B11-R13, and the Salt Lake City

Water Reclamation Facility biogas cogeneration project. One site, the DPU Campus wastewater heat recovery project, would offset heating load, decreasing the purchases of natural gas.

The combined estimated overnight capital investment required to develop the four solar PV projects and hydroelectric projects is $14.8 million. Based on the generation capacities assumed in this analysis these four projects would be able to generate 6,287 MWh of electricity and avoid 4,735 $MTCO_2e$ of GHG emissions.

The economic analysis of biogas cogeneration at the SLCWRF considered increasing the generation of underutilized capacity of the two engines and replacement with four different technology options utilizing biogas produced at the treatment plant. If the SLCWRF retained the use of the two 700-kW reciprocating engines and operated them to utilize all the available biogas produced at the treat plant, it could avoid any additional capital investment and generate 2,553 MWh more electricity while reducing the GHG emissions associated with SLCWRF operations by 1,558 $MTCO_2e$. An overnight capital investment of between $6.7 and $12.1 million would be required to replace the two existing 700-kW engines with either a new 1400-kW reciprocating engine, an 844-kW micro-turbine or a 1330-kW fuel cell.

For an estimated capital investment of $695,000, DPU could also install wastewater heat recovery technology to supplement heating load at DPU's main office complex. This option would reduce natural gas consumed by the existing boiler by 1,862 MMBTU but increase the electricity consumption by 123.6 MWh, resulting in a net reduction of GHG emissions of 41 $MTCO_2e$.
For purpose of this study, the economic viability of each project is determined by quantifying the NPV of the cost of utility service, as measured by cash flow throughout the life of the project, and then comparing the costs to a business-as-usual case where DPU continues to receive utility service from either RMP or Questar. If NPV is negative, the costs of electricity or natural gas produced by the renewable energy project is less than utility service over the life of the project. Therefore, the project is economical.

While all six projects were technically feasible and provided good locations for the development of renewable energy, only one project proved to be economically viable under the current regulatory, utility pricing, and economic assumptions adopted for this analysis. Using the NPV of the cost of utility service as the metric for demonstrating financial viability, only the SLCWRF biogas cogeneration was able to meet this cost effectiveness threshold. An operational change would allow DPU to operate both 700-kW engines to utilize all the biogas produced by the plant with no additional capital investment. This technology option proved cost effective whether both engines were operated using biogas or supplemented with natural gas to maximize generation capacity.

Table 9-1. Economic Ranking of Renewable Energy Projects
(Net Present Value of the Cost of Utility Service)

Project Site	Type of Power Technology	Use of Generation	Overnight Capital	Non-Fuel Operating Expense	Cost of Utility Service Present Value $Millions			Levelized Cost
			2014$ Millions	2014$ Millions	$0 per MTCO2e	$25 per MTCO2e	$50 per MTCO2e	$ per MWh
SLCWRF	Existing Recip (Biogas)	Schedule 31	$0.000	$76.579	($1.458)	($1.996)	($2.533)	$26.50
SLCWRF	Existing Recip (Biogas/NG)	Schedule 31	$0.000	$109.272	($0.273)	(0.697)	($1.120)	$35.50
PRV Station B11-R13	Micro-Hydro	Virtual Net Metering	$0.999	$0.015	($0.188)	($0.515)	($0.841)	$55.50
Mountain Dell Dam	Hydroelectric	Net Metered	$1.551	$0.019	$0.355	$0.064	($0.228)	$92.00
15th East Reservoir	Solar PV	Net Metered	$0.920	$0.013	$0.426	$0.314	$0.202	$153.50
PRV Station B11-R13	Micro-Hydro	Schedule 37	$0.999	$0.015	$0.585	$0.258	($0.068)	$55.50
DPU Office	Heat Recovery	N/A	$0.695	$0.000	$0.602	$0.584	$0.566	N/A
Terminal Park Reservoir	Solar PV	Virtual Net Metering	$11.292	$0.150	$2.354	$0.898	($0.559)	$139.50
Terminal Park Reservoir	Solar PV	Schedule 37	$11.292	$0.150	$10.155	$8.699	$7.242	$139.50

The economic analysis also included a sensitivity analysis that incorporated a cost of carbon into the cash flow analysis to account for potential future GHG regulations and the additional costs it would add to electricity generated from fossil fuels. The assumed cost of carbon for this sensitivity analysis was $25/MTCO$_2$e and $50/MTCO$_2$e. The economic viability of the six projects improved when a price for carbon dioxide was incorporated into the cash flow analysis to account for future fuel price and regulatory risk of GHG regulations. The point to be made about the results of this price sensitivity scenario is that DPU can view the development, generation, and use of electricity from on-site renewable energy projects as a hedge against fuel and energy price increases due to future GHG regulations.

A second sensitivity analysis assumed the generation from the PRV station B11-R13 and Terminal and Park Reservoirs could be used to offset electricity consumed at other DPU facilities through an alternative net metering arrangement (which is not currently available in Utah). Under this assumption, NPV of the PRV Station B11-R13 project exceeds the value of utility service provided by RMP under all cost-of-carbon regulation scenarios. The Terminal and Park Reservoirs solar PV project was still uneconomical under the $0 and $25/MTCO$_2$e cost assumptions but became economically viable when a price of $50/MTCO$_2$e was incorporated into the cash flow analysis. Economics of all the projects evaluated could be improved through DPU adopting some form of third party alternative financing such as a lease or a PPA.

9.2 GHG Emissions

Considering the six renewable energy projects from the standpoint of their contribution to reducing DPU's GHG emissions footprint, the Terminal and Park Reservoirs project has the biggest impact by avoiding 3,381 $MTCO_2e$. This represents approximately 13 percent of the GHG emissions associated with DPU's consumption of purchased electricity and natural gas. The two SLCWRF cogeneration options, where biogas and biogas plus supplemental natural gas are burned to enable the existing engines to run a higher capacity factors, contribute the next largest GHG emissions reductions, avoiding 1,553 and 1,233 $MTCO_2e$.

If DPU developed all six renewable energy projects, it is estimated it could reduce its GHG emissions footprint by 6,228 $MTCO_2e$, or 25 percent.

Table 9-2. Estimated Avoided GHG Emissions by Project

Project Site	Type of Power Technology	Use of Generation	Average Annual Generation	Annual GHG Emissions
			MWh	MTCO2e
SLCWRF	Existing Recip (Biogas)	Schedule 31	2,553	1,553
SLCWRF	Existing Recip (Biogas/NG)	Schedule 31	3,642	1,233
PRV Station B11-R13	Micro-Hydro	Virtual Net Metering	773	582
Mountain Dell Dam	Hydroelectric	Net Metered	690	520
15th East Reservoir	Solar PV	Net Metered	335	252
PRV Station B11-R13	Micro-Hydro	Schedule 37	773	582
DPU Office	Heat Recovery	None	(124)	41
Terminal Park Reservoir	Solar PV	Virtual Net Metering	4,489	3,381
Terminal Park Reservoir	Solar PV	Schedule 37	4,489	3,381

9.3 Rate Schedule Assessment

The regulatory rate schedule assessment evaluated tariff options at each of the renewable energy project sites to determine what tariff rate options were available and would maximize the economic benefits of the proposed renewable energy projects.

The first question addressed was whether the site was on the most appropriate tariff given existing consumption of electricity. Two sites, Mountain Dell and the 15th East Reservoir, are currently receiving power on Schedule 6A, a "time-of-use" tariff, that charges higher rates for electricity consumed during "on-peak" hours and charges significantly lower rates during off-peak hours. In the absence of a renewable energy project at either site, Schedule 6A may not be the appropriate rate schedule or offer the best pricing.

The next question considered at each potential renewable energy site was whether the project would produce electricity that would contribute to meeting load or would generate excess at the site. If excess generation is likely from the new renewable project then options for selling electricity back to RMP were evaluated and considered in the context of maximizing the value DPU would receive for the additional generation.

Based on price, the most advantageous rate RMP currently offers for renewable energy projects is Schedule 135—Net Metering. This tariff is offered to customers with on-site renewable facilities to be connected to the grid and receive credit for excess electricity produced but not consumed at the site. Thus the customer is billed for their "net usage" over the course of a month.

Additionally, for the cogeneration development at the SCLWRF, or the renewable energy projects at the Terminal and Park Reservoirs, 15th East Reservoir, or the B11-R13 PRV station, excess sales to the grid are currently governed by either Schedule 37 (less than 1-MW for cogeneration or less than 3-MW for other renewable projects), or Schedule 38 (greater than 1-MW for cogeneration or greater than 3-MW for other renewable projects). In either case, selling electricity to the grid serves as an important offset to the capital investment incurred with the renewable generation development.

Other rate considerations include the new Schedule 32, which would allow DPU to source a large portion of its electrical service from renewable resources obtained from sources other than RMP. This rate will soon be finalized by the Public Service Commission, and it will offer an alternative option for DPU. The rate has a 2-MW threshold, so aggregation of generation from smaller facilities will be critical for all projects except the Terminal and Park Reservoirs. DPU could aggregate a portfolio of renewable energy sites located throughout Salt Lake City which collectively meet the 2-MW threshold.

9.4 Financing

There are opportunities to leverage DPU's available funds with other funding sources to lower the upfront capital costs and accelerate the deployment of City-owned renewable energy projects. All of the funding sources and financing mechanisms identified by the Consultant Team are viable options for lowering the upfront capital investment required by DPU. Moreover, from the perspective of DPU, lowering the capital investment will improve the economic viability of the projects that receive supplemental funding.

10.0 RECOMMENDATIONS

10.1 Renewable Energy Projects

Based on the analysis conducted by the project team, the following recommendations are offered for action in the near-term:

1. Salt Lake City Wastewater Reclamation Facility

The SLCWRF's existing cogeneration units offer the best and most cost-effective near-term opportunity for DPU to increase the generation of electricity from renewable energy sources and significantly reduce its carbon footprint. DPU should:

- Implement changes in the operations of the existing cogeneration engines at the site. There is sufficient biogas produced at the site to increase utilization of the existing engines by 50percent without running up against limitations placed on the amount of electricity the SLCWRF can produce under RMP's Tariff Schedule 31.
- More fully utilize existing digester gas production capacity by incorporating a fats, oils and grease (FOG) collection program and add this waste stream to the digesters at the SLCWRF. This would increase the production of biogas and enable the cogeneration engines to operate at near capacity.
- In the absence of a FOG program, SLCWRF should supplement the biogas burned by the cogeneration engines with natural gas. While the GHG emissions reduction benefits are decreased, burning natural gas in combination with biogas is still economic from a cost of utility service perspective.
- Evaluate the regulatory opportunity and economics of generating excess power for sale to RMP under Schedules 37 or 38, or to deliver excess generated electricity to one of DPU's other electricity loads under Schedule 32.

2. 15th East Reservoir Site

The 15th East Reservoir site is an excellent candidate for a solar PV installation from a location, resource, and technology standpoint. A 274-kW solar installation was evaluated at the 15th East Reservoir site and proved to be uneconomical from a NPV cost of utility service perspective. However, the 274-kW system would generate almost five times more electricity than is necessary to meet the needs of the reservoir's operations. A net-metered, 25-kW installation sized to offset on-site electricity usage would significantly reduce the upfront capital costs and improve the economic viability of the project. This site is a strong candidate for a solar PV project and additional analysis should be conducted by DPU to further evaluate design alternatives, regulatory strategies, and alternative financing options that could improve its economic viability. DPU should evaluate:

- Whether the electric service at the 15th East Reservoir site could be aggregated with electric meters at the adjacent Rice Eccles Stadium to take full advantage of net metering and the 274-kW solar generation capacity the site would support.
- The economic advantages of a third party project financing mechanism such as a lease or a PPA. This would allow DPU to take advantage of a federal tax incentive through a third-party ownership structure, which could reduce the cost by 30 percent and improve the economics of the project.
- Evaluate the economics of a solar PV system that is designed to optimize the size of the system based on on-site load. At a minimum, it will reduce the upfront capital costs of the project and significantly improve the NPV cost of utility service over the life of the project.

3. Mountain Dell Dam Hydroelectric Project

The Mountain Dell Reservoir hydroelectric project is considered an attractive site for development because of the ease of interconnection to existing load, and the potential for the hydroelectric power system to be net metered and offset 75 percent of the power currently purchased from RMP at $0.1128 per kWh. The project proved economical on a NPV basis when price of \$50/$MTCO_2e$ is assumed in the cash flow analysis. There is an opportunity to significantly improve the financial viability of this project and reduce DPU's upfront capital costs through a lease or a PPA. DPU should investigate this type of arrangement before the federal tax incentives expire at the end of 2016.

4. Pressure Release Valve Station B11-R13 Micro-Hydroelectric Project

Like the Mountain Dell hydroelectric project, the PRV B11-R13 micro-hydro project was economically viable when a price of \$ 50/$MTCO_2e$ was used in the cash flow analysis to account for the potential costs of future GHG regulations. Because of the number of PRV stations operated by DPU, the successful demonstration of the technical viability of this technology at the PRV B11-R13 station site creates the opportunity to develop many more micro-hydroelectric sites in the DPU water system. From the standpoint of DPU, the economics of this project and others could be improved further by leveraging the federal renewable energy tax incentives to attract a third party development partner who could take advantage of the tax credits, and financing that would offset a portion of the upfront capital costs of the project.

5. Terminal and Park Reservoir Solar PV Project

The Terminal and Park Reservoir site could support a 3.5-MW solar PV installation capable of generating an annual average of 4,490,000 kWh. The only circumstance where the Terminal Park Reservoirs site would provide lower cost electricity service compared to RMP is by assuming an alternative net metering tariff is available to DPU at the equivalent of the average retail rate for Schedule 6A (i.e., 11.28 cents per kWh), and including a \$50/$MTCO_2e$ in the cash flow analysis. Like the other renewable energy projects that require a major capital investment, there is an opportunity to significantly improve the financial viability of this project and reduce DPU's up-front capital costs through a lease or a PPA with a third party who can take advantage of the federal tax incentives.

This is the single largest renewable energy project opportunity among the 151 project sites evaluated and it provides the greatest opportunity to offset RMP electricity purchases and reduce DPU's carbon footprint. DPU should investigate the opportunity to enter into third party alternative financing arrangement before the federal tax incentives expire at the end of 2016 as a strategy to improve the economics of the project.

6. Solar Photovoltaic (PV) Rooftop Projects

Solar PV rooftop projects scored very high relative to all projects in the detailed site evaluations but were not selected for regulatory and economic analysis in Phase II. PV rooftop systems offer the opportunity to offset each kWh generated at the full costs of power delivered to DPU facilities by local electricity providers, and are scalable to the available space on a building. DPU should conduct a more complete evaluation of all available roof space and the economic viability of these systems. Moreover, because of the renewable energy opportunity offered by solar PV, Salt Lake City government should consider adopting construction standards for new and renovated buildings that require consideration of solar PV and integrate solar-ready building techniques into future construction or renovation. To improve the economics of rooftop solar, DPU should apply for the Utah Solar Incentive Program. This program awards an incentive for solar projects through a lottery and will expire after January 2017. DPU should also consider using a PPA to leverage the 30 percent federal tax credit that expires in 2016.

7. DPU Main Office Wastewater Heat Recovery Project

A wastewater heat recovery project adjacent to DPU's main office in Salt Lake City would utilize a heat exchanger/heat pump to extract heat from wastewater flowing in the sewer trunkline along West Temple, and provide supplemental space heating to DPU's main office. The heat exchanger/heat pump system for this project can also be configured to provide cooling during the summer months. The screening level data and design parameters used for this analysis did not provide sufficient detail to enable evaluation of the cooling capabilities of this technology. If DPU is interested in a more detailed investigation of this technology, it is recommended that the City evaluate the cooling capability of reconfiguring wastewater heat recovery technology to be tied to the existing HVAC system.

10.2 Regulatory

1. Salt Lake City Wastewater Reclamation Facility

SLCWRF is currently constrained from operating its two 700 kW-reciprocating engine cogeneration system at full capacity due to prohibitions against generation exceeding load at the site. In order to take full advantage of the economic and environmental benefits of available biogas and underutilized cogeneration capacity, DPU should evaluate the regulatory implications and economics of generating excess electricity under the various rate schedules associated with its on-site generation capacity, i.e., Schedules 31 and 9. Neither Schedule 31 nor Schedule 9 allows net metering or selling excess power back to RMP. However, as a facility taking service under Schedule 31, SLCWRF might

be able to sell excess electricity back to the utility at wholesale “avoided costs” rates using either Schedule 37 (if the capacity sold is less than 1-MW) or Schedule 38 (if greater than 1-MW).

2. Mountain Dell Hydroelectric Project

The Parley’s Canyon Water Treatment Plant is currently receiving electricity service through Schedule 6A. Based on the load shape of electricity use at this site, Schedule 6A might not be best tariff. DPU should assess whether the water treatment plant is eligible for a different tariff. If the hydroelectric project is developed at Mountain Dell, this site is a good candidate for net metering on Schedule 135.

3. Pressure Release Valve Station B11-R13 Micro-Hydroelectric Project

A micro-hydro project installed at the PRV station B11-R13 will generate more electricity than there is load at the site. DPU should certify this PRV project as a QF and make it eligible to sell power back to RMP under Schedule 37.

4. Electric Service Schedule 32

End use customers utilizing Schedule 32 must contract to take more than 2-MW of electricity delivery; however, the law permits multiple renewable energy facilities to deliver electricity to a single contract customer. Given the multiple renewable opportunities identified by this study, DPU should evaluate whether or not it would be feasible and economic to build a 2-MW portfolio of projects to serve DPU loads under this tariff.

5. Alternative Net Metering

Alternative net metering policies improved the economics of the Terminal and Park Reservoirs, and PRV B11-R13 projects. As a leader and advocate for clean energy and the environment, Salt Lake City should consider advocating for regulatory policies that allow the City to use credits generated at one facility to offset electrical bills at another facility.

10.3 Alternative Financing

1. Utah Solar Incentive Program

Due to the number of Solar PV development opportunities, DPU should apply for the Utah Solar Incentive Program for both small solar PV (less than 25-kW) and large solar projects up to 1-MW to fund projects. The current program will sunset in 2017.

2. Lease and Power Purchase Agreements

There are alternative financing opportunities to leverage DPU’s available funds with other funding sources to lower the upfront capital costs and accelerate the deployment of City-owned renewable energy projects. DPU should consider lease structures or PPAs as a financing mechanism that reduces cost through tax incentives. The current 30 percent federal tax credit is set to revert to 10 percent at the end of 2016.

Appendix A

Phase I Evaluation Matrix

Tank Name	Capacity (kW)	Annual AC Energy (kWh)	On-Site or Adjacent Loads	Generation Points			Site Charateristics Points													Environmental Points					Total Poiint	Comments
				Initial Points	Weighting Factor	Weighted Points	Potential to Offset Existing DPU Load	Initial Points	Weighting Factor	Potential to Interconnect	Initial Points	Weighting Factor	Distance to Distribution Infrastructure	Initial Points	Weighting Factor	% DPU Load Displaced	Initial Points	Weighting Factor	Weighted Points	Impact	Acceptance	Initial Points	Weighting Factor	Weighted Points		
Water Tank/Reservoir - Roof Mount																										
Terminal Reservoirs/Park Reservoir	1,562	2,280,520	Wells 3580 E #4 & #5	5	5	25	Yes	3	2	Yes	5	2	<0.2 mi	4	4	100	5	2	42	Negligible	100%	5	5	25	92	
Baskin Reservoir	395	576,700	Bonneville PS	4	5	20	Yes	3	2	Yes	5	2	<0.2 mi	4	4	34	2	2	36	Negligible	100%	5	5	25	81	
15th East Reservoir	290	423,400	500 S Well & University PS	3	5	15	Yes	5	2	Yes	5	2	<0.1 mi	5	4	No data	1	2	42	Negligible	100%	5	5	25	82	
Military Reservoir	256	373,760	Military PS	3	5	15	Yes	5	2	Yes	5	2	<0.1 mi	5	4	15	1	2	42	Major	<50%	0	5	0	57	Reservoir is used as a park
Victory Road Reservior	248	362,080		3	5	15	No	0	2	Yes	5	2	<0.3 mi	3	4	0		2	22	Negligible	100%	5	5	25	62	
Wilson Reservoir	241	351,860	Arlington Hills PS	3	5	15	Yes	5	2	Yes	5	2	<0.1 mi	5	4	25	2	2	44	Negligible	100%	5	5	25	84	
Marcus Reservoir	190	277,400		3	5	15	No	0	2	Yes	5	2	<0.1 mi	5	4	0		2	30	Negligible	100%	5	5	25	70	
Morris Reservoir	176	256,960	North Bench PS	3	5	15	Yes	5	2	Yes	5	2	<0.1 mi	5	4	86	5	2	50	Negligible	100%	5	5	25	90	
McEntire Reservoir	142	207,320		2	5	10	No	0	2	Yes	5	2	<0.1 mi	5	4	0		2	30	Major	<50%	0	5	0	40	Reservoir is used as a park
13th East Reservoir	114	166,440		2	5	10	No	0	2	Yes	5	2	<0.1 mi	5	4	0		2	30	Major	<50%	0	5	0	40	Reservoir is used as a park
Ensign Downs Lower Tank	105	153,300	Ensign Downs PS	2	5	10	Yes	5	2	Likely	3	2	<0.3 mi	3	4	No data	1	2	30	Negligible	100%	5	5	25	65	
Tanner Reservoir	67	97,820	Dyers Inn Well	1	5	5	Yes	5	2	Yes	5	2	<0.1 mi	5	4	4	1	2	42	Negligible	100%	5	5	25	72	Low generation but DPU load on-site
Granite Oaks Tank/Telford Reservoir	54	78,840	Granite Oaks PS	1	5	5	Yes	5	2	Yes	5	2	<0.1 mi	5	4	No data	1	2	42	Negligible	100%	5	5	25	72	Low generation but DPU load on-site
Tavaci Tank	47	68,620	Tavici PS	1	5	5	Yes	2	2	Maybe	1	2	<0.5 mi	1	4	No data	1	2	12	Negligible	100%	5	5	25	42	Low generation but DPU load on-site
Mt Opympus Tanks	45	65,700	Mount Olympus PS	1	5	5	Yes	5	2	Yes	5	2	<0.1 mi	5	4	9	1	2	42	Negligible	100%	5	5	25	72	Low generation but DPU load on-site
East Bench Tanks	38	55,480	Carrigan Cove PS	1	5	5	Yes	5	2	Yes	5	2	<0.1 mi	5	4	69	4	2	48	Negligible	100%	5	5	25	78	Low generation but DPU load on-site
Eastwood Tanks	14	20,440	Eastwood PS	1	5	5	Yes	5	2	Yes	5	2	<0.1 mi	5	4	4	1	2	42	Negligible	100%	5	5	25	72	Low generation but DPU load on-site
Millcreek Tank	2	2,920	Lower Boundary PS	1	5	5	Yes	5	2	Yes	5	2	<0.1 mi	5	4	1	1	2	42	Negligible	100%	5	5	25	72	Low generation but DPU load on-site
Buildings - Roof Mount																										
Boeing	733	1,070,180	Building Load	5	5	25	Yes	5	2	Yes	5	2	<0.1 mi	5	4	No data	1	2	42	Negligible	100%	5	5	25	92	
XPEDX	456	665,760	Building Load	4	5	20	Yes	5	2	Yes	5	2	<0.1 mi	5	4	No data	1	2	42	Negligible	100%	5	5	25	87	
Highland High School	333	486,180	Building Load	3	5	15	Yes	5	2	Yes	5	2	<0.1 mi	5	4	No data	1	2	42	Negligible	100%	5	5	25	82	
Roberts Restaurant and Adjacent Building	267	389,820	Building Load	3	5	15	Yes	5	2	Yes	5	2	<0.1 mi	5	4	No data	1	2	42	Negligible	100%	5	5	25	82	
410 N. Wright Brothers Drive	228	332,880	Building Load	3	5	15	Yes	5	2	Yes	5	2	<0.1 mi	5	4	No data	1	2	42	Negligible	100%	5	5	25	82	
Salt Lake City Sports Complex	187	273,020	Building Load	3	5	15	Yes	5	2	Yes	5	2	<0.1 mi	5	4	No data	1	2	42	Negligible	100%	5	5	25	82	
The Leonardo	91	132,860	Building Load	2	5	10	Yes	5	2	Yes	5	2	<0.1 mi	5	4	No data	1	2	42	Minor	90%	4	5	20	72	
Sorenson Multicultural and Unity Fitness Center	58	84,680	Building Load	1	5	5	Yes	5	2	Yes	5	2	<0.1 mi	5	4	No data	1	2	42	Negligible	100%	5	5	25	72	
SLCDPU Buildings	57	83,220	Building Load	1	5	5	Yes	5	2	Yes	5	2	<0.1 mi	5	4	7	1	2	42	Negligible	100%	5	5	25	72	
Open Parcel - Ground Mount																										
South Lift	299	436,540	South Sewer LS	3	5	15	Yes	5	2	Yes	5	2	<0.1 mi	5	4	100	5	2	50	Negligible	100%	5	5	25	90	
Smith & Loveless	85	124,100	Smith & Loveless and 4000 W Sewer LS	2	5	10	Yes	5	2	Maybe	1	2	<0.3 mi	5	4	No data	1	2	34	Moderate	100%	1	5	5	49	
Concord Lift	79	115,340	Concord Sewer LS	2	5	10	Yes	5	2	Yes	5	2	<0.1 mi	5	4	100	5	2	50	Negligible	100%	5	5	25	85	
6200 S. Well	63	91,980	6200 S Well & 6200 S Irrigation PS	1	5	5	Yes	5	2	Yes	5	2	<0.1 mi	5	4	5	1	2	42	Negligible	100%	5	5	25	72	
Greenfield Village	51	74,460	Greenfield Village Well	1	5	5	Yes	5	2	Yes	5	2	<0.1 mi	5	4	6	1	2	42	Negligible	100%	5	5	25	72	

Facility ID	Capacity (kW)	Annual Generation (kWh)	On-Site or Adjacent Loads	Generation Points			Site Charateristics Points													Environmental Points					Total Poiint	Comments
				Initial Points	Weighting Factor	Weighted Points	Potential to Offset Existing DPU Load	Initial Points	Weighting Factor	Potential to Interconnect	Initial Points	Weighting Factor	Distance to Distribution Infrastructure	Initial Points	Weighting Factor	% DPU Load Displaced	Initial Points	Weighting Factor	Weighted Points	Impact	Acceptance	Initial Points	Weighting Factor	Weighted Points		
PRV																										
D74-DV1	359	1,310,352		5	5	25	No	0	2	Maybe	1	2	<0.3 mi	3	4	0	0	2	14	Negligible	100%	5	5	25	64	
B35-R18	422	1,539,757		5	5	25	No	0	2	Yes	5	2	<0.1 mi	5	4	0	0	2	30	Negligible	100%	5	5	25	80	
B11-R13	292	1,064,622		5	5	25	No	0	2	Yes	5	2	<0.1 mi	5	4	0	0	2	30	Negligible	100%	5	5	25	80	
C41-R20	281	1,025,114		5	5	25	No	0	2	Yes	5	2	<0.1 mi	5	4	0	0	2	30	Negligible	100%	5	5	25	80	
B6-R73	266	970,091		4	5	20	No	0	2	Yes	5	2	<0.1 mi	5	4	0	0	2	30	Negligible	100%	5	5	25	75	
D69-R40	63	228,660		2	5	10	No	0	2	Yes	5	2	<0.1 mi	5	4	0	0	2	30	Negligible	100%	5	5	25	65	
A23-R5	59	216,797		2	5	10	No	0	2	Yes	4	2	<0.1 mi	5	4	0	0	2	28	Negligible	100%	5	5	25	63	
C1-R74	54	196,973		2	5	10	No	0	2	Yes	5	2	<0.1 mi	5	4	0	0	2	30	Negligible	100%	5	5	25	65	
F78-CR28	41	151,340		2	5	10	No	0	2	Maybe	1	2		1	4	0	0	2	6	Negligible	100%	5	5	25	41	
G35-CR53	36	131,639	Private Well	2	5	10	Yes	4	2	Yes	5	2	<0.1 mi	5	4	0	0	2	38	Negligible	100%	5	5	25	73	
G38-CR57	17	62,052	7800 S PS	1	5	5	Yes	4	2	Yes	5	2	<0.1 mi	5	4	7	1	2	40	Negligible	100%	5	5	25	70	Low generation but DPU load on-site
Surface Water																										
Mountain Dell Dam	410	2,370,536	Parley's WTP	5	5	25	Yes	5	2	Yes	5	2	<0.1 mi	5	4	100	5	2	50	Minor	100%	4.5	5	22.5	98	
Big Spill	15	65,520	On-site pump, lighting and gates	1	5	5	Yes	5	2	Likely	3	2	<0.4 mi	2	4	100	5	2	34	Minor	100%	4.5	5	22.5	62	Low generation but DPU load on-site

Appendix B

Technical Memorandum – Cogeneration Assessment
Carollo Engineers

SALT LAKE CITY
DEPARTMENT OF PUBLIC UTILITIES

TECHNICAL MEMORANDUM
COGENERATION ASSESSMENT

REVISED FINAL
November 2014

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SALT LAKE CITY
DEPARTMENT OF PUBLIC UTILITIES

TECHNICAL MEMORANDUM
COGENERATION ASSESSMENT

TECHNICAL MEMORANDUM

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1.0 INTRODUCTION

1.1 Background

The Salt Lake City Water Reclamation Facility (SLCWRF) treats up to 56 million gallons of wastewater a day and is owned and operated by the Salt Lake City Department of Public Utilities (SLCDPU). SLCWRF is located on the north end of the City at 2300 North, between Redwood Road on the West and the Oil Drain Canal on the East. SLCWRF was originally constructed in the early 1960s, and has undergone numerous upgrades and expansions since then.

Currently, a combined trickling filter and activated sludge process is used at SLCWRF to remove organic wastes and treat wastewater prior to its release back to the environment. Waste activated solids are co-settled with primary solids in the primary clarifiers, thickened through gravity thickeners, mixed with scum collected from process basins and stabilized in anaerobic digesters. After digestion, solids are dried in solar dying beds and hauled away for use as daily cover at the county landfill.

Digester gas, consisting of mostly methane, is collected and cleaned prior to combustion in engine generators for energy recovery and a boiler for digester heating needs. Energy recovered through the combustion of digester gas offsets the amount of power that must be purchased from the local energy utility. An excess digester gas above what can be used in the engine generators or boiler is destroyed by flare.

The purpose of this technical memorandum is to provide an assessment of cogeneration at SLCWRF as part of a larger citywide review of possible alternative energy projects.

1.2 Scope

The following alternatives were developed and evaluated based on life cycle costs and other evaluation parameters.

- Alternative 1 – Use Existing Cogeneration Engines – Run one engine with no natural gas supplementation.
- Alternative 2 – Use Existing Cogeneration Engines – Run two engines with no natural gas supplementation.
- Alternative 3 – Use Existing Cogeneration Engines – Run two engines with natural gas supplementation.

- Alternative 4 – Replace Existing Engines with a New Engine.
- Alternative 5 – Replace Existing Engines with New Microturbine.
- Alternative 6 – Replace Existing Engines with New Fuel Cell.

Each of these alternatives was evaluated based on digester gas production from two treatment process configurations, the current wastewater treatment process and a future biological nutrient removal (BNR) process.

2.0 BACKGROUND

2.1 Existing Cogeneration System

The existing system consists of two 700-kilowatt (kW) engine-generators. The cogeneration system provides electrical energy production and heat for the anaerobic digesters. SLCDPU's desire to minimize future energy costs, limit their greenhouse gas emissions, and better utilize the renewable energy available has prompted this cogeneration assessment. Allowing the existing system to become non-operative due to age, lack of available parts, or catastrophic failure will result in significantly higher energy costs, an increase in associated energy related greenhouse gas emissions, and will put the SLCDPU at greater economic risk due to potential volatile energy prices.

2.2 Current Gas Production

For 2013, SLCWRF's monthly gas production has ranged from 224,000 cf/d to 466,000 cf/d and averaged 358,000 cf/d (Table 1). The cogeneration system can produce a portion of the SLCWRF demands, but power must still be purchased.

The specific gas production rate can then be estimated by dividing the gas production by the measured volatile solids reduction (VSR). Generally, the specific gas production rate falls within a range of 12 to 18 cf/lb VS destroyed. Numbers outside of this range can indicate problems with either the gas meters or the sludge meters.

SLCWRF uses two different methods to measure their digester feed flow (a flow meter and a stroke counter) and two different methods to measure their digester feed total solids (TS) (density meter and lab samples) from both of their gravity thickeners. By combining these two different sludge flows and two different total solids concentrations, SLCWRF can compute four different digester feed TS loads as summarized below:

- Sludge flow meter combined with the lab sample for TS (FM-LS)
- Sludge flow meter combined with the density meter reading for TS (FM-DM)
- Stroke counter converted to flow combined with the lab sample for TS (SC-LS)

- Stroke counter converted to flow combined with the density meter reading for TS (SC-DM).

Table 1	**2013 Monthly Average Gas Production Cogeneration Assessment SLCDPU**
Month	**Monthly Average Gas Production, cf/d**
January	348,816
February	455,833
March	466,207
April	448,769
May	418,890
June	334,578
July	273,332
August	246,574
September	223,786
October	347,566
November	303,693
December	430,773
2013 Average	**358,235**

The digester feed volatile solids (VS) load was then calculated by multiplying each of the four different feed TS loads by the lab measured ratio of digester VS to TS resulting in the same four different digester feed VS load calculations.

It was assumed that the flow into the digester equaled the flow out of the digester and so the same two flow measurements, FM-LS and SC-LS, were used to calculate two digester VS loads.

The mass of volatile solids reduced (VSR) was then calculated four different ways by subtracting the two different digester VS loads from the four different digester feed VS loads:

Digester Feed VS (FM-LS) – Digester Sludge VS (FM-LS)

Digester Feed VS (FM-DM) – Digester Sludge VS (FM-LS)

Digester Feed VS (SC-LS) – Digester Sludge VS (SC-LS)

Digester Feed VS (SC-DM) – Digester Sludge VS (SC-LS)

Table 2 summarizes the monthly average VSR using the four different calculation methods. SLCWRF staff generally believes that the SC-LS data is the most accurate. As shown in Table 2, the yearly average VSR ranges from a low of 19,023 ppd (SC-LS) to a high of 24,488 ppd (FM-DM).

Table 2 2013 Monthly Average Volatile Solids Reduction Cogeneration Assessment SLCDPU

Month	VSR, ppd FM- LS	VSR, ppd FM-DM	VSR, ppd SC-LS	VSR, ppd SC-DM
January	23796	30384	22423	28205
February	27206	22490	18426	14694
March	27304	26749	23880	23761
April	26352	23073	24844	20913
May	28254	26860	23055	21986
June	28480	28805	19488	19624
July	21454	24381	17006	19209
August	16072	18704	13280	15462
September	15895	18241	11338	13329
October	22956	25878	17903	19994
November	22844	21231	15509	14623
December	21179	27245	19472	24891
2013 Average	23592	24488	19023	19649
Average Difference from SC-LS	+24%	+29%	--	+3%

The estimated specific gas production rate can be estimated by dividing the monthly gas production by the monthly VSR. These values are summarized in Table 3. The 2013 average specific gas production rate ranged from a low of 14.7 cf/lb for the FM-DM samples to a high of 19.1 cf/lb for the SC-LS samples. The VSR calculated using the flow meter yield specific gas production rates that are within the typical range, while the VSR calculated

using the stoke counter yield specific gas production rates that are slightly higher than the typical range. Since the SLCDPU has the most confidence in their SC-LS measurements, a specific gas production rate of 19.1 cf/lb was selected for planning purposes.

Table 3 2013 Monthly Average Specific Gas Production Rates
Cogeneration Assessment
SLCDPU

Month	cf/lb FM-LS	cf/lb FM-DM	cf/lb SC-LS	cf/lb SC-DM
January	14.7	11.5	15.6	12.4
February	16.8	20.3	24.7	31.0
March	17.1	17.4	19.5	19.6
April	17.0	19.5	18.1	21.5
May	14.8	15.6	18.2	19.1
June	11.7	11.6	17.2	17.0
July	12.7	11.2	16.1	14.2
August	15.3	13.2	18.6	15.9
September	14.1	12.3	19.7	16.8
October	15.1	13.4	19.4	17.4
November	13.3	14.3	19.6	20.8
December	20.3	15.8	22.1	17.3
2013 Average	15.3	14.7	19.1	18.6

2.3 Digester Gas Production Projections

The gas production was estimated for current flows and loads for three different operational schemes:

Co-thickening – No biological nutrient removal (BNR): Currently the plant co-thickens WAS in their primary clarifiers. The 2014 WRF Capacity Evaluation (Water Works Engineering) reports a fairly high primary clarifier TSS removal rate of 75% that they suggest could be due to the co-thickening operation. In this configuration, the digester feed VS is

around 28,000 ppd (as calculated using the SC-LS method) and they achieve approximately 66% VSR.

Separate thickening/mechanical dewatering – No BNR: In this configuration, the plant would be operated as it is currently configured except that the WAS would be separately thickened and the sludge drying beds would be replaced with mechanical dewatering. For this configuration, a lower primary clarifier TSS removal rate was assumed of 69%. Additionally, 95% capture was assumed for the WAS thickening and 90% capture was assumed for the mechanical dewatering. This configuration resulted in a higher VS load to the digesters and a slightly lower VSR due to a increase in the WAS to PS ratio in the digester feed.

Separate thickening – BNR: In this configuration, the plant would be operated for BNR with separate thickening of the WAS. This configuration resulted in a lower VS load than the separate thickening configuration with no BNR due to the longer solids retention time in the aeration basins, which resulted in a decrease in the VS load to the digester and a decrease in the degradability of the WAS VS. A low and a high gas production were calculated for this configuration because there was concern that conversion to BNR could reduce the specific gas production rate. The high gas production rate was estimated assuming a specific gas production rate of 19.1 cf/lb and a low gas production rate was estimated assuming a specific gas production rate of 15 cf/lb.

Table 4 summarizes the 2013 estimated gas production from each of these configurations. As shown in Table 4, separate thickening is estimated to increase the gas production by approximately 20% and operation in a BNR configuration (with separate thickening) is estimated to decrease the gas production by approximately 7%. Future gas production was estimated for each configuration by increasing the digester VS load by the projected increase in the equivalent population. 2040 gas production rates were estimated to range from 316,000 cf/d for BNR with the low specific gas production rate of 15 cf/d to a high of 538,000 cf/d with no BNR.

3.0 COGENERATION TECHNOLOGIES

Cogeneration equipment was sized to efficiently and economically utilize the digester gas generated at SLCWRF. Various types of cogeneration technologies can be employed to produce power from digester gas. The following section summarizes each of the technologies and presents the specific model and size of the technology considered for SLCWRF. Manufacturer information from equipment vendors is included in Appendix A for Reference.

Table 4	Estimated Gas Projection Cogeneration Assessment SLCDPU		
Year	**Current Configuration No BNR**	**Separate Thickening No BNR**	**Separate Thickening BNR**
2013	Dig Feed = 28,000 ppd VSR = 67% VSR = 19,000 ppd Gas = 358,000 cf/d	Dig Feed ~ 35,000 ppd VSR ~ 64% VSR ~ 22,000 ppd Gas ~ 425,000 cf/d	Dig Feed ~ 31,000 ppd VSR ~ 56% VSR ~ 17,000 ppd Gas ~ 332,000 cf/d (high) Gas ~ 261,000 cf/d (low)
2040	NA	Gas ~ 538,000 cf/d	Gas ~ 400,000 cf/d (high) Gas ~ 316,000 cf/d (low)

3.1 Conventional Reciprocating Engines

Reciprocating engines, developed more than 100 years ago, were the first of the fossil fuel-driven distributed generation (DG) technologies. Reciprocating engines can be found in applications ranging from fractional horsepower units to 60-megawatt (MW) base load electric power plants.

The engine cooling water and exhaust heat from reciprocating engines can be recovered in heat exchangers and used to provide heat for digester heating and/or facility hot water heating. Several lean burn reciprocating engine suppliers have new generation, high efficiency, and low emission units available for use with biogas including Cummins, Caterpillar (MWM), and GE/Jenbacher. These new engines have efficiencies of approximately 40 percent, which stays nearly constant throughout the typical operating range of 50-100 percent engine load. These engines typically convert approximately 40 percent (as a percentage of fuel input energy) to electrical output and 40-45 percent to heat using recovered energy from the engine cooling water and exhaust heat. The total overall efficiency of these reciprocating engines is approximately 80-85 percent. The engines are lean-burn, spark-ignited, low emission gas engines and have digester gas burning experience. All can be fitted with exhaust after-treatment equipment to control NOx and CO emissions to current and future required levels if required. In addition, the existing engines are relatively new Waukesha low emission engine generators. These engines are < 35% efficient as they are a slightly older generation engine and do not have as sophisticated of control systems. They too can be equipped with exhaust after-treatment equipment to meet current/future emission requirements.

Two alternatives were identified using reciprocating engine technology for each process configuration; the first, continuing to utilize the existing engine generators and the second, utilize a new GE/Jenbacher engine generator unit.

3.2 Microturbine

Microturbines are essentially small gas turbines operating at very high rpm to produce power and heat.

Microturbines are extremely low emission technologies and typically do not require an air permit for operation.

Microturbines evaluated typically convert 29 percent to electrical output (as a percentage of fuel input energy) and 29 percent to recoverable exhaust heat for a total overall efficiency of approximately 58 percent.

There are currently several commercial manufacturers offering microturbine power generating units. Only two of these units (FlexEnergy formally known as Ingersoll Rand and Capstone) have experience utilizing digester gas as a fuel source. FlexEnergy offers 250 kW modular units. The Capstone units come in 30, 65, and multiples of 200 kW sizes.

Ingersoll Rand and Capstone have shipped worldwide more than 100 units operating on both natural gas and digester gas. Several dozens of 30 kW and 70 kW units and two 250 kW units are operating on digester gas. Two 250 kW units are in operation on a medium BTU gas at a Oil/Gas Producer in Grand Isle, LA and eight 250 kW units have recently been sold for operation on a medium BTU gas in both the United States and China.

One alternative was identified for each of the process configurations utilizing new Flex Energy microturbine units.

3.3 Fuel Cells

Fuel cells utilize the hydrogen present in the methane-rich digester gas as a fuel source in an electrochemical process. The process converts the elemental carbon and hydrogen from the methane into carbon dioxide and hydrogen and in the process releases electrons, which are captured as direct current (DC) electricity.

The fuel cells evaluated typically convert, as a percentage of fuel input power, 47 percent to electrical output, and 22 percent to recoverable exhaust heat for a total overall efficiency of approximately 69 percent.

Two manufacturers currently offer fuel cells for large-scale power generation, United Technologies Corporation (UTC) and Fuel Cell Energy (FCE). Both manufacturers have provided fuel cells for applications utilizing digester gas; however, only FCE has units currently in operation. Many of these units operating on biogas are located in California. FCE utilizes a more efficient fuel cell technology than UTC, providing 47 percent fuel-to-

electricity efficiency versus UTC's 37-40 percent. Due to the higher efficiencies and additional experience utilizing digester gas, only FCE units are considered for this evaluation.

As an electrochemical process, fuel cells produce significantly less pollutant byproducts than combustion technologies. Fuel cells have approximately 1/100th the emissions generated by engine-generators.

One alternative was identified for each of the process configurations utilizing a new Fuel Cell Energy fuel cell.

3.4 Alternative Benefit Comparison

A summary of the advantages and disadvantages for the existing cogeneration system and three technology alternatives is included in Table 5.

Table 5 Alternative Benefit Comparison Cogeneration Assessment SLCDPU

Alternative	Advantages	Disadvantages
Alternatives 1, 2, & 3 - Existing Cogeneration System	• No change in operation	• Does not take advantage of all the digester gas available onsite or reduce facility carbon footprint
Alternative 4 - Conventional Reciprocating Engines	• Proven technology utilizing biogas for over 40 years • Newer generation engines have very high efficiency • Newer engines can easily meet new strict emission regulations	• Requires dedicated building for sound and weather protection • Frequent operator attention required for operations and maintenance • Requires fuel treatment
Alternative 5 - Microturbine	• Ultra low emissions • Simplified electrical interconnection • Low operator attention for operations and maintenance	• Very lowest electrical efficiency • Requires extensive fuel treatment
Alternative 6 - Fuel Cell Generator Unit	• Ultra Low emissions • Highest efficiency • Simplified electrical interconnection • Low operator attention for operations and maintenance	• Highest O&M costs • Highest capital costs • Requires extremely reliable and robust fuel treatment

4.0 FUNDING SOURCES

The following section outlines funding sources that may be available to SLCDPU to implement potential cogeneration alternatives. Table 6 summarizes applicable programs, depending upon how project procurement/development proceeds.

The applicability of the programs noted in Table 6 depends on many factors including procurement method and ownership and the technology utilized. Some of the programs are grants, some credits, and some loans - choosing the correct combination depends on many factors specific to the project.

Table 6 Funding Summary
Cogeneration Assessment
SLCDPU

Program	Source	Summary
Renewable Energy Production Incentive (REPI)	US DOE	Provides financial incentive payments of 1.5 cents per kWh of electricity produced for sale from renewable sources.
Renewable Electricity Production Tax Credit	US Govt.	Provides a 0.9 cents/kWh corporate tax credit for renewable energy systems (applicability is in question as digester gas fueled systems are not specifically addressed)
Commercial (non government) loan programs	Various	Various funding and loan programs exist outside of the above listed government sponsored programs. These are listed in the attached documentation and range from equipment secured loans to unsecured loans, to guaranty and subsidized loans
Renewable Energy Credits (RECs)	Various	Renewable energy credits can be sold for power generated utilizing renewable fuels. These energy credits (referred to as tags) are sold on an open market and for digester gas; fueled systems can represent income of approximately $0.0015/kWh. This amount varies with the market, which varies by area in the Country and type of technology utilized.
Clean Renewable Energy Bonds (CREBs)	Various	Various sources of bond financing exist which provide low/no interest financing to municipal entities for renewable energy projects. These allow municipal entities to take advantage of tax credits even though they cannot do so directly. Typically, fees of upwards of 5% of the bond funding proceeds apply for these bond funds.

4.1 Renewable Energy Credits

Renewable energy credits are a mechanism by which energy generated by renewable means can be valued and traded. Users who desire to “purchase” renewable power can purchase renewable energy credits for a certain amount of power that they will utilize.

Entities generating renewable power can get credit for this power (beyond the value of the power) on a $/kWh basis to the grid. The renewable energy credit is a means in which to track power, which has been generated, from renewable sources.

Renewable energy credits can be sold for power generated from renewable fuels. These energy credits (referred to as tags) are sold on an open market. This amount varies with the market, and is dependent upon area of the country and type of technology utilized. While the value is significantly less than newly generated power, even “tags” for power generated in past periods can be sold.

Typically, “tags” are sold through a broker specializing in these credits.

SLCDPU should pursue sale of “tags” for all of the power generated from the cogeneration system.

5.0 LIFE CYCLE COST EVALUATION RESULTS

To evaluate the benefits and costs of these alternatives, both the projected capital costs of the installation and the yearly operations and maintenance (O&M) costs were calculated. The evaluation takes into account the value of, or purchase of electrical power. The method selected for this analysis was to determine the total present worth of the project. Each alternative was then compared. Assumptions used for the life cycle cost analysis are shown in Table 7.

The results of the life cycle cost analysis are presented in Tables 8 and 9 for the current and BNR process digester gas projections.

Total project capital costs, including design and construction costs, for each alternative were estimated. Capital and life cycle costs are presented in Appendix B and C, respectively

5.1 Greenhouse Gas Emissions

The Environmental Protection Agency (EPA) has proposed a mandatory monitoring and reporting rule, for facilities that emit greenhouse gases (GHG) of more than 25,000 metric tons of CO_2 equivalent per year. The greenhouse gases include carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and fluorinated gases. The proposed rule does not affect wastewater treatment process emissions, but does cover onsite combustion sources. Table 10 summarizes the greenhouse gas emissions for each alternative. The GHG emissions are shown for the best-case gas production as a conservative measurement of emissions because more digester gas will be burned onsite. The onsite combustion emissions are the emissions that qualify for the EPA proposed rule. The GHG emissions for all alternatives are below the 25,000 metric ton per year minimum and the SLCDPU will not have to report their emissions. The total GHG emissions include both the emissions from onsite combustion and the electricity purchased offsite. Additionally, the use of the existing

engines was considered with and without natural gas supplementation. A review of all alternatives without natural gas usage is provided in Appendix D.

5.2 Qualitative Summary

Table 11 ranks the cogeneration alternatives utilizing weighted economic and non-economic criteria.

Table 7 Criteria and Financial Assumptions Cogeneration Assessment SLCDPU

Present worth year	2015
First year of evaluation	2016
Project duration, years	20
Inflation (capital costs)	1.80%
Inflation (fuel and electricity costs)	2.85%
Inflation (O&M costs)	1.80%
Gross discount rate	5.00%
Digester Gas LHV, Btu/scf	560
Existing engine availability percentage	90%
New engine availability percentage	90%
New microturbine availability percentage	95%
New fuel cell availability percentage	98%
O&M rate for existing engines alternatives $/kWh	$0.020
O&M rate for new engine alternatives $/kWh	$0.010
O&M rate for new microturbine alternatives $/kWh	$0.025
O&M rate for new fuel cell alternatives $/kWh	$0.037
O&M rate for fuel treatment system $/kWh	$0.010

Table 8 Life Cycle Cost Analysis – Current Process Configuration Cogeneration Assessment SLCDPU

Project Alternative	Description	Estimated Project Cost(1) ($ Million)	Total Present Worth of Costs(2,3) ($ Million)	Total PW of Net Benefit Compared to Existing Cogeneration ($ Million)
1	Existing Cogeneration – Run 1 Engine	0	8.3	-0.8
2	Existing Cogeneration – Run 2 Engines w/o NG purchase	0	7.5	-
3	Existing Cogeneration – Run 2 Engines w/ NG purchase	0	8.4	-0.9
4	New 1400 kW Engine	9.4	14.9	-7.4
5	New 1000 kW Microturbine	6.7	15.2	-7.7
6	New 1400 kW Fuel Cell	12.1	20.9	-13.4

Notes:
(1) This includes estimated construction cost plus associated costs for engineering, administration, and construction management.
(2) This includes overall treatment plant energy and O&M costs for each individual alternative.
(3) This does not include future potential regulatory surcharges based on future greenhouse gas and emission regulations.

Table 9 Life Cycle Cost Analysis – BNR Process Configuration
Cogeneration Assessment
SLCDPU

Project Alternative	Description	Estimated Project Cost(1) ($ Million)	Total Present Worth of Costs(2,3) ($ Million)	Total PW of Net Benefit Compared to Existing Cogeneration ($ Million)
1	Existing Cogeneration – Run 1 Engine	0	10.1	-
2	Existing Cogeneration – Run 2 Engines w/o NG purchase	N/A(4)	N/A(4)	N/A(4)
3	Existing Cogeneration – Run 2 Engines w/ NG purchase	0	12.7	-2.6
4	New 850 kW Engine	8.6	17.3	-7.2
5	New 666 kW Microturbine	5.3	15.9	-5.8
6	New 900 kW Fuel Cell	10.7	22.2	-12.1

Notes:
(1) This includes estimated construction cost plus and associated costs for engineering, administration, and construction management.
(2) This includes overall treatment plant energy and O&M costs for each individual alternative.
(3) This does not include future potential regulatory surcharges based on future greenhouse gas and emission regulations.
(4) Alternative 2 not viable as insufficient digester gas to run both existing engines without natural gas purchase

Table 10 Greenhouse Gas Emissions Cogeneration Assessment SLCDPU

Project Alternative	Current		BNR	
	GHG Emissions from Onsite Combustion(1), CO_2 Equivalent value (metric-ton/year)	Total GHG Emissions(2), CO_2 Equivalent value (metric ton/year)	GHG Emissions from Onsite Combustion(1), CO_2 Equivalent value (metric-ton/year)	Total GHG Emissions(2), CO_2 Equivalent value (metric ton/year)
Existing Cogeneration (1 Engine w/o NG)	5,200	8,700	3,800	9,000
Existing Cogeneration (2 Engines w/o NG)	5,100	7,000	N/A	N/A
Existing Cogeneration (2 Engines w/ NG)	5,800	7,100	5,900	8,500
New Engine	5,100	5,900	4,400	8,900
New Microturbines	5,100	7,800	6,000	11,400
New Fuel Cells	7,500	7,800	8,500	12,400

Notes:

(1) CO_2 equivalent emissions from CH_4, CO_2, and N_2O produced onsite from combustion of digester gas and natural gas through cogeneration or by flaring the gas.

(2) CO_2 equivalent emissions from CH_4, CO_2, and N_2O produced from onsite combustion and the emissions produced from electricity generation by Rocky Mountain Power.

Table 11 Cogeneration Study Alternatives - Rating Matrix
Cogeneration Assessment
SLCDPU

Ranking Criteria		Present Worth of Life Cycle Cost[3]	Energy/Green-house Gas Regulations	Protection Against Energy Price Volatility	Reliability/ Redundancy	O&M Complexity	Length of Permit Application Process	Proven Biogas Cogeneration Technology	Footprint	Efficient Use of Resources	Total Weighted Score[1]
Weighting Factor[2]		5	5	3	4	4	3	3	3	5	–
Project Alternative	Description										
1	Existing Cogeneration (1 w/o NG)	4	2	4	5	4	5	5	4	4	140
2	Existing Cogeneration (2 w/o NG)	4	2	4	4	4	4	5	4	3	128
3	Existing Cogeneration (2 w/ NG)	3	2	3	4	4	4	5	4	5	130
4	New Engines	2	4	4	4	5	3	4	4	3	126
5	New Microturbine	1	2	2	4	3	4	3	3	2	89
6	New Fuel Cell	1	4	3	3	2	4	2	2	3	93

Notes:
(1) Total Weighted Score equals the sum of each criteria's weighted factor multiplied by its individual ranking for each respective alternative; highest value is most desirable/beneficial, lowest value is least desirable/beneficial.
(2) Weighting Factors: 5 - More Important, 1 - Less Important.
(3) Present worth of life cycle costs are based on the worst case digester gas projection as shown in Table 8 for Current Process Configuration.

6.0 RECOMMENDATIONS

The recommendation of this cogeneration assessment for SLCDPU is to continue to use the existing engines with either the current treatment process or a new BNR process. New equipment reduces emissions and increases efficiency but results in higher life cycle costs.

Additional recommendations include the following:

- Renegotiate the terms of the contract with the power utility to allow for export of excess power. This would allow for operation of both existing engines and reduce the quantity of flared digester gas.
- Consider a fats, oils and grease (FOG) collection program in the city and add this waste to the digesters, which currently have spare capacity. FOG collection programs in other locations have led to increase in digester gas production of 25-50 percent.
- An alternative outside the scope of this study that could be considered is using digester gas for fleet vehicles.

Note:

A complete copy of Carollo Engineers' report Appendices A-D, is included in the Phase II Technical Memorandum dated December 14, 2014.

Appendix C

Phase II Scoring and Ranking Matrix

Salt Lake City Renewable Energy Plan
Detailed Site Evaluation and Project Ranking

Category			Site						Interconnection		Zoning	Permitting	Generation				Sustainability						Weighted Average Scoring
Weight			30%						15%		15%	10%	20%				10%						
Criteria			Compatibility with existing site use	Infrastructure	Site access	Physical Characteristics	Public safety	Public Nuisance	Access	Ease of interconnection	Local Zoning Standards	Local State Federal	Resource Quality	Power Resiliency and reliability	Electricity Supply	Electricity End Use	Renewable Energy	Energy sustainability	Climate Change	Leadership and Education	Economic Development	Public Policy	
Description			Ability to integrate renewable energy project with existing DPU site use	Extent to which project can be constructed with existing infrastructure at the site.	Site access for construction and , interconnection activities	Are there obvious physical site constraints, e.g. topographical, geologic, property line encroachment, proximity to scenic, recreation or environmentally sensitive areas?	Does project location create a potential safety risk to the public?	Does proximity of the project to residences or other established uses in the vicinity pose a potential public nuisance (visual, degradation of property value, noise etc.	Extent to which project site provides either direct access to DPU load or the distribution system.	Complexity and costs of meeting distribution system interconnection requirements including costs of studies and complexity and costs of additional equipment required for interconnection	Extent to which renewable energy project is compatible with existing zoning ordinances.	Permitting Requirements and Complexity	Quality of RE resource at the site	Will the project increase DPU energy system resiliency to power outages and reliability of the delivery of DPU services?	Extent to which ptential RE project will serve load at the project site	How is the project likely to contribute to offsetting DPU's largest and most critical end use loads?	Will this project contribute to meeting SLC's renewable energy goals?	Extent this project will contribute to reducing reliance on fossil generated electricity and demonstrate efficient use of energy	Extent to which project will contribute to meeting SLC's GHG goals.	Will this project enhance opportunities to educate SLC citizens and improve public perception of DPU and the City's commitment to clean energy and air?	Potential to enhance opportunities for local clean energy vendors and jobs.	Will this project demonstrate leadership (leading by example) or remove regulatory or policy barriers that will lead to an increase in the deployment of distributed renewable energy systems in SLC	
Weight			20%	15%	15%	15%	15%	20%	50%	50%	100%	100%	25%	25%	25%	25%	20%	20%	10%	15%	15%	20%	
Project Site																							
Project No. 1	Mountain Dell Dam	Hydroelectric	2	2	2	3	5	5	5	3	5	5	5	0	5	5	5	5	5	4	3	5	4.0150
Project No. 2	Terminal Park Reservoir	Roof Mount PV	5	4	5	4	5	5	5	3	1	1	5	0	5	1	5	3	3	5	5	5	3.2500
Project No. 3	Morris Reservoir	Roof Mount PV	5	2	5	4	4	3	5	3	1	4	5	0	3	5	5	3	4	4	3	5	3.3600
Project No. 4	South Lift	Ground Mount PV	5	3	5	5	3	4	5	3	5	5	5	0	3	5	5	3	4	4	3	5	4.1650
Project No. 5	15th East Reservoir	Roof Mount PV	5	5	4	3	5	4	5	3	5	5	5	0	3	5	4	4	5	5	4	4	4.2300
Project No. 6	B35-R18	Microhydro	2	2	1	2	3	5	3	3	4	5	2	0	0	0	5	0	0	1	3	5	2.6900
Project No. 7	B11-R13	Microhydro	2	2	3	3	5	5	3	3	4	5	2	0	0	0	5	0	0	1	3	5	2.9150
Project No. 8	C41-R20	Microhydro	2	2	1	2	3	5	3	3	4	5	2	0	0	0	5	0	0	1	3	5	2.6900
Project No. 9	Victory Rd Reservoir	Roof Mount PV	5	5	2	3	5	5	5	3	1	3	5	0	2	5	5	3	4	3	3	5	3.3150
Project No. 10	Concord Lift	Ground Mount PV	5	3	2	2	2	2	5	3	0	3	1	0	3	5	5	3	4	3	2	4	2.5300
Project No. 11	Baskin Rreservoir	Roof Mount PV	4	2	5	1	5	5	2	2	1	5	5	0	3	5	5	3	4	3	4	5	3.1300
Project No. 12	Wilson Reservoir	Roof Mount PV	5	4	2	4	3	2	5	3	5	2	5	0	3	5	5	3	4	3	3	5	3.5950
Project No. 13	6200 S. Well	Ground Mount PV	5	4	4	3	3	5	5	4	3	4	1	0	1	5	5	2	3	3	2	4	3.4300
Project No. 14	D74-DV-1	Microhydro	2	1	5	3	3	5	1	1	5	5	3	0	0	0	5	0	0	1	3	5	2.7700
Project No. 15	Greenfield Village Well	Ground Mount PV	5	4	5	3	4	5	3	1	5	1	5	0	1	5	5	3	3	2	3	4	3.3650
Project No. 16	Sorenson Fitness Center	Roof Mount PV	5	4	5	5	5	5	5	4	5	5	5	0	3	3	3	3	3	4	4	4	4.2800
Project No. 17	SLC DPU Building	Roof Mount PV	5	4	5	5	5	4	5	4	5	5	5	0	4	3	3	3	3	4	4	4	4.2700
Project No. 18	SLCWRF Cogeneration	Biogas	5	5	5	5	5	5	5	5	5	5	5	0	5	5	5	3	3	4	3	5	4.6450
Project No. 19	500 South Trunlkine	Waste Heat Recovery	5	2	3	2	5	5	5	3	5	5	5	0	3	5	4	3	4	4	3	5	4.0250

Appendix D

Rate Schedule and Financing Primer
Utah Clean Energy

Utah Clean Energy

Rate Schedule and Financing Primer

Salt Lake City Renewable Energy Plan

Sophie Hayes and Kate Bowman
November 1, 2014

Contents

Appendix A: Summary of Available Rate Structures:

Electric Service Schedule 31: Partial Requirements Service – Large General Service – 1,000 kW and Over

Schedule 31 provides supplementary, backup and maintenance power to customers who obtain any part of their regular electric requirements from self-generation. This schedule is for customers who would otherwise qualify for Schedules 8 or 9 and who have on-site generation capacity between 1,000 kW and 15,000 kW.

This rate schedule was designed such that large “partial requirements” customers compensate the utility for being ready to serve as a “backup generator” during planned or unplanned outages and for supplementary power and energy not served by onsite generation. Under this tariff, customers contract with the Company for a specified amount of both supplementary power and backup power, which the Company agrees to have available for delivery to the customer.

All energy consumed under Schedule 31 is billed based on the pricing outlined in the customer’s general service schedule (Schedule 8 or 9). Power charges are determined based on the amount of supplementary power and backup power contracted for. Supplementary power is billed based on the power charges specified in the customer’s general service schedule. The power charge for backup power is based on the 15-minute period of highest on-peak usage. Backup power charges are reduced by half during scheduled maintenance, and there is no charge for off-peak backup power. Backup power is subject to a facilities charge, based on voltage. Any power above and beyond the total contracted power is considered Excess Power. Customers on this rate schedule also pay a monthly customer charge.

Although this rate schedule could be used to supply supplementary and backup power to a facility with on-site generation from renewables, it would only be practical if the customer’s generation were to track usage closely (or if usage could be scheduled to track generation). Schedule 31 anticipates that customers will be reducing or eliminating their usage of Company power the majority of the time and does not provide credits for electricity production in excess of usage, nor does it allow for resale of excess electricity; however, a facility taking service under Schedule 31 may still qualify as a “Qualifying Facility” (see below) and sell excess electricity back to the utility at wholesale “avoided costs” rates.

Full text of Schedule 31:
https://www.rockymountainpower.net/content/dam/rocky_mountain_power/doc/About_Us/Rates_and_Regulation/Utah/Approved_Tariffs/Rate_Schedules/Partial_Requirements_Service_Large_General_Service_1_000_kW_and_Over.pdf

Electric Service Schedule 32: Service from Renewable Energy Facilities

Schedule 32 was enabled by Senate Bill 12 (SB12), passed during the 2012 legislative session, but has not yet been finalized or approved by the Public Service Commission. This tariff is designed to serve large customers who would like to source a larger portion of their electric service from renewable energy resources than is currently available through the Company's resource portfolio. Using Schedule 32, large customers will be able to build or purchase energy from off-site renewable energy projects and pay Rocky Mountain Power for the delivery of such electricity to their facilities. Whether the renewable facility is owned by the customer or a third party, the customer and the renewable energy facility pay all of the costs and bear all of the risk of the renewable energy facility, and the facility is also responsible for all interconnection and integration costs. The customer must contract for more than 2. 0 MW of electricity delivery through Schedule 32.

As between a renewable energy facility and a Schedule 32 customer, electricity delivery is facilitated by two matching contracts: the Rocky Mountain Power will contract with the owner of the renewable energy facility to purchase electricity for resale to the customer (or in some cases more than one customer). Rocky Mountain Power will then sell that electricity to the customer or customers under renewable energy contracts with the same duration and pricing as the contract between the company and the owner of the renewable energy facility. Customers who want to develop their own renewable energy facilities may also contract for the delivery of electricity from their own off-site renewable projects through this tariff. Schedule 32 does not replicate virtual net metering and does not allow net metering.

This tariff is not yet finalized, however Utah Clean Energy will be able to provide additional recommendations regarding the utility of this tariff when it is finalized.

Full text of Senate Bill 12: http://le.utah.gov/~2012/htmdoc/sbillhtm/SB0012S01.htm

PURPA & Qualifying Facilities

The Public Utilities Regulatory Policy Act (PURPA) was passed in 1978 to promote greater use of domestic energy and renewable energy. PURPA established the "Qualifying Facility" (QF) class of electricity generating facilities to receive special rate and regulatory treatment, in the interest of promoting their development. QFs fall into two categories:

- Small Power Production Facilities, which are facilities of 80 MW or less whose primary energy source is renewable, including solar, hydro, wind, geothermal, or biomass resources.

- Cogeneration Facilities, which sequentially produce electricity and thermal energy (such as steam or heat) in a way that is more efficient than producing each independently.

One provision of PURPA requires that monopoly utilities purchase power from Qualifying Facilities that are able to provide electricity at rates equivalent to the utility's own "avoided cost." Avoided cost is defined as the incremental cost to an electric utility of electric energy or capacity, which, but for the purchase from the QF, the utility would have to generate itself or purchase from another source.

An owner or operator of a generating facility with a maximum net power production capacity of greater than 1 MW (1,000 kW) may obtain QF status by submitting a "self-certification" (no fee) or by applying for and obtaining Federal Energy Regulatory Commission (FERC) certification of QF status (fee required). To obtain QF status, facilities must file an electronic form through the FERC website. Facilities smaller than 1 MW do not need to certify in order to qualify as QFs.

Pursuant to PURPA, FERC adopted regulations relating to purchases and sales of electricity to and from QFs. These regulations afford state utility commissions wide latitude in setting avoided cost prices and procedures for purchases from QFs. In Utah, the Public Service Commission has approved two electric service schedules (Schedules 37 and 38) for implementing PURPA and FERC regulations.

Electric Service Schedule 37: Avoided Cost Purchases from Qualifying Facilities

Schedule 37 is available to owners of small QFs: either cogeneration facilities with a design capacity of one MW or less or Small Power Production Facilities with capacity of three MW or less. Avoided cost rates under Schedule 37 are published, "standard offer" rates. QFs enter into a written power sales contract with Rocky Mountain Power based on these published prices.

There is a cumulative cap of 25 MW of capacity for new resources contracted under this schedule before Rocky Mountain Power must update Schedule 37 rates. However, the Commission requires that Rocky Mountain Power update Schedule 37 rates once a year, so the 25 MW cap is effectively an annual cap.

Schedule 37 rates are published as non-levelized annual rates (winter on- and off-peak and summer on- and off-peak rates) or as 20 –year nominal (present value) levelized prices in cents per kWh. Current levelized prices for baseload and solar facilities are the following:

Levelized Prices (Nominal) for baseload (cogeneration) resources in cents per kWh:

On-Peak Energy Prices		Off-Peak Energy Prices	
Winter	Summer	Winter	Summer
4.589	4.819	3.859	4.089

Levelized Prices (Nominal) for fixed tilt solar resources in cents per kWh:

On-Peak Energy Prices		Off-Peak Energy Prices	
Winter	Summer	Winter	Summer
4.013	4.246	3.548	3.781

Levelized Prices (Nominal) for tracking solar resources in cents per kWh:

On-Peak Energy Prices		Off-Peak Energy Prices	
Winter	Summer	Winter	Summer
4.188	4.420	3.613	3.846

Full Text of Schedule 37: https://www.rockymountainpower.net/content/dam/rocky_mountain_power/doc/About_Us/Rates_and_Regulation/Utah/Approved_Tariffs/Rate_Schedules/Avoided_Cost_Purchases_from_Qualifying_Facilities.pdf

Electric Service Schedule 38: Qualifying Facility Procedures

Schedule 38 is available to owners of cogeneration QFs with capacity greater than one MW or renewable QFs with capacity greater than three MW, and can be used to make electricity sales to Rocky Mountain Power. Pricing under this schedule is not published; rather the Commission approved a pricing calculation method that Rocky Mountain Power uses to establish “indicative prices.” Large QFs negotiate pricing and contract terms directly with Rocky Mountain Power based on the supply characteristics of the QF and the utility resources it will displace.

Full text of Schedule 38:
https://www.rockymountainpower.net/content/dam/rocky_mountain_power/doc/About_Us/Rates_and_Regulation/Utah/Approved_Tariffs/Rate_Schedules/Qualifying_Facility_Procedures.pdf

Schedule 135: Net Metering

Net metering allows customers with on-site renewable energy facilities to connect to the electrical grid and receive credit for excess electricity that is produced, but not consumed, on-site. A "net meter" replaces the standard electrical meter and measures both the electricity supplied by the Company and the electricity which is generated by the customer and fed back to the electric grid. Electricity produced by the generating facility is first consumed onsite, but if the customer is not consuming electricity at the time it is being generated, excess electricity is sent back out to the electrical grid. The customer is billed for their 'net usage' over the course of a monthly billing period: the electricity supplied by the utility, minus the electricity supplied by the customer. Facilities which are eligible for net metering must use energy derived from one of the following to generate electricity:

- solar photovoltaic and solar thermal energy
- wind energy
- hydrogen
- organic waste
- hydroelectric energy
- waste gas and waste heat capture or recovery
- biomass and biomass byproducts, except for the combustion of
    - wood that has been treated with chemical preservatives such as creosote, pentachlorophenol, or chromated copper arsenate
    - municipal waste in a solid form
- forest or rangeland woody debris from harvesting or thinning conducted to improve forest or rangeland ecological health and to reduce wildfire risk
- agricultural residues
- dedicated energy crops
- landfill gas or biogas produced from organic matter, wastewater, anaerobic digesters, or municipal solid waste
- geothermal energy

Schedule 135 requires that generating facilities be located on or adjacent to the customer's premises, and are intended primarily to offset part or all of the customer's own electrical requirements. The customer-generator can aggregate its electrical requirements from multiple meters for the purpose of net metering, as long as all meters are located at or adjacent to the same property. Non-residential facilities can be up to 2 MW, although Schedule 135 is structured to encourage generating facilities to be sized such that average annual generation does not exceed average annual onsite load. Compensation for excess electricity production depends on whether a facility is considered a "small non-residential customer" or "large non-residential customer:"

- Small non-residential customers (who are otherwise billed under Schedule 15 or Schedule 23) are credited for excess electricity production with a cumulative kilowatt-hour credit. The credit will be deducted from the customer's kilowatt-hour usage on their next monthly bill, offsetting the customer's next monthly bill at the full retail rate of the customer's rate schedule. These credits roll over month-to-month until the customer's March billing period, after which remaining credits expire.
- Large non-residential customers (who are otherwise billed under Schedule 6, 6A, 6B, Schedule 8, or Schedule 10) are billed for their net electricity usage each month. In the event that generation exceeds usage in a given month, these customers can choose to receive credit for this excess electricity production one of three ways:

(1) Receive an average energy price per kilowatt-hour based on volumetric non-levelized energy prices in Schedule 37, using the following formula:

  0.38 x Winter On-Peak Energy Price
+ 0.19 x Summer On-Peak Energy Price
+ 0.29 x Winter Off-Peak Energy Price
+ 0.14 x Summer Off-Peak Energy Price
= total compensation for excess electricity production

(2) Receive a seasonally differentiated energy price based on non-levelized energy prices in Schedule 37, using the following formula:

Summer months (June – September):	*Winter months (October – May):*
0.57 x Summer On-Peak Energy Price	0.57 x Winter On-Peak Energy Price
+ 0.43 x Summer Off-Peak Energy Price	+ 0.43 x Winter Off-Peak Energy Price
= compensation for excess electricity production from Jun – Sep	= compensation for excess electricity production from Oct - May

(3) An average retail rate for the Electric Service Schedule applicable to the net metering customer as calculated from the previous year's Federal Energy Regulation Commission Form No. 1. Average retail rates from the most recently filed tariff (. effective September 2014) are the following:

Schedule 6: 8.2075¢ per kWh
Schedule 6A: 11.2772¢ per kWh
Schedule 6B: 8.5765¢ per kWh
Schedule 8: 7.2585¢ per kWh
Schedule 10: 7.1794¢ per kWh

The Utah Legislature originally required that electrical corporations offer net metering to their customers in 2002, through House Bill 0007. Utah's net metering law has since been modified several times, most recently during the 2014 legislative session through Senate Bill 208. Recent modifications to net metering legislation, in Utah and across the United States, have focused on the potential that net metering rate schedules do not adequately account for the costs and benefits of net metering customers and allow for cross-subsidization amongst ratepayers. Senate Bill 208 (2014) directed the Utah Public Service Commission (PSC) to determine whether costs incurred from a net metering program will exceed the benefits of the net metering program or vice versa, and to determine a just and reasonable charge, credit or ratemaking structure in light of the costs and benefits.

Rocky Mountain Power's net metering program is currently available to any customer who owns or leases a renewable generating facility, and capacity for the program is capped at 20% of the Company's 2007 peak demand. According to Rocky Mountain Power's 2014 Net Metering Customer Generation Report, only two percent of this capacity has been filled. Changes to the net metering tariff and Schedule 135 may have an impact on its value to self-generation customers in the future; however in its current form, Schedule 135 is the recommended tariff for customers with renewable generation who meet the net metering qualifications.

Full text of Schedule 135:
https://www.rockymountainpower.net/content/dam/rocky_mountain_power/doc/About_Us/Rates_and_Regulation/Utah/Approved_Tariffs/Rate_Schedules/Net_Metering_Service.pdf

Virtual Net Metering:

Virtual net metering allows parties to receive credit or compensation for generation from offsite renewable energy facilities. Similarly, a structure often known as "community net metering" can allow multiple parties to purchase shares of the output from a single renewable facility that is not physically connected to their property (or their meter). Virtual net metering and community net meting models allow individuals who are not good candidates for distributed solar (due to shading, or because they are renting their home or live in an apartment) to source electricity from renewable generation. Virtual net metering is not

currently authorized in Utah statute, and enabling a virtual net metering policy which allows kilowatt-hour per kilowatt-hour credits from an offsite solar facility to offset a customer's energy bill would require legislative action. Sixteen states and the District of Columbia have authorized some form of virtual net metering, although policies vary widely from state to state. Some variations simply authorize virtual net metering as an option that utilities may choose (but are not required) to offer, or restrict the policy to certain entities, certain utility service areas, or certain geographic areas. [1]

Utah's existing net metering statute has been the subject of heated debate in the last few months; recent modifications to net metering legislation, in Utah and across the United States, have focused on the potential that net metering rate schedules do not adequately account for the costs and benefits of net metering customers and thus allow for cross-subsidization amongst ratepayers. The Public Service Commission has launched a new docket, *14-035-114*, to investigate the costs and benefits of residential net metering, specifically. No previous docket has thoroughly investigated both the costs *and* the benefits of net metering, and the findings of Docket 14-035-114 will have an impact on the future of virtual net metering in Utah.

A few case studies of virtual net metering programs in other states provide examples of potential uses here in Utah:

Clean Energy Collective:

Clean Energy Collective (CEC) is a private company that funds, builds, and maintains medium-scale clean power facilities that are collectively owned by participating utility customers. Often referred to as "community solar" arrays, CEC projects can range from 500 kW to 50 MW in size and are sited in an ideal location and interconnected to the local utility's grid. CEC has 33 existing or ongoing projects, in 6 states (CO, MA, MN, NM, VT, WI) and 13 utility service territories. Although many of the utilities participating in CEC-built solar arrays are municipal or customer-owned co-operative utilities, several large investor-owned utilities have worked with CEC to develop solar projects, including National Grid (3 projects of 1 MW each in Massachusetts), NSTAR (2 projects of 1 MW each in Massachusetts), the Western

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[1] For a more in depth discussion of the types virtual net metering policies by state, see the following reports:
National Conference of State Legislatures, "Net Metering: Policy Overview and State Legislative Updates." <http://www.ncsl.org/research/energy/net-metering-policy-overview-and-state-legislative-updates.aspx>.
Institute for Local Self-Reliance, "Virtual Net Metering." <http://www.ilsr.org/virtual-net-metering/>.
ICLEI, "Aggregate Net Metering: Opportunities for Local Governments." <http://www.icleiusa.org/action-center/aggregate-net-metering-opportunities-for-local-governments>.

Massachusetts Electric Company (2 projects of 1 MW each in Massachusetts), and Xcel Energy (11 projects totaling just over 5 MW in Colorado).

Participating customers can purchase one or more panels in the array and receive compensation for the electricity produced by their solar panels. CEC claims to have superseded the constraints of net metering laws through partnerships with utilities and by using billing software that doesn't require legislation to distribute on-bill credits to customers. Instead, the electricity generated from the panels is sold directly to the utility through a mutually agreed contract (such as a Power Purchase Agreement or a Feed-in Tariff). The customer receives a portion of the monetary payment for the electricity, based on the panels they have purchased, via an on-bill credit. CEC uses a proprietary RemoteMeter™ system to calculate monthly bill credits for members in a way that integrates with utilities' existing billing system.

Connecticut and Virtual Net Metering

Connecticut has made virtual net metering available exclusively to state, municipal, and agricultural customers, who may host virtual net metering facilities and credit the generation towards their own accounts as well as other authorized accounts[2]. A virtual net metering facility can be up to 3 MW and must generate electricity using either renewable resources or combined heat and power. The virtual net metering facility can be owned by the host (a state, municipal, or agricultural customer), leased by the host, or owned by a third party and located on the host's property.

Virtual net metering hosts may aggregate all of the meters they own and receive credits towards their own accounts for electricity generated at the facility, and may also credit the electricity generated by the facility towards 'beneficial accounts' as long as they are within the same distribution company's service territory. A municipal or state customer can host up to 5 additional municipal or state accounts and 5 additional non-state or -municipal buildings if those accounts are critical facilities (including hospitals, police stations, fire stations, water treatment plants, sewage treatment plants, and public shelters) and connected to a micro grid. An agricultural customer can host up to 10 beneficial accounts as long as those accounts either use electricity for agricultural purposes, or are municipal or noncommercial critical facilities. When host customers produce more electricity than they consume, the excess electricity is credited to these beneficial accounts.

[2] More information from DSIRE: http://dsireusa.org/incentives/incentive.cfm?Incentive_Code=CT01R&re=0&ee=0.

Appendix B: Summary of Available Financing Options:

Utah Solar Incentive Program

The Utah Solar Incentive Program provides Rocky Mountain Power customers with a rebate for a portion of the initial cost of installing a solar photovoltaic system. Rocky Mountain Power administers the program, and Rocky Mountain Power customers can apply for the incentive during a two week period in January each year. Incentives are awarded based on a lottery system. The incentive rates and availability differ based on system size and customer class, and incentives decrease each year of the 5-year program. There is a cap on the incentive amount that is available for each category of project each year. For 2015, the available incentives and

Category		Small Non-Residential	Large Non-Residential
System Size*		≤ 25 kW*	> 25 kW ≤ 1,000 kW*
2015	Available Capacity	4,000 kW (AC)	8,500 kW (AC)
	Available Incentive	$0.90/Watt (AC)	$0.70/Watt (AC)
2016	Available Capacity	4,500 kW (AC)	10,000 kW (AC)
	Available Incentive	$0.85/Watt (AC)	$0.65/Watt (AC)

capacity are as follows:

*This does not refer to the maximum allowable size for the photovoltaic installation, but to the maximum amount of capacity which the incentive can be applied to. For example, although commercial installations may be up to 2MW, based on the net metering requirements, only half of a 2 MW system would be eligible to receive the incentive.

Recipients of the incentive must enroll in Rocky Mountain Power's Cool Keeper program, which allows Rocky Mountain Power to coordinate individual air conditioning units, reducing peak energy demand in the summer. Recipients of the incentive must also sign a portion of the Renewable Energy Certificates (RECs)[3] generated by the system over to Rocky Mountain Power, equal to 0.28 MW for each incentivized kW per year for 20 years. This amounts to approximately 20% of the RECs generated by a solar installation, and relinquishing ownership of the RECs may limit the rights to publically advertise an installation as a green power facility. This provision should also be considered carefully for any facility that will be pursuing LEED certifications or other green building certifications. The owner of the solar installation could choose to register the remaining RECs with a certified REC tracking organization (such as WREGIS) in order to sell them through REC broker. In order to prevent 'double-counting' RECS,

[3] The E.P.A. defines RECs as "The property rights to the environmental, social, and other nonpower qualities of renewable electricity generation." < http://www.epa.gov/greenpower/gpmarket/rec.htm>.

any given facility can only be registered once, so the owner of the installation would have to coordinate registration of their facility and divide ownership of the RECs in coordination with Rocky Mountain Power.

While applications for the Utah Solar Incentive Program can be very competitive, particularly within the residential category, the small non-residential category has been under-utilized in past years and presents an opportunity for smaller solar PV installations of less than 25 kW. In 2013, all of the small non-residential projects that applied for the incentive were offered capacity, and the total of these applications still did not reach the cap for the program in 2013. Rocky Mountain Power re-opened the application process in May to accept additional applications for this category. Approximately 1 MW of capacity was not ultimately used, and this capacity carried forward to be used in the future. Once again, in 2014, every small non-residential applicant was offered capacity. The Utah Solar Incentive Program is currently scheduled to run through 2017, and cannot be combined with any other Rocky Mountain Power incentive or grant programs, including Blue Sky Community Grants.

For more information and to apply: https://www.rockymountainpower.net/env/nmcg/usip.html

Blue Sky Community Grants

Rocky Mountain Power's Blue Sky program allows electric customers to choose to pay an additional fee on their bill to support renewable energy. A portion of these fees is used to provide grants for the construction of renewable energy installations (including solar PV, wind, geothermal, hydro, wave energy, and low-emissions biomass) through the Blue Sky Community Project Funds. Rocky Mountain Power accepts applications for Blue Sky Community grants on an annual basis, and any locally-owned, commercial-scale project of 10 MW or less may apply. Funding from the Blue Sky program is awarded considering the "reasonableness of the budget and funding request, the technology, project location, the complexity of the installation, community benefits, potential for public education, project readiness and the ability of the project sponsor to leverage other funding sources." Smaller projects (typically considered to be projects less than 25 kW) must be net metered, and larger projects may make other interconnection agreements with Rocky Mountain Power (although off-grid projects are not eligible.) Applicants may only receive funding through the Blue Sky program once every 3 years, and Blue Sky grants can only fund up to 60% of the total project costs. Although the majority of Blue Sky Community Grant awards have gone to solar projects, a few wind, low-impact hydro, and biomass projects have also received funding through this program.

The application window for 2015 has not been announced, but in 2014 Rocky Mountain Power accepted applications from April 9 to June 30, planned to announce awards by November 30 2014, and required that all projects be completed by December 2015. Blue Sky grants have funded numerous projects in Salt Lake City, including solar installations on churches; educational, arts, or cultural centers; Utah Transit Authority facilities; Salt Lake City School District buildings; and Salt Lake City's Plaza 349 building.

For more information and to apply: https://www.rockymountainpower.net/blueskyfunds

Power Purchase Agreements (PPAs)

A Power Purchase Agreement is a contract between two parties which outlines terms for the sale of electricity from one party to another. Power Purchase Agreements are commonly used as a financing mechanism for solar photovoltaic installations. Typically, a third-party developer builds, owns, and maintains a solar photovoltaic system for a host customer, and the host customer agrees to purchase electricity produced by the solar panels at a fixed price for a predetermined time period. The solar installation may be located on the host customer's roof or property, and many PPAs give the host customer the opportunity to purchase the solar equipment at depreciated rates after a certain time period. PPAs are an advantageous financial arrangement for non-profit organizations, local governments, and other entities who cannot take advantage of tax incentives because they allow the third-party developer to receive the tax benefits of the solar installation and pass the savings on to their host customer.

In 2010, House Bill 145 authorized Power Purchase Agreements for certain entities by clarifying that independent energy producers may sell electricity to non-profits, local governments, and schools without being considered a public utility and subjected to the regulation required of a public utility.

Full statute available at: http://le.utah.gov/code/TITLE54/htm/54_02_000100.htm

CPACE

Commercial Property Assessed Clean Energy (C- PACE) financing is an innovative way to finance energy efficiency, renewable energy, and water conservation upgrades to commercial buildings. Interested property owners select measures that achieve energy or water savings and receive 100% financing for their project, repaid as a property tax assessment for up to 20 years.

This assessment mechanism has been used nationwide for decades to access low-cost, long-term capital to finance improvements to property that meet a public purpose. During the 2013 Legislative Session, Senate Bill 221 authorized public agencies to issue bonds specifically for the purpose of a renewable energy or energy efficiency upgrades.

C-PACE financing is only available to private property owners, however it could potentially be used to finance clean energy or energy efficiency upgrades on a privately-owned facility in which the Department of Public Utilities rents space. Utah Clean Energy has assembled an Advisory Committee comprised of local governments, financial experts, attorneys, contractors, and businesses to identify best practices and implement pilot projects in 2015. Several local jurisdictions, including Salt Lake City, are currently coordinating to make C-PACE financing available to businesses in their jurisdiction.

Qualified Energy Conservation Bonds

Qualified Energy Conservation Bonds, or QECBs, are a debt instrument that enables qualified states, territories, and local governments to issue tax credit bonds with very low effective interest rates in order to fund energy conservation or renewable energy projects. QECB bonds were authorized by the Energy Improvement and Extension Act of 2008, and the American Recovery and Reinvestment Act (ARRA) of 2009 increased the volume cap for QECBs issued from $800 million to $3.2 billion. This total allocation has been divided amongst the States proportionally based on population, and further allocated to any “large local government” with a population greater than 100,000. Salt Lake City was allocated $1,908,605 and has not yet taken advantage of this allocation. Salt Lake County was allocated $6,392,683 and has used a portion of this allocation. A portion of the overall allocation was reserved to be held by the State of Utah, and $4,306,920 of this allocation remains. QECBs are intended to be used by public entities, however up to 30% of the allocation may be awarded to private entities.

Federal subsidies available for QECBs make them an extremely low-cost financing option. Issuers of QECBs can choose either to issue taxable bonds with a corresponding non-refundable tax credit to the holders of the bonds, or elect to receive a direct cash payment from the Department of Treasury that is equivalent to the amount of the non-refundable tax credit. Of these two options, the direct-pay QECB option is more popular. Both options create a lower effective interest rate for the borrower through Federal subsidies.

Individual jurisdictions may be able to pool their allocations in order to offer larger bonds and minimize the transaction cost of bond issuance per dollar financed. Individual jurisdictions can waive their sub-allocations, in which case they return to the state and can be made available to any entities in the state. Although there are no documented cases of local jurisdictions pooling their sub-allocations without state involvement, there are examples where local jurisdictions have pooled other tax-credit bonds. [4]

QECBs may be issued for "qualified conservation purposes" as defined in section 54D of the U. S. Internal Revenue Code (I. R. C. §54D), including capital expenditures:

- To reduce energy consumption in publicly owned buildings by at least 20%.
- To implement green community programs (including the use of grants, loans, or other repayment mechanisms to implement such programs).
- For rural development (including the production of renewable energy).
- For certain renewable energy facilities (such as wind, solar, and biomass).
- For certain mass commuting projects.

Cities and counties that have received allocations may create their own processes for approving projects within their jurisdictions, and the Governor's Office of Economic Development is charged with distributing Utah's allocation. Individual project developers must work either with their local jurisdiction or with the Governor's Office of Economic Development to arrange for the bond issuance. Applications for QECB from the state of Utah's allocation are available from the Governor's Office of Economic Development, and applications are accepted on a quarterly basis and then reviewed by the Private Activity Bond Authority Board at a subsequent Board Meeting. Upcoming application deadlines and board meeting dates are as follows:

Application Deadline Date	Meeting Date
November 24, 2014	January 14
February 23	April 8
May 26	July 8
August 24	October 14
October 26	December 9

For more information and to apply: http://business.utah.gov/programs/pab/energy-conservation-bonds/

[4] http://www. naseo. org/Data/Sites/1/documents/committees/financing/documents/qecb_memo_june13. pdf.

New Market Tax Credits:

The New Markets Tax Credit Program (NMTC Program) was established by Congress in 2000 to encourage investment in businesses and real estate projects located in low-income communities. The NMTC Program allows individual and corporate investors to receive a tax credit against their Federal income tax return in exchange for investing in low-income communities through Community Development Entities (CDEs), organizations with the primary mission of providing investment capital for low-income communities. The Community Development Financial Institutions (CDFI) Fund allocates tax credit authority to local CDEs through a competitive application process. CDEs can then offer tax credits to investors in exchange for equity in the CDE. This allows CDEs to make more flexible investments in distressed areas, at better interest rates than market rates. Investors receive a tax credit of 39 percent of their original investment, claimed over a period of seven years, in addition to the return on their investment in the CDE.

New Market Tax Credits can be used to fund renewable energy projects, although the structure of the project would be quite complicated. In order to take advantage of the tax incentives, a third-party developer could build, own, and maintain a solar photovoltaic system for a public entity. The Department of Public Utilities could then contract to purchase power from the privately owned facility through a Power Purchase Agreement.

Projects which emphasize a strong permanent job creation component are the most competitive and most likely to attract investor and CDE interest. Entities that are interested in utilizing New Market Tax Credits must work closely with a CDE and with potential investors to complete an application. Using New Market Tax Credits is administratively complicated and it may not be worthwhile to pursue New Market Tax Credits for projects costing less than $6-7 million. New Market Tax Credits should be considered for a larger project with good potential to create job growth. New Market Tax Credits could also be used to finance clean energy or energy efficiency upgrades on a privately-owned facility in which the Department of Public Utilities rents space.

New Market Tax Credit allocations can be awarded for renewable energy projects if they are located in census tracts which meet the following criteria designating them as ‘low income’ areas:

- The poverty rate is at least 20%
- Outside of a metropolitan area, the Median Family Income (MFI) does not exceed 80% of the statewide MFI
- In a metropolitan area, the Median Family Income (MFI) does not exceed 80% of the statewide MFI or the metropolitan area MFI (whichever is greater)

The following sites are located in census tracts which are considered low-income; the last three sites are not discussed in detail in this report, but are eligible for the NMTC program based on their location:

Site	Address
B11-R13	Approximately 1000 E 500 S, Salt Lake City
15th East Reservoir	Approximately 500 S and 1500 East, Salt Lake City
Salt Lake Water Reclamation Facility	1365 West 2300 North, Salt Lake City
500 South Sewer Line	Approximately 500 S and 200 E, Salt Lake City
Salt Lake City Sports Complex	645 S Guardsman Way, Salt Lake City
Sorenson Multicultural and Fitness Center	855 West California Avenue, Salt Lake City
Concord Lift Station	Approximately 1200 West California Avenue, Salt Lake City

For more information: http://www.cdfifund.gov/what_we_do/programs_id.asp?programID=5

Or contact:

Amy Rowland
Field Director
National Development Council
423 W 800 S
Ste. A-313
Salt Lake City, UT 84101
801-557-1537
arowland@nationaldevelopmentcouncil.org

USave Energy Fund:

The Utah U-Save Energy Fund program finances energy related cost reduction retrofits on existing equipment and installations for publically owned buildings by offering loans with low interest rates. A revolving loan mechanism allows borrowers to repay the loans using cost savings realized from the retrofits.

Projects which can be financed through U-Save include (but are not limited to):

- Energy efficient lighting systems
- High efficiency heating, ventilation and air conditioning systems
- Energy management systems
- Energy recovery systems
- Building shell improvements
- Load management projects
- Systems commissioning

Entities considering use of the U-Save Energy Fund are encouraged to evaluate renewable energy technologies, including rooftop solar water and space heating installations, solar photovoltaic, and small wind installations. Hydropower projects can also be eligible for U-Save Energy Fund loans. Projects financed by U-Save must have an average simple payback of five years or less, although borrowers may buy down paybacks to meet this five year limit. Loan repayments begin within sixty days of project completion and are due quarterly. The amount of annual loan repayment is based on the energy cost savings expected to result from the project (but does not change if projected savings differ from actual savings).

Applications for projects are accepted every 1 -2 years, based on the progress of the revolving loan fund. A new notice of loan funding availability will be issued in November, and applications will be accepted beginning in January. Entities who wish to apply for U-Save funds should begin by contacting the Office of Energy Development (OED), and will be asked to sign a Memorandum of Understanding agreeing to submit an Energy Assessment Report (EAR) outlining the proposed project within four months. The Office of Energy Development will reserve funding for the project during this time. When the EAR is complete, the entity applying for funding must submit the EAR along with a Loan Application, and the OED will review the application and approve it for funding. At this point, a Loan Agreement is issued guaranteeing funding for the Energy Conservation Measures outlined in the approved EAR, and the project can be started.

There are specific requirements and milestones projects must meet during the implementation process, including competitive selection of a design engineer and contractors or bidders. Applicants are expected to work closely with OED throughout the design and implementation of the project.

More Information: http://energy.utah.gov/funding-incentives/energy-financing/

Contact:

Teresa Pinkal
Energy Program Specialist
Utah Office of Energy Development
60 E. South Temple, Suite 300
Salt Lake City, UT 84111
801.538.8662

Questar ThermWise Business Custom Rebate Program

The Questar ThermWise Business Custom Rebate Program offers rebates to qualifying customers who complete natural gas saving energy efficiency projects that aren't covered by other existing Questar incentive programs. In order to qualify, the facility implementing the project must be on Questar's commercial General Service rate and must contact Questar Gas prior to purchasing or installing any equipment.

Appendix C: Franchise Agreement

The utility must have a current franchise agreement in order to receive certificates of public convenience and necessity, which are necessary for the utility's infrastructure projects. The city's franchise agreement is up for renewal in 2015 and provides an opportunity for the city to work with the utility on realizing some of its energy goals. Salt Lake City's 2015 Sustainability Plan identifies increasing renewable energy generation and market share as a key goal in the energy realm. This goal can best be achieved if the City is able to complete renewable energy installations in the most advantageous locations, where technical potential and interconnection possibilities with existing infrastructure are high.

Several of the projects described in this memo provide great opportunities for the generation of renewable electricity, and as large energy users the Department of Public Utilities and Salt Lake City both stand to gain (economically as well as in terms of environmental impact) from new sources of renewable energy. A renewed franchise agreement could create a framework though which Salt Lake City can maximize utilization of existing renewable energy sites by working with Rocky Mountain Power to coordinate the construction of new renewable energy resources with optimal locations and mutually advantageous benefits.

When choosing locations for new renewable energy projects, existing rate structures incentivize the DPU to site projects at specific facilities where energy usage is high. The facilities and properties where energy usage is high are not always ideal locations for renewable energy installations, due to space constraints, aging infrastructure, or shading. Were the Department of Utilities able to receive credits towards its general energy usage for the electricity from renewable electricity facilities located throughout its service territory, the DPU and Salt Lake City would have an additional incentive to build larger renewable projects, sited to maximize technical potential. These investments bring new resources to the grid offering all of the benefits associated with clean energy to all Rocky Mountain Power customers, including pollution-free, price-stable sources of electricity, optimally located to maximize energy production and minimize line losses.

Appendix E

Economic Cash Flow Model and Results
Energy Strategies

MEMORANDUM

TO: JEFF NIERMEYER, EXECUTIVE DIRECTOR
DEPARTMENT OF PUBLIC UTILITIES

DATE: DECEMBER 1, 2014

FROM : NICK TRAVIS, ENERGY STRATEGIES
DON HENDRICKSON

RE: SALT LAKE CITY RENEWABLE ENERGY Economic, Financial and Decision Analysis

Introduction

DPU and the Consulting Team identified project opportunities at 5 sites for economic evaluation. This section describes the approach, assumptions and results of the economic analysis. A single power generation technology was evaluated for each of four sites: 15th East Reservoir, B11-R13, Mountain Dell Dam, and Terminal Park Reservoir. Four power generation technologies were evaluated for the fifth site, the Salt Lake City Water Reclamation Facility (SLCWRF). One of the power generation options is to continue to use the existing reciprocating engine generators, the other three are: new reciprocating engines, micro turbines and fuel cells. Each of the four power generation technologies considered at the water reclamation plant was evaluated under two wastewater treatment process scenarios: 1) current process (primary clarification, trickling filters, aeration basins, secondary clarifiers and solids digestion) and 2) biological nutrient removal process. Except for at the B11-R13 and Terminal Park Reservoir sites, it was assumed that all generation could be used to offset site purchases from Rocky Mountain Power.

Economic Analysis

The economic analysis is performed using an annual cash flow model developed in Microsoft Excel. The model includes information on a "Business as Usual" or "BAU" electricity supply scenario, i.e. full requirements from Rocky Mountain Power (RMP) at all sites except partial requirements from RMP for SLCWRF which is assumed to operate one of its two existing engines with no natural gas supplementation. It also includes information on both running two existing engines at a time without and with supplemental natural gas and on each of the options to implement new power generation facilities at each site. The model provides an "incremental analysis", i.e. is used to compare the cash flows and greenhouse gas emissions associated with a comparative scenario to those with an alternative option over the economic life of the option. Refer to **Table 5-1** for a "Strategy Table" identifying key attributes of the options that were modeled.

The engineering firm conducting the study of each option was asked to provide the following information on each option:

215 South State Street, Suite 200 ✦ Salt Lake City, UT ✦ 84111 ✦ phone (801) 355-4365 ✦ fax (801) 521-9142

- In service date (constrained to be the first day of a fiscal year)
- "Overnite" capital cost in 2014$
- Percent of overnite capital cost expended in each fiscal year preceding the in service date
- Electric energy (kWh) produced by season and time period as defined under RMP rate schedules:
  - o Winter and Summer
  - o On-Peak Hours and Off-Peak Hours[1]
- Incremental non-fuel operating expenses.

Table 5-1. Options Considered in Economic Analysis

STRATEGY TABLE								
		Description						
Scenario/ Project Alternative	Who Conducted Study	Project Site	Site Type	Type of Wastewater Treatment Process	Type of Power Technology	Effective Generation Capacity kW	Economic Life (Years)	Use of Generation
BAU	NA	All Sites	General	Current	Existing Recip (Run 1)	1,320	20	Offset Grid Purchases
1	Sunrise	15th East Reservoir	Water Storage Reservoir	NA	Solar PV	274	30	
3	Sunrise	B11-R13	PRV in Transmission		Hydroelectric	190	50	Sell to Grid
4	Sunrise	Mountain Dell Dam	Surface Water		Hydroelectric	260	50	Offset Grid Purchases
5	Sunrise	Terminal Park Reservoir	Water Storage Reservoir		Solar PV	3,488	30	Sell to Grid
1_WRF	Carollo	SLC Water Reclamation Facility (WRF)	Wastewater	Current	Existing Recip (Run 1)	1,320	20	Offset Grid Purchases
2_WRF	Carollo				Existing Recip (Run 2 No NG)	1,320		
3_WRF	Carollo				Existing Recip (Run 2 with NG)	1,320		
4_WRF	Carollo				New Recip	1,390		
5_WRF	Carollo				Microturbine	844		
6_WRF	Carollo				Fuel Cell	1,330		
1_WRF_BNR	Carollo			Biological Nutrient Removal	Existing Recip (Run 1)	1,320	20	
3_WRF_BNR	Carollo				Existing Recip (Run 2 with NG)	1,320		
4_WRF_BNR	Carollo				New Recip	827		
5_WRF_BNR	Carollo				Microturbine	562		
6_WRF_BNR	Carollo				Fuel Cell	855		

[1] Carollo Engineers, Inc. provided estimates of annual generation which were allocated among seasons and hourly periods pro rata to the hours in each season/period.

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Refer to **Table 5-2** for a summary of assumptions regarding schedule, capital cost, generation and non-fuel operating expenses by option.

The dollar value assigned to generation is a key assumption. For all but two options, it is assumed that generation would offset grid purchases at the project site. In the cases of B11-R13 and Terminal Park Reservoir, generated power exceeds site requirements and would be sold back to Rocky Mountain Power (RMP).

In all instances, the energy generated (e.g. kWh) is assigned a value based on applicable Rocky Mountain Power rates. It is assumed that the solar PV and hydroelectric technologies offer no capacity value whether applied as an offset to purchases or exported to the grid. A capacity value is attributed to cogeneration at the wastewater plant. Specifically, it is assumed that on-site generation capacity at the SLCWRF displaces an equal amount of demand, but incurs demand charges associated with back-up power.

Table 5- 2. Schedule, Capital Cost and Non-Fuel Operating Expense Assumptions

STRATEGY TABLE																
SCHEDULE, CAPITAL COST, GENERATION, AND NON-FUEL OPERATING EXPENSE																
	Description															
							"Overnite" Capital Cost 2014$ Millions				Average Annual Generation, MWh					
							Total	Expenditure Schedule % of Total			Summer Season		Winter Season			
Scenario / Project Alternative	Project Site	Site Type	Type of Wastewater Treatment Process	Type of Power Technology	Effective Generation Capacity kW	In Service Date		FYE 2015	FYE 2016	FYE 2017	On-Peak	Off-Peak	On-Peak	Off-Peak	Total	Non-Fuel Operating Expense 2014 $000/Yr
BAU	All Sites	General	Current	Existing Recip (Run 1)	1,320		$0.0				519	1,662	1,439	1,583	5,203	$156
1	15th East Reservoir	Water Storage Reservoir	NA	Solar PV	274	07/01/16	$0.9	35%	65%		150	31	130	24	335	$13
3	B11-R13	PRV in Transmission		Hydroelectric	190	07/01/17	$1.0	5%	39%	56%	187	248	148	189	773	$15
4	Mountain Dell Dam	Surface Water		Hydroelectric	260		$1.6	5%	39%	56%	245	197	139	108	690	$19
5	Terminal Park Reservoir	Water Storage Reservoir		Solar PV	3,488		$11.3	15%	65%	20%	1,982	403	1,774	330	4,489	$150
1_WRF	SLC Water Reclamation Facility (WRF)	Wastewater	Current	Existing Recip (Run 1)	1,320		$0.0				519	1,662	1,439	1,583	5,203	$156
2_WRF				Existing Recip (Run 2 No NG)	1,320		$0.0				774	2,477	2,145	2,360	7,756	$233
3_WRF				Existing Recip (Run 2 with NG)	1,320		$0.0				883	2,825	2,447	2,691	8,846	$265
4_WRF				New Recip	1,390	07/01/15	$9.4	100%			904	2,893	2,505	2,756	9,058	$181
5_WRF				Microturbine	844		$6.7				632	2,021	1,750	1,925	6,327	$221
6_WRF				Fuel Cell	1,330		$12.1				1,037	3,318	2,874	3,161	10,390	$484
1_WRF_BNR			Biological Nutrient Removal	Existing Recip (Run 1)	1,320		$0.0				471	1,506	1,304	1,435	4,716	$141
3_WRF_BNR				Existing Recip (Run 2 with NG)	1,320		$0.0				883	2,825	2,447	2,691	8,846	$265
4_WRF_BNR				New Recip	827	07/01/15	$8.6	100%			538	1,720	1,490	1,639	5,387	$108
5_WRF_BNR				Microturbine	562		$5.3				420	1,345	1,164	1,281	4,210	$147
6_WRF_BNR				Fuel Cell	855		$10.7				667	2,133	1,847	2,032	6,679	$334

For those options where generation offsets purchases, the specific values assigned per kWh and kW of generation are based on current charges in the electric service schedule that applies to each site. The relevant schedules are 6A, 9, and 31. **Table 5- 3** indicates which schedule applies to each site and sets

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forth values assigned to generation based on relevant current rates. All charges under Schedules 6A, 9, and 31 are projected to increase at 2.85% per year.

Through 2037, sales of energy back to the grid from generation facilities at Terminal Park Reservoir are attributed annual prices that are set forth in RMP Electric Service Schedule No. 37. After 2037, an annual escalation rate of 2.85% is applied. The current annual price paid for customer generation under Schedule 37 is shown in **Table 5-3**.

Under certain options, available digester gas at the SLCWRF must be supplemented with natural gas to produce power and heat for the plant. Carollo estimated the average annual plant heat requirements and fuel balances including available digester gas and required supplemental natural gas. These amounts are shown for each SLCWRF option in **Table 5-4**. The fuel balances are different at the SLCWRF depending on the wastewater treatment process. The differences arise because of the variance in plant heat and power requirements and available digester gas under the BNR and current treatment processes.

Table 5-3. Electric Service Schedule and Relevant Current Rates by Generation Option

STRATEGY TABLE													
ELECTRIC SERVICE SCHEDULE AND CURRENT RATES BY GENERATION OPTION													
	Description												
							Value of Generated Power , 2014$						
							Summer Season			Winter Season			
							Energy Charges per MWh		Demand Charges per kW	Energy Charges per MWh		Demand Charges per kW	
Scenario / Project Alternative	Project Site	Site Type	Type of Wastewater Treatment Process	Type of Power Technology	Use of Generation	RMP Electricity Service Schedule	On-Peak	Off-Peak	Monthly On-Peak	On-Peak	Off-Peak	Monthly On-Peak	Calculated Average Cost of Grid Power per MWh
BAU	All Sites	General	Current	Existing Recip (Run 1)	Offset Grid Purchases	Various							$87
1	15th East Reservoir	Water Storage Reservoir	NA	Solar PV		RMP 6A	$117	$35		$98	$30		
3	B11-R13	PRV in Transmission		Hydroelectric	Sell to Grid	RMP 37	$31			$31			
4	Mountain Dell Dam	Surface Water		Hydroelectric	Offset Grid Purchases	RMP 6A	$117	$35		$98	$30		
5	Terminal Park Reservoir	Water Storage Reservoir		Solar PV	Sell to Grid	RMP 37	$31			$31			
1_WRF				Existing Recip (Run 1)									
2_WRF				Existing Recip (Run 2 No NG)									
3_WRF				Existing Recip (Run 2 with NG)									
4_WRF			Current	New Recip		RMP 31 (9)							
5_WRF				Microturbine									
6_WRF	SLC Water Reclamation Facility (WRF)	Wastewater		Fuel Cell	Offset Grid Purchases		$44	$28	$13	$34	$28	$9	
1_WRF_BNR				Existing Recip (Run 1)									
3_WRF_BNR				Existing Recip (Run 2 with NG)									
4_WRF_BNR			Biological Nutrient Removal	New Recip		RMP 31 (9)							
5_WRF_BNR				Microturbine									
6_WRF_BNR				Fuel Cell									

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Table 5-4. Heat Requirements and Fuel Balances by SLCWRF Generation Option

STRATEGY TABLE											
HEAT REQUIREMENTS AND FUEL BALANCES BY SLCWRF GENERATION OPTION											
	Description										
				WRF Plant Heat Requirements Average MMBtu				WRF Fuel Balances Average MMBtu			
Scenario / Project Alternative	Project Site	Type of Wastewater Treatment Process	Type of Power Technology	Total Plant Heat	Total Useful Produced by Cogen	Supple-mental Required from Boiler	WRF Plant Power Required Average MWh	Total Fuel Consumed	Digester Gas Available	Flared Digester Gas	Natural Gas Consumed
1_WRF	SLC Water Reclamation Facility (WRF)	Current	Existing Recip (Run 1)	26,250	26,310	301	10,858	66,151	97,637	31,486	-
2_WRF			Existing Recip (Run 2 No NG)		38,851	-		97,128		509	-
3_WRF			Existing Recip (Run 2 with NG)		44,727	-		111,818		-	14,181
4_WRF			New Recip		35,333	-		88,333		9,304	-
5_WRF			Microturbine		27,091	44		77,457		20,180	-
6_WRF			Fuel Cell		19,863	6,388		94,582		3,654	599
1_WRF_BNR		Biological Nutrient Removal	Existing Recip (Run 1)	25,477	23,844	1,634	13,029	61,651	59,672	-	1,979
3_WRF_BNR			Existing Recip (Run 2 with NG)		44,727	-		111,818		-	52,146
4_WRF_BNR			New Recip		21,012	4,466		58,111		1,850	289
5_WRF_BNR			Microturbine		18,025	7,452		60,816		418	1,562
6_WRF_BNR			Fuel Cell		19,863	-		71,555		-	11,883

Further assumptions with respect to non-fuel operating expense; inflation and escalation; plant operating parameters; greenhouse gas emissions coefficients; and cash flow treatment are captured in **Table 5-5**.

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Table 5- 5. Miscellaneous Assumptions

MISCELLANEOUS ASSUMPTIONS					
Description		Value	Unit	Source	Comment
Electricity and Fuel					
Electricity					
Renewable Energy/Green Power Credit	$	-	$/MWh	Energy Strategies	Sensitivity to GHG emissions value used instead
Natural Gas					
Delivered	$	5.12	per MMBtu/HHV	Energy Strategies	Starting value for FYE June 2015
Operation and Maintenance					
Water Recalamation Facility					
WRF - Existing Reciprocating Engine	$	0.020	$/kWh	Carollo Engineers, Inc.	Starting value for FYE June 2015
WRF - New Reciprocating Engine	$	0.010	$/kWh	Carollo Engineers, Inc.	Starting value for FYE June 2015
WRF - Microturbine	$	0.025	$/kWh	Carollo Engineers, Inc.	Starting value for FYE June 2015
WRF - Fuel Cell:300 kW unit	$	0.040	$/kWh	Carollo Engineers, Inc.	Starting value for FYE June 2015
WRF - Fuel Cell:1400 kW unit	$	0.037	$/kWh	Carollo Engineers, Inc.	Starting value for FYE June 2015
WRF - Fuel Treatment System	$	0.010	$/kWh	Carollo Engineers, Inc.	Starting value for FYE June 2015
Inflation & Escalation					
General Inflation		1.8%	% per year	2014 EIA AEO GDP Price Deflator Index, Reference Case	
Escalation Factors					
Capital Cost		1.8%	% per year	Energy Strategies	
Electricity					
Base Cost		2.85%	% per year	Energy Strategies	
Value of Generated Electricity		2.85%	% per year	Energy Strategies	
Natural Gas		4.0%	% per year	2014 EIA AEO, Reference Case, Mountain, Commercial	
Non-Fuel O&M		1.8%	% per year	Energy Strategies	
GHG Emissions Compliance Value		1.8%	% per year	Energy Strategies	
Plant Operating Parameters					
Boiler Plant Efficiency		80%	MMBtu Heat per MMBtu of Fuel	Carollo Engineers, Inc.	
Greenhouse Gas Emissions Coefficients					
Purchased Electricity					
Current		0.75	MTCO2e/MWh	SLC DPU	Starting value for FYE June 2015
EPA Target Reduction: 2030		27%		Energy Strategies	EPA Clean Power Plan Proposed Rule
Global Warming Potential					
CH4 Emissions		34	100 years	2013 IPCC AR5 p714	
N20 Emissions		298	100 years	2013 IPCC AR5 p714	
Natural Gas: Stationary Combustion					
CO2 Emissions		53.06	kg/MMBtu	The Climate Registry GRP V1.1, Table 12.1	
CH4 Emissions					
Engine Generators		0.5669	kg/MMBtu	The Climate Registry GRP V1.1, Table 12.1	
Turbines		0.0038	kg/MMBtu	The Climate Registry GRP V1.1, Table 12.1	
Fuel Cells		0.0009	kg/MMBtu	The Climate Registry GRP V1.1, Table 12.1	
N2O Emissions		0.0009	kg/MMBtu	The Climate Registry GRP V1.1, Table 12.1	
Total					
Engine Generators		0.0726	MTCO2e/MMBtu	Calculated	
Turbines		0.0535	MTCO2e/MMBtu	Calculated	
Fuel Cells		0.0534	MTCO2e/MMBtu	Calculated	
Digester Gas: Stationary Combustion/Boiler					
CO2 Emissions		53.06	kg/MMBtu	The Climate Registry GRP V1.1, Table 12.1	
CH4 Emissions		0.0009	kg/MMBtu	The Climate Registry GRP V1.1, Table 12.1	
N2O Emissions		0.0009	kg/MMBtu	The Climate Registry GRP V1.1, Table 12.1	
Total Boiler		0.0534	MTCO2e/MMBtu	Calculated	
Digester Gas: Stationary Combustion					
CO2 Emissions		52.07	kg/MMBtu	The Climate Registry GRP V1.1, Table 12.1	
CH4 Emissions		0.0009	kg/MMBtu	The Climate Registry GRP V1.1, Table 12.1	
N2O Emissions		0.0001	kg/MMBtu	The Climate Registry GRP V1.1, Table 12.1	
Total Stationary Combustion Other		0.0521	MTCO2e/MMBtu	Calculated	
Greenhouse Gas Compliance Value					
As Modeled	$	-	2014$/MTCO2e		
Sensitivity Case	$	25.00	2014$/MTCO2e		
Sensitivity Case	$	50.00	2014$/MTCO2e		
Cash Flow Treatment					
Type of Year		Fiscal		Energy Strategies	
Year End Date		June 30th		SLC DPU	
Discount Date		1-Jul-14		Energy Strategies	
Discount Rate		5.0%		SLC DPU	

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Applying the assumptions described above, the "incremental" analysis provides insight with respect to the benefits and trade-offs resulting when a course of action is pursued that is different from business as usual. The economic model measures changes (increases and (decreases)) in the following measures for each option versus the relevant business as usual scenario:

- On-site generating capacity, kW
- "Overnite" capital, 2014$ millions
- Average annual generation, MWh
- Non-fuel operating expense, 2014$ millions
- Average annual supplemental natural gas required, MMBtu
- Digester gas flared, % of total available
- GHG emissions, MTCO2e
- Present value cost of utility service, $ millions
    - As modeled assuming $0 per MTCO2e compliance cost
    - Sensitivity analysis at $25 and $50 per MTCO2e compliance cost.

Conclusions

Summary results with respect to these measures are shown in **Table 5-6**. The summary results indicate the following:

- If "cost effective" is defined as not increasing the cost of utility service, the solar projects are not cost effective and the hydroelectric projects become cost effective only assuming a significant cost is assigned to GHG emissions, e.g. between $25 and $50 per MTCO2e.
- There is an opportunity to generate a significant amount of power using solar PV technology at Terminal Park Reservoir. However, there is insufficient value assigned to power sold to the grid to recover the capital investment in such a facility. Even at the 15th East Reservoir where solar PV generation displaces purchases, the value attributed to GHG abatement would need to be in excess of $50 per MTCO2e to recover the invested capital.
- To the extent generation at the SLCWRF is currently being limited to one engine, there appears to be an economic opportunity to operate the existing two engines and consume more of the available digester gas, lowering the cost of utility service and GHG emissions. All new generation options considered for the SLCWRF entail significant incremental capital (between $5 and $12 million) and would result in an increase in the cost of utility service even if a value of $50 per MTCO2e is attributed to GHG emissions.

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Table 5-6. Economic Analysis - Summary Incremental Benefits and Trade-Offs

STRATEGY TABLE

ECONOMIC ANALYSIS - SUMMARY INCREMENTAL BENEFITS AND TRADE-OFFS

Scenario/ Project Alternative	Description						Increase (Decrease) vs. Comparison Scenario								Cost of Utility Service Present Value $Millions		
	Project Site	Site Type	Type of Wastewater Treatment Process	Type of Power Technology	Use of Generation	Scenario Used for Comparison	On-Site Generating Capacity kW	"Overnite" Capital 2014$ Millions	Average Annual Generation MWh	Self Generation to Total Required %	Non-Fuel Operating Expense 2014$ Millions	Average Annual Natural Gas Supplement Required MMBtu	Digester Gas Flared % of Available	Average Annual GHG Emissions MTCO2e	$0 per MTCO2e	$25 per MTCO2e	$50 per MTCO2e
BAU	All Sites	General	Current	Existing Recip (Run 1)	Offset Grid Purchases	No Cogen	1,320	$0.0	5,203		$156	0	-34%	-3,271			
1	15th East Reservoir	Water Storage Reservoir	NA	Solar PV		BAU	274	$0.9	335		$13			-252	$0.4	$0.3	$0.2
3	B11-R13	PRV in Transmission		Hydroelectric	Sell to Grid		190	$1.0	773		$15			-582	$0.6	$0.3	($0.1)
4	Mountain Dell Dam	Surface Water		Hydroelectric	Offset Grid Purchases		260	$1.6	690		$19			-520	$0.4	$0.1	($0.2)
5	Terminal Park Reservoir	Water Storage Reservoir		Solar PV	Sell to Grid		3,488	$11.3	4,489		$150			-3,381	$10	$9	$7
1_WRF	SLC Water Reclamation Facility (WRF)	Wastewater	Current	Existing Recip (Run 1)	Offset Grid Purchases												
2_WRF				Existing Recip (Run 2 No NG)		1_WRF	0	$0.0	2,553	24%	$77	0	-32%	-1,558	($1)	($2)	($3)
3_WRF				Existing Recip (Run 2 with NG)			0	$0.0	3,642	34%	$109	14,181	-32%	-1,233	($0)	($1)	($1)
4_WRF				New Recip			70	$9.4	3,855	36%	$25	0	-23%	-2,394	$6	$5	$4
5_WRF				Microturbine			-476	$6.7	1,124	10%	$65	0	-12%	-698	$6	$6	$6
6_WRF				Fuel Cell			10	$12.1	5,187	48%	$328	599	-29%	-3,184	$12	$11	$10
1_WRF_BNR			Biological Nutrient Removal	Existing Recip (Run 1)													
3_WRF_BNR				Existing Recip (Run 2 with NG)		1_WRF _BNR	0	$0.0	4,130	32%	$124	50,167	0%	1,061	$3	$3	$4
4_WRF_BNR				New Recip			-493	$8.6	671	5%	($34)	-1,689	3%	-549	$7	$7	$7
5_WRF_BNR				Microturbine			-758	$5.3	-506	-4%	$6	-417	1%	248	$6	$6	$6
6_WRF_BNR				Fuel Cell			-465	$10.7	1,964	15%	$193	9,904	0%	-729	$12	$12	$12

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References

Alpha Engineering and RB&G, Inc. 2014. Pre-Design Report for Mountain Dell Bypass and Hydro Project. Salt Lake City Department of Public Utilities.

U.S. National Renewable Energy Laboratory. Unknown. Solar Radiation for Flat-Plate Collectors Facing South in Salt Lake City, Utah. Available at http://rredc.nrel.gov/solar/old_data/nsrdb/1961-1990/redbook/sum2/24127.txt. Accessed on July 15, 2014.

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COUNCIL STAFF REPORT

CITY COUNCIL *of* SALT LAKE CITY

Item Schedule:
Briefing: April 23, 2019
Public Hearing:
Potential Action:

TO: City Council Members

FROM: Sam Owen, Policy Analyst

DATE: April 23, 2019

RE: FISCAL YEAR 2019-20 BUDGET,
DEPARTMENT OF PUBLIC UTILITIES,
Water, Sewer, Stormwater, and Street Lighting Funds

ISSUE AT-A-GLANCE
The Mayor's Recommended Budget for the Department of Public Utilities includes the Water, Sewer, Stormwater, and Street Lighting Enterprise Funds, totaling $298,017,775 for capital and operating expenses for the fiscal year 2020. Major budget items include system upgrades and expansions in response to aging infrastructure and new regulatory requirements, and 17 new staff positions related to the significant capital projects scheduled over the coming years.

These four Utilities are Enterprise Funds, operating more or less like businesses separate from the General Fund. Each fund generates revenue through user fees and has separate staff, materials and supply budgets and capital improvement programs. The management and administration of the four funds is all under the Department of Public Utilities.

SUPPLEMENTAL COMPONENTS
The Department also transmitted a proposed resolution that, if approved, would convey the Council's support for the new water reclamation facility (WRF). The resolution contains information about the project's budget as well. The resolution is required by the Utah Department of Environmental Quality (UDEQ) as a condition on its granting a regulatory variance for the current reclamation facility. The variance is required because regulatory compliance will only be achieved once the new plant is operational, by 2025. This item is Attachment 2.

Another proposal before the Council is the ordinance that would adopt a new rate structure for the Water, Sewer and Stormwater Utilities. The Council was briefed on the new proposed rate structure October 2, 2018. More information on this item is found beginning page 3 of this report. Attachments 3 and 4 pertain to this item.

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The Department also provided a final copy of its Renewable Energy Plan, which outlines goals and methods for carbon reduction across the Utilities. See Attachment 5. It is Council staff understanding that preparation of this kind of carbon mitigation/reduction planning was a major component of this year's Citywide budget proposal process.

Attachments
Attachment 1, Public Utilities proposed budget
Attachment 2, Water reclamation facility resolution of support
Attachment 3, Rate structure ordinance
Attachment 4, October 2018 Council rate study briefing
Attachment 5, Public Utilities renewable energy plan

Some of the other major items in this budget document include:

- **Rate increases:** 18 percent this year in the Sewer Utility, 10 percent in the Water Utility, and 10 percent in the Stormwater Utility. See more about these increases, beginning page 3. The increases are connected in part with the need to pay debt service for bonds issued to fund significant capital improvements over the next several years. The total impact to the average household utility bill would be approximately $5.34 per month.
- **Capital projects**: capital improvements planned for this year total $172,094,600. Notably, the Sewer Utility anticipates costs for the new Water Reclamation Facility (WRF) approaching $528,130,000. The Department has applied for federal funding through the Water Infrastructure Financing Innovation Act (WIFIA), which may result in favorable loans covering up to 49% of the cost of the new WRF. Furthermore, anticipated sewer collection system capacity upgrades are budgeted for $36,630,500 during fiscal 2020; $39,132,179 is projected in terms of actual expenditures on these projects during fiscal 2019. Over $100 million is budgeted for similar projects over the subsequent four fiscal years. These are Public Utilities Master Plan projects and not infrastructure projects directly caused by new development in the City's northwest quadrant, although the timelines have been adjusted for some Master Plan collection system projects based on new construction. See more about these upgrades below.
- **Personnel-related increases**: Personal Services will increase over fiscal 2019 by $2,505,057, which includes 17 total new full-time equivalents (FTEs), a 3 percent cost-of-living adjustment (COLA), and contemplates a 7 percent increase in insurance for medical premiums. The new employees are necessary to manage capital projects, increased operational needs, and to provide for succession of key positions. COLA adjustments are included in the proposed budget as a placeholder since Enterprise Fund budgets are reviewed by separate Advisory Boards, but will be adjusted based on the salary adjustment ultimately approved for City employees.

POLICY QUESTIONS

1. Northwest Quadrant- The Council may wish to ask the following questions in order to gain a more comprehensive understanding of the Utility projects in the Northwest Quadrant.
    a. Reports from the Administration, as available, on the status of the betterments to infrastructure improvements in the Northwest Quadrant as the State Prison construction proceeds. Per the contract between the City and State, monthly reports will be generated on the status and expense of betterments—the Council may wish to receive these reports or to otherwise request information about the progress of betterments and related costs as the process unfolds.
    b. Information of how costs the City will incur in construction of betterments on infrastructure improvements related to construction of the Prison will be recouped, so existing ratepayers are not unduly burdened. For example, where new private development in the Northwest Quadrant "taps into" or benefits from implementation of these betterments, would fees be assessed attendant to the improved capacity or service to help offset the costs over longer periods of time? This might be assessed through the application of impact fees, or through other means.
    c. Which Master Plan projects have been or will be expedited, in response to increased demands for service related to new development in the Northwest Quadrant. This would help with a more

comprehensive understanding of how new development in the Northwest Quadrant could be impacting existing customers through changes in rates for services.

2. The Council may wish for a more detailed explanation of impact fees and how they are being collected and applied within the Utility. At the time of this writing, 13 Master Plan projects budgeted for implementation during the coming fiscal year are expected to be eligible for impact fees; however, this has not yet been confirmed. Council Members may wish to request follow-up and ongoing status reports with regard to the Utilities' implantation of impact fees, especially in the context of a pending, new Impact Fees Facilities Report from the Department.
3. Community members in different parts of the City have asked about the Street Lighting Utility's replacement of older lights with LED technologies emitting light in "cooler" color spectrums, resulting in "bluer" light that some experience as appearing with higher intensity. Community members have pointed to efforts by other municipalities and admonitions from particular research items to move away from these "bluer" lights to adopt "warmer" lighting. Subsequent conversations with the Council have indicated energy-efficiency was to be an ongoing and forefront consideration in replacing Street Lighting. The existing Plan does not contemplate LED technology because it had not been developed at the time of the Plan's adoption.
    a. Council Members may also wish for an update on the Street Lighting Master Plan update, for which public engagement has commenced.
    b. The Council may wish to request more information about how and when constituent feedback has been incorporated in the process of replacements, both in terms of how lights are directed and how intensity is assessed and implemented.
    c. Council Members may wish to request that the Utility continue to look into how impact fees may or may not be applicable to Street Lighting projects, now or in the future.

MAJOR ITEM DETAIL

The percentages of proposed rate increases are calculated on the basis of a new proposed rate structure for the three utilities proposing increases (Water, Sewer, Stormwater). The new proposed rate structure was presented to the Council October 2, 2018. In conjunction with the current budget, the Department proposes implementation of that rate schedule. Attachment 4 provides detailed background on the rate structure. The rate structure change itself is revenue neutral. Attachment 3 is a proposed ordinance that would adopt the new rate structure. Information on the percentage changes for the proposed rate increases *without* adoption of the new rate structure is contained in Appendix D of the Administration's Public Utilities budget proposal.

Increases in rates for the current fiscal year, as well as the years subsequent, are in response to the bonding requirements and related debt service necessary to fund the replacement, maintenance and upgrades of aging and in some cases badly deteriorated infrastructure. The replacement, maintenance and upgrades of existing infrastructure will facilitate the ongoing use and availability of the Utilities' services for current customers.

- **Water Utility**

  In conjunction with implementation of the new rate structure, the proposed rate increase of 5 percent would impact an average resident's monthly bill by reducing it about 19 cents (little to no impact). Rates are projected to increase 5 percent each year through fiscal year 2022-23. Increases are timed based on capital project needs and the related bonding to finance the projects; as part of this, rates also increased 4 percent last fiscal year. The Utility anticipates bond proceeds of $35,196,000 and $44,490,000, in the fiscal years 2020 and 2021, respectively.

- **Sewer Utility**

  In conjunction with implementation of the new rate structure, the proposed rate increase of 18 percent would impact an average resident's bill by about $5.04 each month. Rates are projected to increase 18 percent for the subsequent two fiscal years, 15 percent for fiscal 2023 and 10 percent for fiscal 2024. Increases are timed based on capital project needs and the related bonding to finance the projects; as part of this, rates also increased 30 percent last fiscal year. The Utility anticipates bond proceeds of $55,307,000 and $39,218,000 in the fiscal years 2020 and 2021 respectively. (Projected rate increases

will continue to be evaluated with each year's budget and capital project schedule, and may change as needed.)

- **Stormwater Utility**
  In conjunction with implementation of the new rate structure, the proposed rate increase of 10 percent would impact an average resident's bill by about $0.49 each month. Dwindling cash reserves, stronger regulatory requirements, and infrastructure needs are drivers for the proposed rate increase. Additional rate increases of 10 percent, 9 percent, 6 percent and 5 percent are anticipated for the four subsequent fiscal years, respectively. The Utility anticipates bond proceeds of $14.5 million in fiscal 2020, in part to fund recently-initiated flooding mitigation projects and projects implemented in relation to road work funded by the recent general obligation bond.

- **Street Lighting Utility**
  This fund will not have a rate increase this year. The Utility reports energy savings related to LED lighting upgrades of about $300,000 from the current fiscal year, and anticipates similar outcomes in future years.

Capital projects:
Improvements planned in the Water Utility have to do with strengthening service capacity and updates to aging, critical infrastructure. Some items of note:

- Treatment Plant projects
  - Upgrades at the City Creek Water Treatment Plant are budgeted for $1,500,000 this year, reflecting necessary upgrades to critical infrastructure for the treatment and conveyance of drinking water. Improvements will total an estimated $1.5 million for the four subsequent years. Phase 2 of the City Creek Plant upgrades is budgeted for an estimated $30,000,000; that expense is not planned to begin before fiscal year 2024.
  - The Parley's Water Treatment Plant will undergo improvements this year totaling an estimated $2,050,000. The subsequent fiscal year 2021 budgets for $11,250,000 in capital costs for the plant and $2,000,000 in capital costs for each additional year through fiscal 2024. The Department estimates delayed capital costs at $158,000,000, of which $136,500,000 is designated for a new Parley's Water Treatment Plant. The remainder of those delayed capital costs relates to other projects at the facility. The delayed capital expenditures are costs that the Utility anticipates as being necessary, but hasn't planned to implement in terms of the projections in the fiscal year 2020 budget proposal.
  - The Big Cottonwood Canyon Treatment Plant will undergo improvements budgeted for $4,300,000, including $2,500,000 for a number of projects related to a plant rebuild. The plant rebuild is expected to incur further costs of $5,000,000 in the subsequent fiscal year 2021 and at least $2,000,000 annually through fiscal 2024. The Department estimates an additional $156,750,000 in delayed capital costs for this specific facility in the future. The delayed capital expenditures are costs that the Utility anticipates as being necessary, but hasn't planned to implement in terms of the projections in the fiscal year 2020 budget proposal.
- Improvements and electrical system upgrades at the 4th Avenue well near Canyon Road this year is budgeted for $3,000,000; rehabilitation of the Mountain Dell Dam for $2,165,000; and the hydropower project in Parley's Canyon budgeted for another $100,000 after last year's expenditure of $1,000,054.
- A water line on 1300 East Street ran $2,417,418 last year, and energy efficiency and renewable energy capital improvements are budgeted for another $200,000 (existing in-pipe turbines are scheduled to begin generating renewable power in 2021).
- The East-West aqueduct or water conveyance line from Park Reservoir to near Sugar House Park is budgeted for $10,000,000 this year and $10,000,000 in the subsequent year. The line is expected to expand capacity for service to the City's Northwest Quadrant (NWQ), and to provide capacity and redundancy for service elsewhere across the valley as well.

- Water meter replacements are estimated to cost $3,100,000 this year and will begin to allow meters to be read remotely. The meter replacement program is budgeted for $3,100,000 in years subsequent (through 2022-23). Upgrades are expected to reduce costs of meter reading and allow customers to access water consumption information in real time, thus supporting water conservation programs and enabling customers to identify property-side leakages promptly.

Improvements planned in the Sewer Utility have to do with updates and replacements to aging infrastructure, as well as expansions to service capacity. Some items of note:

- Approximately $6,380,000 in maintenance to the existing Water Reclamation Facility (WRF), along with $54,700,000 budgeted for initial construction and design related to the new WRF. As noted above, a total cost estimate for the new facility's construction approaches $528,130,000. The facility's construction is currently expected to be complete and operational in 2024 in order to meet a 2025 deadline based on federal and state nutrient discharge regulatory requirements. Issue periods of bonds used to fund the new construction are timed to coincide with the life of the WRF; payments on the bonds are timed to coincide with the customers who will most benefit during this 30-year period.
- Master Plan implementation of sanitary sewer system upgrades and expansions are budgeted for a combined total of $17,850,000 in the fiscal year 2020, and are budgeted for $19,500,000 and $17,000,000 in the two subsequent fiscal years, respectively. These projects will provide for needed capacity in areas where capacity is already an issue, particularly on the fast-growing west side of the City.
- Ongoing remediation for the Northwest Oil Drain Canal near the WRF will incur estimated costs of $150,000 (the budgeted $300,000 for last year was not spent) in the Sewer Utility.

The following are some items of note planned as part of the Stormwater Utility's capital improvements program for the fiscal year 2018-19.

- Collection mains upgrades on 1700 South from 2100 East to its intersection with Emigration Creek are budgeted for $1,100,000 in fiscal 2020 and another $1,100,000 in the following fiscal year. This is to address stormwater capacity on 1700 South during intense runoff, such as the summer rain events experienced in 2017. $211,811 had been expended for this project during fiscal 2019 at the time of the proposed budget's preparation.
- Updates to stormwater-related infrastructure on Gladiola Street from 500 South to 900 South will total an estimated $869,550; updates to storm drain infrastructure along 1300 East are budgeted for an estimated $1,200,00o during fiscal 2020; expenditures on the stormwater portion of this project during fiscal 2019 totaled $377,165.
- Water quality and riparian corridor improvements related to updates at the Stormwater Utility's 1000 North Lift Station are budgeted for $1,700,000; $88,652 was expended during fiscal 2019. This is a projected budget increase of about $700,000 for the project.
- Contributions by developers related to local area projects in the Stormwater Utility are expected to total $400,000. These can be in the form of property or other assets, as well.
- An update to the Drainage Master Plan is budgeted for $700,000. The existing Plan was completed in 1993 and outlines a number of upgrades to the Utility's infrastructure that have taken place since. A new look at the Plan will involve changing climate conditions and green infrastructure.

The Street Lighting Utility will:

- implement a program to provide matching grants for residents interested in certain kinds of privately-maintained lights. The grant is funded by an annual transfer of $20,000 from the General Fund.
- Other capital improvements in the Street Lighting Utility for the fiscal year 2020 are budgeted for $1,725,000 (down from an estimated $2,605,000 last year).
- 8,398 of the 15,662 lights the City maintains are now considered to be energy efficient; Street Lighting is in the seventh year of a ten-year plan to convert all the lights to "high energy efficiency lamps."
- Furthermore, $90,000 is budgeted for the ongoing Street Lighting Master Plan update this year.

Personnel-related increases:
The Department of Public Utilities has historically been conservative with personnel additions; for example, staff adjustments for a sample previous three fiscal years totaled 2 seasonal watershed-related additions, 2 new positions for sewer collection, and one new accountant position.

Proposed staff adjustments will allow the Utilities to manage capital projects, account for increased operational and regulatory needs, and provide succession for key positions. This year's additions total 17 new FTEs, expected to be distributed across the Utilities as follows (charts on next page).

Proposed Personnel Adjustments FY 2019- 2020

Administration	Water	Sewer	Stormwater	Street Lighting	Total
Engineering Technician I	-	-	-	1.00	1.00
Records Technician	0.80	0.10	0.10	-	1.00
Engineer II	0.50	0.25	0.25	-	1.00
Community & Engagement Coordinator	0.50	0.40	0.10	-	1.00
Sustainability Program Manager	1.00	-	-	-	1.00
					5.00
Water Reclamation Facility					
Pretreatment Inspector/Permit Writer		1.00			1.00
Pretreatment Senior Sampler/Inspector		1.00			1.00
FOG/Sewer Rate Program Supervisor		1.00			1.00
Office Technician II		1.00			1.00
					4.00
Maintenance					
Senior Water System Maintenance Worker	1.00				1.00
					1.00
GIS					
GIS Leak Detector II	0.50	0.30	0.20		1.00
					1.00
Engineering					
Engineering Technician II	1.00	0.50	0.50		2.00
Engineering Technician III	0.50	0.25	0.25		1.00
Engineer III	1.00	0.50	0.50		2.00
					5.00
Seasonal Positions					
Watershed Worker (2)	1.00				1.00
					1.00
Total New FTEs	**7.80**	**6.30**	**1.90**	**1.00**	**17.00**

Proposed Personnel Adjustments FY 2018/19

NEW JOBS REQUESTED FOR FY 18/19	Total FTEs	WATER	SEWER	STORM WATER	STREET LIGHTING
Prior Year 2018 Beginning Balance	408.50	262.53	112.43	31.12	2.42
1) PROJECT CONTROL SPECIALIST	1.00	0.50	0.38	0.10	0.02
2) DOCUMENT CONTROLS SPECIALIST	1.00	0.50	0.38	0.10	0.02
3) ENGINEERING TECHNICIAN III	1.00	0.50	0.38	0.10	0.02
4) ENGINNERING TECHNICIAN III	1.00	0.50	0.38	0.10	0.02
5) WATER RIGHTS ASSISTANT	1.00	0.50	0.25	0.25	
6) WATERSHED RANGER	1.00	1.00			
7) WATER PLANT OPERATOR II	1.00	1.00			
8) STORMWATER COMPLIANCE SPECIALIST	1.00			1.00	
9) STORMWATER TECHNICIAN	1.00			1.00	
10) PRETREATMENT INSPEC / PERMIT WRITER	1.00		1.00		
11) SENIOR WATER SYSTEM MAINTENANCE LEAD	1.00	1.00			
12) WATER SYSTEM MAINTENANCE OPERATOR II	1.00	1.00			
13) WATER SYSTEM MAINTENANCE OPERATOR I	1.00	1.00			
14) OFFICE FACILITATOR I - SHOPS PAYROLL (REPLACING VACATED BY HR)	1.00	0.74	0.18	0.08	
TOTAL NEW FTE'S	14.00	8.24	2.95	2.73	0.08
CHANGES DUE TO PAY REDISTRIBUTION:	1.00	2.00	0.05	-1.05	-1.00
TOTAL CHANGES TO FTE'S	14.00	10.24	3.00	1.68	-0.92
	33				
Projected Agency Total FTEs for 2019	422.50	272.77	115.43	32.80	1.50

OTHER BACKGROUND

Role of Impact Fees in upcoming major capital projects:
Related to this discussion of infrastructure improvements and betterments is the concept of impact fees. Impact fees are assessed and paid to the municipality by developing entities. They in turn go to pay for only the expansion, or “growth” component of what is required to provide a level of service, without going to pay for improving or otherwise modifying the existing level of service.

- In the Water Reclamation Facility (WRF):
  Impact fees cannot be used to help entities like the City’s Sewer Utility meet regulatory requirements. They cannot be used to pay for maintenance and operations of existing services, either. For example, the City’s construction of a new WRF is not expected to expand the current level of service, but is necessary to meet updated regulatory requirements and to replace aging and deteriorated infrastructure. The old plant is not operating at or beyond capacity, so the new plant is not a response to a need to expand capacity; the new plant is thus not considered eligible for funding through impact fees. However, the new plant is being constructed in such a way that expansions could be integrated. If these expansions of the facility were implemented to respond to an increased need for service capacity, construction of the expansions could be eligible for funding through impact fees at some time in the future. This is being more carefully evaluated in the Department’s updated Impact Fee Facilities Plan (IFFP).

  In addition to the Sewer Utility, the Water Utility has many such related expenses budgeted for the fiscal year 2020. The need for these capital improvements results from the need to update and replace aging infrastructure, and where this is the only impetus for the improvements, the projects will not be eligible for funding through impact fees. However, some conveyance projects such as the east-west aqueduct funded for a total $20 million in fiscal years 2020 and 2021 are expected to be eligible for impact fees because of directly accommodating an expanded need for service, especially with regard to new development in the Northwest Quadrant. The updated IFFP will identify the portion of Water Utility projects that are reasonably apportioned to growth.

  Capital improvements aside from the WRF in the Sewer Utility deal mostly with collection line system and capacity improvements on the City’s west-side, near the site of the current and future WRF. The Department of Public Utilities staff reports these Master Plan collection line system improvements are necessary to maintain the existing level of service and are in response to anticipated deterioration, again commensurate with aging infrastructure. Some of these projects will also increase capacity to accommodate growth. Where some of these projects are being placed on an accelerated timeline, funding such as the State no-interest loan, has been applied to ease the burden for ratepayers. Again, where maintenance or new regulation would be the only impetus for the projects, impact fees do not apply. However, some of the upgrades are expected to be eligible for funding through impact fees; specifics as to which in particular are pending at the time of this writing and will be incorporated in the Department’s work updating the IFFP.

- In the new State Prison:
  Commensurate with the impact fee model, developing entities are expected to pay the City’s Utilities for connections. For example, when a new apartment building is constructed, the developing entity would need to compensate the City at a certain predetermined rate for the number of Utilities-related facilities the development would provide (faucets, toilets, drains). However, the State as the developing entity responsible for implementation of the new Prison is not understood to be liable for providing these fees for connection. This is another aspect of how the State’s arrangement with the municipality is different from other situations.

Department of Public Utilities responses to Council staff email questions, April 2019

Service Level

There are no reductions in service for Public Utilities. In fact, service level is increasing for each of the utilities due to a number of factors, including:

1) Growth throughout the service area causing the need for increased development review, inspections, and engineering

2) The need to address aging water and sewer infrastructure

3) Additional regulatory requirements related to drinking water, stormwater, and sewer

4) The need for updated long term plans for each of the four utilities due to growth, climate change, and public values

5) The need for increased public engagement as we address the above issues

Changes in Programs or Projects from Last Year

Programming and project work continues at a similar level compared to the last fiscal year. There are some increases in programming and projects, including:

1) Design and construction of the new sewer treatment plant

2) Continued capital asset planning for critical infrastructure

3) Increases in stormwater programming and standard operating procedures as a result of managing the City's overall stormwater permit with UDEQ, and as a result of an audit conducted by UDEQ and USEPA in 2016

4) Development of a Fats Oils and Grease (FOG) program for the sewer utility

5) New state reporting requirements related to water use, water rights, and water source sizing

6) New vulnerability and emergency management requirements pursuant to the America's Water Infrastructure Act (passed October 2018)

7) New federal and state requirements anticipated this year regarding emerging contaminants

8) Expedited sewer, water, and stormwater pipe replacements to support the City's general obligation bond for roadway reconstruction

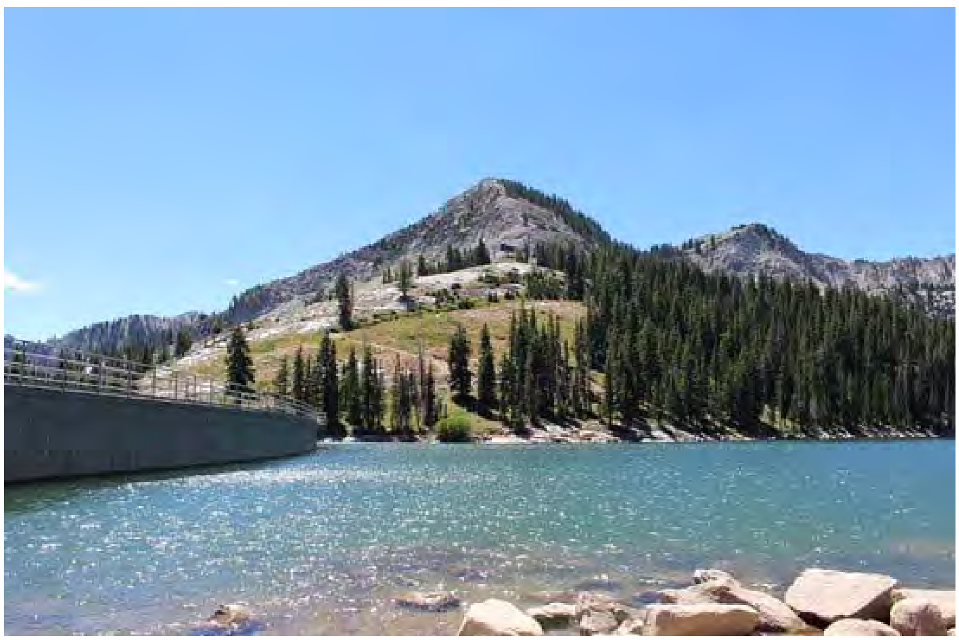
Vacant Positions

As of April 3, 2019, Public Utilities had a total of 24 vacant positions out of 422 positions. Of this total, the Water Utility has 16.5 FTE's, Sewer 6.5 FTE's, and Stormwater 1.0 FTE. The department intends to fill all vacancies, and the hiring process is ongoing.

Carbon Reductions

The Public Utilities budget for FY20 includes an appendix regarding the department's energy management and greenhouse gas mitigation projects. (See Appendix C of proposed budget document and Attachment 5).

PUBLIC UTILTIES ANNUAL
2019-20 FISCAL BUDGET PROPOSAL



April 3, 2019

WATER.— SEWER — STORMWATER — STREET LIGHTING
ENTERPRISE FUNDS
"SERVING OUR COMMUNITY, PROTECTING OUR ENVIRONMENT

SALT LAKE CITY DEPARTMENT OF PUBLIC UTILITIES
RECOMMENDED BUDGET FOR FISCAL YEAR 2020

Public Utilities

Salt Lake City Department of Public Utilities

I recommend for approval, rates, operations, personnel changes and the capital program as herein presented as the Salt Lake City Department of Public Utilities FY2020 Proposed Budget:

Laura Briefer, Director ______________________________

Public Utilities Advisory Committee (PUAC)

The PUAC concurs with and supports the Salt Lake City Department of Public Utilities FY2020 Proposed Budget presentation:

Ted Wilson, Chair ______________________________

Dated March 28, 2019

Table of Contents

Executive Summary FY 2020

Salt Lake City Department of Public Utilities (Department) is pleased to present its recommended budget for fiscal year 2019-2020 (FY2020). In addition to ongoing operations, the budget as presented includes funding for capital projects in the Water, Sewer, Stormwater, and Street Lighting Utilities to upgrade infrastructure, comply with regulations, and support growth.

As in previous years, a major focus of the Department's budget is in the rehabilitation and replacement of aging infrastructure. The Department has implemented a rigorous capital asset program that assesses the condition and criticality of water infrastructure. This proactive approach mitigates the risk of future failures of water, sewer, and stormwater infrastructure. Infrastructure failure and degradation can lead to public health, water supply, and environmental impacts. The largest planned projects are components of the new Water Reclamation Facility (WRF) that will be completed by 2024, improvements to the Big Cottonwood Water Treatment Plant, construction of a new water transmission line to serve downtown Salt Lake City, conceptual design for a new Public Utilities campus, and Water, Sewer, and Stormwater Utility infrastructure work necessitated by street improvements projects pursuant to the City's passage of a general obligation bond for that purpose.

Funding for capital projects in FY2020 will be generated through the issuance of revenue bonds and rate increases. Total bonding planned for FY2020 is $105,084,000. Proposed rate increases are 5% in the Water Utility, 18% in the Sewer Utility, and 10% in the Stormwater Utility. Street Lighting rates will remain the same. For future years, the Department is investigating the use of a federal low interest loan program for utility infrastructure as an additional funding source.

Summary of Utilities Fund Budgets

Utility Funds FY 2020	Operations	Capital	Debt	Fund Totals
Water	66,275,770	61,764,547	1,781,000	129,821,317
Sewer	21,024,164	107,064,500	13,456,000	141,544,664
Storm	7,172,368	13,472,149	1,306,000	21,950,517
Street	2,963,277	1,725,000	103,000	4,791,277
Total	$ 97,435,579	$ 184,026,196	$ 16,646,000	$ 298,107,775

The proposed budget includes the implementation of the structural rate changes to water and sewer rates pursuant to the Department's 2018 Comprehensive Water, Sewer and Stormwater Rate Study, and as presented to the Mayor and City Council. A proposed resolution adopting these structural changes is presented in Appendix A. As part of environmental regulatory requirements, the Utah Department of Environmental Quality is also requiring a City resolution approving the new WRF, which is also included in Appendix A.

The proposed budget includes the addition of 17 new full time equivalent (FTE) positions. These recommended positions are identified to assist the Department in meeting environmental requirements, implementing capital projects, and responding to economic and geographic growth within our service areas. The Department is also proposing two minor organizational structure changes to provide for succession planning and increased efficiency. Specific rationale is provided for these positions in Appendix B of this document.

As part of Mayor Biskupski's energy and climate initiative, the Department was requested to identify projects within the FY2020 Budget that demonstrate reductions in energy use through efficiency and/or renewable energy projects. Appendix C of this document summarizes the Department's Energy Management and Greenhouse Mitigation Projects and highlights several capital projects in each of the Department's four utilities that demonstrate energy and greenhouse gas reductions.

Budget Summary

The total proposed Department budget is $298,107,775, a 2.00% increase from the FY2019 amended budget of $292,268,301. The adopted budget was adjusted for FY2018 carryover encumbrances for open contracts and purchase orders. Those changes are reflected in the amended budget amount. The proposed operating budget of $97,435,579 is $2,054,167 or 2.15% higher than the current year. The increase includes the proposed new FTEs, a 3% cost of living adjustment (COLA) and a 7% increase in health insurance premiums. This also reflects a 3% rate increase for water purchased from the Metropolitan Water District of Salt Lake and Sandy (MWDSLS).

The proposed capital budget for FY2020 is $184,026,196. Debt service is anticipated to be $16,646,000, including the cost of issuing new debt during the year. Total debt service for FY2020 is increasing due to the cost of issuing new debt and the payment of the initial installment due on a state loan.

Proposed Department of Public Utilities Expenditures for FY 2019-20

Major Expenditure Categories	Adopted Budget 2018-2019	Amended Budget 2018-2019	Proposed Budget 2019-2020	Difference	Percent Change
Personal Services	35,516,006	35,516,006	38,021,063	2,505,057	7.05%
Materials and Supplies	6,346,750	6,362,247	6,733,060	370,813	5.83%
Charges for Services	49,321,529	53,503,159	52,681,456	(821,703)	-1.54%
Debt Service	8,317,000	8,317,000	16,646,000	8,329,000	100.14%
Capital Outlay	11,076,468	11,144,372	11,931,596	787,224	7.06%
Capital Improvements	123,721,000	177,425,517	172,094,600	(5,330,917)	-3.00%
Total	**$ 234,298,753**	**$ 292,268,301**	**$ 298,107,775**	**$ 5,839,474**	**2.00%**

The proposed budget includes projects rated as high priority in the Department's Capital Asset Program (CAP). The major capital improvement projects categories in the FY2020 budget are included in each Utility's budget description in the following sections. A detailed list of capital improvement projects is included in the cash flow summaries for each utility.

The Department's total anticipated revenues for FY2020 are $249,137,157, an increase of $109,630,160. Proposed rate increases are expected to generate $10,138,168 and the issuance of $105,084,000 in bonds account for the remaining increase. The Department intends to balance the budget utilizing $48,970,618 of reserves in all Utility funds. The reserves include the remaining balance of approximately $30 million from the 2017 bond issue.

Projected Department of Public Utilities Revenues for FY 2019-20

Revenue	Adopted Budget 2018-2019	Amended Budget 2018-2019	Proposed Budget 2019-2020	Difference	Percent Change
Operating Sales	123,992,012	123,992,012	134,130,180	10,138,168	8.18%
Interest	1,512,000	1,512,000	883,820	(628,180)	-41.55%
Permits	70,000	70,000	70,000	-	0.00%
Interfund Charges	2,449,985	2,449,985	2,475,157	25,172	1.03%
Other Revenues	833,000	833,000	833,000	-	0.00%
Impact Fees	1,400,000	1,400,000	1,900,000	500,000	35.71%
Contributions	3,895,000	3,895,000	3,761,000	(134,000)	-3.44%
Bond Proceeds	5,355,000	5,355,000	105,084,000	99,729,000	1862.35%
From (To) Reserves	94,791,756	152,761,304	48,970,618	(103,790,686)	-67.94%
Total	**$ 234,298,753**	**$ 292,268,301**	**$ 298,107,775**	**$ 5,839,474**	**2.00%**

Department revenues are generally predictable for all funds except water which is based on changes in seasonal use due to weather during the summer. A cooler, wetter summer and spring will reduce water demand and sales. The Department's water conservation rate structure and conservation education have and continue to be effective as customer's sensitivity to water usage has been proactive. The current water availability and storage reservoirs will have adequate coverage FY 2020, therefore water revenues are forecast on a normal or average expected usage.

Summary of Additional Proposed Positions

The Department currently has 422.50 FTEs and is proposing the following positions to meet identified needs. The Department is proposing adding 17 FTEs as shown in the following chart. A detailed description of these positions is provided in Appendix B.

Proposed Personnel Adjustments FY 2019- 2020

Administration	Water	Sewer	Stormwater	Street Lighting	Total
Engineering Technician I	-	-	-	1.00	1.00
Records Technician	0.80	0.10	0.10	-	1.00
Engineer II	0.50	0.25	0.25	-	1.00
Community & Engagement Coordinator	0.50	0.40	0.10	-	1.00
Sustainability Program Manager	1.00	-	-	-	1.00
					5.00
Water Reclamation Facility					
Pretreatment Inspector/Permit Writer		1.00			1.00
Pretreatment Senior Sampler/Inspector		1.00			1.00
FOG/Sewer Rate Program Supervisor		1.00			1.00
Office Technician II		1.00			1.00
					4.00
Maintenance					
Senior Water System Maintenance Worker	1.00				1.00
					1.00
GIS					
GIS Leak Detector II	0.50	0.30	0.20		1.00
					1.00
Engineering					
Engineering Technician II	1.00	0.50	0.50		2.00
Engineering Technician III	0.50	0.25	0.25		1.00
Engineer III	1.00	0.50	0.50		2.00
					5.00
Seasonal Positions					
Watershed Worker (2)	1.00				1.00
					1.00
Total New FTEs	**7.80**	**6.30**	**1.90**	**1.00**	**17.00**

Water Utility Enterprise Fund

Water Infrastructure Background

The Salt Lake City water system is one of the oldest and largest systems west of the Mississippi River with over 1,125 miles of 12" or smaller distribution lines, and more than 180 miles of large transmission mains for a total asset inventory of 1,305 miles of pipe with over fifty pressure zones. The service area covers the Salt Lake City corporate boundaries as well as the east side of the Salt Lake Valley to the mouth of Little Cottonwood Canyon—a total of 134 square miles. This includes water supply to the newly incorporated Mill Creek City, as well as Cottonwood Heights, Holladay, and small portions of Murray, Midvale, and South Salt Lake Cities. The Department's asset management program includes personnel and systems to assess the condition of the large water transmission mains, treatment and pumping plants, and other infrastructure to assure repair and replacement is completed with minimal impact to the public. Each of the Department's three water treatment plants were originally constructed in the 1950's and have undergone numerous upgrades. There is also a continual need to repair and replace pipe segments to maintain service and reduce emergency repair costs and impacts to the public.

Water Utility Budget Highlights for FY2020

Anticipated Revenues

A proposed 5% rate increase is anticipated to generate an additional $2,442,107. Proposed rates for FY2020 are impacted by two elements: 1) implementation of a rate structure and cost of service study that was finalized in October 2018 and 2) the proposed rate increase. The additional revenue is required for the water utility to meet its capital and operations objectives.

The Department plans to issue bonds during FY2020 with $35,196,000 designated for water. Additional bonding of $112,627,000 is anticipated from FY 2021 to FY2024 meet water utility capital project objectives.

The revenue budget is proposed to increase by $7,026,186 or 5.72% from the FY2019 budget. The proposed budget for FY2020 by major category is as follows:

Projected Water Revenues for FY 2019-20

Revenue	Adopted Budget 2018-2019	Amended Budget 2018-2019	Proposed Budget 2019-2020	Difference	Percent Change
Operating Sales	73,289,346	73,289,346	75,731,453	2,442,107	3.33%
Interest	375,000	375,000	229,000	(146,000)	-38.93%
Interfund Charges	2,449,985	2,449,985	2,475,157	25,172	1.03%
Other Revenues	638,000	638,000	638,000	-	0.00%
Impact Fees	500,000	500,000	1,000,000	500,000	100.00%
Contributions	1,205,000	1,205,000	1,205,000	-	0.00%
Bond Proceeds	-	-	35,196,000	35,196,000	
From (To) Reserves	25,735,446	44,337,800	13,346,707	(30,991,093)	-69.90%
Total	**$ 104,192,777**	**$ 122,795,131**	**$ 129,821,317**	**$ 7,026,186**	**5.72%**

Operating Sales: The implementation of the new rate structure combined with the 5% proposed rate increase is estimated to generate $2,442,107 or 3.33% more than the FY2019 budgeted amount. The implementation of both has no impact on the monthly billing for residential usage of 21 CCF

Interest Income: Interest earnings are expected to decrease as reserve funds are invested in capital improvements.

Interfund Charges: The Water Utility is reimbursed by Sewer, Stormwater, Street Lighting, Refuse, and the Hive program for services related to billing. Related revenue is not expected to change significantly.

Impact Fees: Impact fees are budgeted to increase $500,000 for new development. The FY2020 budget is a conservative estimate based on the historical average.

Bond Proceeds: A bond issue of $35,196,000 million is anticipated.

Reserve Funds: The Department plans to use $13,346,707 of reserve funds to balance the capital and operational needs. Budgeted use of reserve funds is <$30,991,093> less than the FY2019 amended budget or a decrease of <69.90%>.

Proposed Expenditures

The Water Utility's FY2020 budget includes a decrease of <$1,182,293> in other professional and technical services which is off-set by a $1,317,556 increase in personal services. The increase in personal services is attributed to the addition of 7.80 FTEs, a 3% COLA for employees, and a 7% increase in health insurance costs. The new FTEs requested will support the Department's water quality, engineering, water operations, and administration service offerings to benefit residents of the Water Utility's water service area.

The Department expects a $479,845 or 3% increase in the price of water from Metropolitan District of Salt Lake and Sandy for FY2020.

The Department plans to invest $59,255,100 in capital improvements for Water Utility infrastructure in FY2020. The capital improvement program includes a prioritized balance of needed improvements to treatment plants, water lines, meter replacements, pump stations, wells, and other infrastructure.

The schedule for some water main replacements has been accelerated to perform work in conjunction with the General Fund bonded street repair projects. The FY 2020 capital improvements budget includes $9,650,000 for these replacements. Future years anticipate an additional $17,890,000 in projects related to the proposed street related projects that are part of the 2018 general obligation bond for streets. The water main budget also includes the $10,000,000 for the East West Conveyance Line.

The expenditure budget for the Water Utility is proposed to increase $7,026,186 or 5.72% from the FY2019 budget. The proposed budget for FY2020 by major category is as follows:

Proposed Water Expenditures for FY 2019-20

Major Expenditure Categories	Adopted Budget 2018-2019	Amended Budget 2018-2019	Proposed Budget 2019-2020	Difference	Percent Change
Personal Services	22,069,746	22,069,746	23,387,302	1,317,556	5.97%
Materials and Supplies	4,218,280	4,233,777	4,415,380	181,603	4.29%
Charges for Services	36,600,851	39,051,011	38,473,088	(577,923)	-1.48%
Debt Service	1,117,000	1,117,000	1,781,000	664,000	59.44%
Capital Outlay	4,614,400	4,682,304	2,509,447	(2,172,857)	-46.41%
Capital Improvements	35,572,500	51,641,293	59,255,100	7,613,807	14.74%
Total	**$ 104,192,777**	**$ 122,795,131**	**$ 129,821,317**	**$ 7,026,186**	**5.72%**

Personal Services: Employee related costs are estimated to increase $1,317,556 or 5.97%. The water utility budget anticipates an increase of 7.80 FTEs. The FY2020 budget includes a 3% COLA and a 7% increase in costs of health insurance.

Materials & Supplies: The increase of $181,603 is driven by a $110,000 increase in sand and gravel as well as increases in grounds and building supplies and computer supplies. Small tools and equipment decreased from last year.

Charges for Services: The proposed budget for charges and services will decrease <$577,923> or <1.63%>. The decrease can be attributed to a <$1,182,293>decrease in outsourced technical services and a <$111,000> decrease in payment in lieu of taxes that are offset by the price increase for water purchases from Metropolitan Water District.

Debt Service: - In compliance with the Series 2017 Refunding Bond, and in anticipation of a Series 2020—3.9%, 30 Year—Bond, the budget for debt service increased by $664,000.

Capital Outlay: The proposed budget for capital outlay for FY2020 includes $1,500,000 for watershed purchases, $30,000 for water rights, $494,265 for 14 vehicles, $175,182 for field equipment, $50,000 for pumping equipment, $60,000 for treatment plant equipment, $50,000 for telemetry, $30,000 for office furniture & equipment, and $120,000 for other non-motive equipment.

Capital Improvements: The Water proposed CIP budget for FY2020 is $59,255,100. A detailed list of CIP projects is included in the cash flow summaries for the Water Utility. A capital project summary by facility type is as follows:

Proposed Water Capital Improvement Program for FY 2019-20

Type of Project	Proposed Budget 2019-2020
Treatment Plants	7,850,000
Water Service Connections	5,900,000
Pumping Plant Upgrades	1,565,000
Reservoirs	3,435,000
Water Mains and Hydrants	35,530,100
Wells	3,400,000
Culverts, Flumes, and Bridges	1,455,000
Watershed	120,000
Total 2019-2020 CIP	**$ 59,255,100**

Sewer Utility Enterprise Fund

Sewer Infrastructure Background

The City's Water Reclamation Facility (WRF) was constructed in 1965 and has undergone numerous upgrades since. Nutrient removal regulations adopted by the Utah Department of Environmental Quality (UDEQ) in 2015 require a new sewage treatment process. After much study, the Department determined that the WRF has reached the end of its useful life and adapting the 54 year old facility to meet the new nutrient removal requirements is not feasible. A new WRF is currently under design, to be completed by 2024 in order to meet UDEQ's nutrient compliance date of January 1, 2025. The Department has been implementing gradual rate increases and revenue bonding for the replacement of the WRF.

The sewer collection system (654 miles of pipeline, and several pump stations in 2018) is a very challenging environment; hydrogen sulfide gases, sediment, roots and other factors affect the competency of the collection lines. The Department's asset management program includes personnel and systems to assess the condition of the large water transmission mains, treatment and pumping plants, and other infrastructure to assure repair and replacement is completed with minimal impact to the public. More than 50% of the sewer collection system is greater than 85 years old.

The Department is expanding portions of the sewer collection system, in large part to meet growth requirements related to the new State Correctional Facility, the Airport expansion, and new development anticipated in the Northwest Quadrant of Salt Lake City.

Sewer Utility Budget Highlights for FY2020

Total project costs for the WRF reconstruction are anticipated to be $528,130,000 when the project is completed. Construction will begin in FY2020. Public Utilities has expended approximately $6 million over the last several years in preparation for this project.

Current financing for the new WRF is anticipated to be accomplished using a combination of revenue bonds and user rates. The Department plans to submit a letter of interest in spring 2019 for consideration to apply for federal loans pursuant to the Water Infrastructure Finance and Innovation Act (WIFIA). If invited to apply, the program loan would provide up to 49% of the cost of the new WRF. The interest rate is locked in at loan closing and repayment schedules can be structured to complement revenue bond debt payments. If a loan is not approved, the project costs will be funded through revenue bonds. The two scenarios are as follows:

Scenario 1: Sewer Planned Debt

FY	WIFIA	Bonds	Total
2019-2020	-	55,000,000	55,000,000
2020-2021	67,429,000	51,450,000	118,879,000
2021-2022	85,926,000	59,180,000	145,106,000
2022-2023	65,057,000	62,230,000	127,287,000
2023-2024	31,865,000	27,440,000	59,305,000
Total	**$ 250,277,000**	**$ 255,300,000**	**$ 505,577,000**

Scenario 2: Sewer Planned Debt

FY	Bonds
2019-2020	55,000,000
2020-2021	107,000,000
2021-2022	187,000,000
2022-2023	138,000,000
2023-2024	69,000,000
Total	**$ 556,000,000**

Anticipated Revenues

A proposed 18% rate increase is anticipated to generate an additional $6,782,334 in sewer fees. Proposed rates for FY2020 are impacted by two elements: 1) implementation of a rate and cost of service study that was finalized in October 2018; and 2) the proposed rate increase. The additional revenue is required for the Sewer Utility to meet its capital and operations objectives. Rate increases in future years are also anticipated at this time. The rate increases are anticipated to vary based on the source of debt.

Forecast Rate Increases

FY	WIFIA/Bonds	Bonds	Difference
2019-2020	18%	18%	0%
2020-2021	18%	20%	-2%
2021-2022	18%	25%	-7%
2022-2023	15%	25%	-10%
2023-2024	10%	10%	0%
Average	**16%**	**20%**	**-4%**

The Department plans to issue bonds during FY2020 with $55,307,000 designated for the Sewer Utility. Additional debt of $471,287,000 is anticipated from FY2021 to FY2024 to meet Sewer Utility capital objectives, primarily the reconstruction of the WRF. Debt will be used in conjunction with rate increases to blend pay as you go and borrowing strategies. The proposed debt is for a 30 year term creating intergenerational equity payback on the new WRF facility. The process will engage the City's professional advisors to measure debt service and ratios to comply with external rating agency standards. The Department intends to maintain its AAA rating to limit costs of borrowing.

The total revenue budget is expected to decrease by <$6,540,494> or <4.42%> to $141,544,664 from the FY2019 amended budget. A reduction in the budgeted use of reserve funds is driving the decrease. The proposed budget for FY2020 by major category is as follows:

Projected Sewer Revenues for FY 2019-20

Revenue	Adopted Budget 2018-2019	Amended Budget 2018-2019	Proposed Budget 2019-2020	Difference	Percent Change
Operating Sales	37,677,666	37,677,666	44,460,000	6,782,334	18.00%
Interest	1,052,000	1,052,000	604,000	(448,000)	-42.59%
Permits	70,000	70,000	70,000	-	
Other Revenues	185,000	185,000	185,000	-	0.00%
Bond/ Note Proceeds	4,000,000	4,000,000	55,307,000	51,307,000	1282.68%
Impact Fees	700,000	700,000	700,000	-	0.00%
Contribution	2,020,000	2,020,000	2,020,000	-	
From (To) Reserves	65,246,893	102,380,492	38,198,664	(64,181,828)	-62.69%
Total	**$ 110,951,559**	**$ 148,085,158**	**$ 141,544,664**	**$ (6,540,494)**	**-4.42%**

Sewer service fees: Sewer service fees are expected to increase $6,782,334 or 18%. The proposed rate increase is approximately $5.04 per month for the representative resident (assuming winter water use of eight CCF). The increase reflects the implementation of the new rate structure and the 18% rate increase. The additional revenue is required for the sewer utility to meet its capital and operations objectives

Interest Income: Interest earnings are expected to decrease as reserve funds and remaining bond proceeds are invested in capital improvements.

Bond / Note Proceeds: A bond issue of $55,307,000 is anticipated.

Reserve Funds: Reserve funds of $38,198,664, including funds from the 2017 Bond issue, will balance the Sewer Utility's capital and operational needs with FY2020 revenue. Budgeted use of reserve funds decreases <$64,181,828> from the FY2019 budget.

Proposed Expenditures

The proposed sewer budget for FY2020 includes $98,370,500 in planned projects. Of this amount $54,700,000 is planned for the new WRF facility, $6,380,000 for the existing plant, and $36,630,500 for improvements to the sewer collections system. The schedule for some sewer collection line replacements has been accelerated to perform work in conjunction

with the City's general obligation bonded street repair projects. The FY2020 capital improvements budget includes $4,850,000 for these replacements. Future years anticipate an additional $21,200,000 to support the general obligation of the bonded street related projects.

The Sewer Utility's FY 2020 budget proposes a decrease of <$6,540,494> or <4.42%> from the FY2019 amended budget. The proposed budget for FY2020 by major category is as follows:

Proposed Sewer Expenditures for FY 2019-20

Major Expenditure Categories	Adopted Budget 2018-2019	Amended Budget 2018-2019	Proposed Budget 2019-2020	Difference	Percent Change
Personal Services	10,375,345	10,375,345	11,164,232	788,887	7.60%
Materials and Supplies	1,934,720	1,934,720	2,109,430	174,710	9.03%
Charges for Services	6,211,994	7,115,552	7,750,502	634,950	8.92%
Debt Service	6,073,000	6,073,000	13,456,000	7,383,000	121.57%
Capital Outlay	5,946,500	5,946,500	8,694,000	2,747,500	46.20%
Capital Improvements	80,410,000	116,640,041	98,370,500	(18,269,541)	-15.66%
Total	**$ 110,951,559**	**$ 148,085,158**	**$ 141,544,664**	**$ (6,540,494)**	**-4.42%**

<u>Personal Services</u>: Employee related costs are estimated to increase $788,887 or 7.60%. The sewer utility budget anticipates an increase of 6.30 FTEs. The FY2020 budget includes a 3% COLA and a 7% increase in costs of health insurance.

<u>Materials & Supplies</u>: The Sewer Utility's budget for this category increased by $174,710. This increase is attributed to laboratory supplies, chemicals, and small tools and equipment:

<u>Charges for Services</u>: The budget for charges and services increased by $634,950. The most significant items in this category are an increase in data processing services of $113,000 and a $293,013 increase in payment in lieu of taxes.

<u>Debt Service</u>: - The annual debt service budget is expected to increase by $7,383,000 in FY2020. A payment of $6,375,000 on a note payable is required during the year. The remaining increase is in accordance with existing debt service schedules and planned bond issues.

<u>Capital Outlay:</u> - The proposed capital outlay budget for FY2020 includes $5,600,000 for land, $1,717,500 for a vehicles and trucks, $408,000 for field maintenance equipment, $778,500 treatment plant equipment, $10,000 for telemetry, $20,000 for office furniture and equipment, and $160,000 for other non-motive equipment.

Capital Improvements: The Sewer proposed CIP budget for FY2020 is $98,370,500, a decrease of <$18,269,541> from the current year amended budget. A detailed list of capital improvement projects is included in the cash flow summary for the Sewer Utility. A capital project summary by facility type is as follows:

Proposed Sewer Capital Improvement Program for FY 2019-20

Type of Project	Proposed Budget 2019-2020
WRF	61,080,000
Collection System	36,630,500
Lift Stations	510,000
Northwest Oil Drain	150,000
Total 2019-2020 CIP	**$ 98,370,500**

Stormwater Utility Enterprise Fund

Stormwater Infrastructure Background

The Drainage Master Plan was completed in 1993. The FY2020 budget includes an update of the Drainage Master Plan to address water quality and climate change issues, such as storm intensification. The projects identified in the Master Plan provide direction and areas that may or have already been completed. In the last ten years 34.4 miles of storm drain pipe has been installed.

Stormwater Utility Budget Highlights for FY2020

Anticipated Revenues

A proposed 10% rate increase or approximately $0.49 per equivalent residential unit (ERU) per month is included in the budget. Dwindling cash reserves, stronger regulatory requirements and infrastructure needs are drivers for the proposed rate increase. Additional rate increases between 10% and 6% are projected through FY2023.

The Department plans to issue bonds during FY2020 with $14,581,000 designated for stormwater utility needs. Additional bonding is planned in FY 2022.

The revenue budget is proposed to increase by $6,228,860 or 39.62% from the FY2019 budget. The proposed revenue budget for FY2020 by major category is as follows:

Projected Storm Revenues for FY 2019-20

Revenue	Adopted Budget 2018-2019	Amended Budget 2018-2019	Proposed Budget 2019-2020	Difference	Percent Change
Operating Sales	8,855,000	8,855,000	9,740,500	885,500	10.00%
Interest	33,000	33,000	20,820	(12,180)	-36.91%
Other Revenues	200,000	200,000	200,000	-	0.00%
Impact Fees	650,000	650,000	516,000	(134,000)	-20.62%
Contributions	1,000	1,000	1,000	-	0.00%
Bond Proceeds	1,355,000	1,355,000	14,581,000	13,226,000	
From (To) Reserves	2,492,300	4,627,657	(3,108,803)	(7,736,460)	-167.18%
Total	**$ 13,586,300**	**$ 15,721,657**	**$ 21,950,517**	**$ 6,228,860**	39.62%

Operating Sales: A rate increase of 10% or about $0.49 per ERU per month is estimated to generate $885,500 more than the current budget.

Interest Income: Interest earnings are expected to decrease as reserve funds are invested in capital improvements.

Contributions by Developers: Decrease of <$134,000> related to reimbursed cost sharing from oil companies related to Northwest Oil Drain remediation.

Bond / Note Proceeds: A bond issue of $14,581,000 is anticipated.

Reserve Funds: Unspent bond proceeds of $3,108,803 will be added to reserves for use on stormwater system improvements

Proposed Expenditures

The Stormwater Utility's FY2020 budget proposes capitalizing $12,744,000 to renovate portions of the stormwater collection system. The schedule for stormwater system improvements has been accelerated to perform work in conjunction with the general obligation bonded street repair projects. The FY2020 capital improvements budget includes $3,550,000 for these. Future years anticipate an additional $14,725,000 in the bonded street related projects. These capital items will be funded through rate increases and revenue bonds.

The expenditure budget for the Stormwater Utility is proposed to increase $6,228,860 or 39.62% from the current year FY2019 budget. The proposed budget for fiscal year FY2020 by major category is as follows:

Proposed Storm Expenditures for FY 2019-20

Major Expenditure Categories	Adopted Budget 2018-2019	Amended Budget 2018-2019	Proposed Budget 2019-2020	Difference	Percent Change
Personal Services	2,872,608	2,872,608	3,187,954	315,346	10.98%
Materials and Supplies	186,450	186,450	200,950	14,500	7.78%
Charges for Services	3,854,174	4,600,262	3,783,464	(816,798)	-17.76%
Debt Service	1,024,000	1,024,000	1,306,000	282,000	27.54%
Capital Outlay	515,568	515,568	728,149	212,581	41.23%
Capital Improvements	5,133,500	6,522,769	12,744,000	6,221,231	95.38%
Total	**$ 13,586,300**	**$ 15,721,657**	**$ 21,950,517**	**$ 6,228,860**	**39.62%**

Personal Services: Employee related costs are estimated to increase $315,346 or 10.98%. The stormwater utility budget anticipates an increase of 1.90 FTEs. The FY2020 budget includes a 3% COLA and a 7% increase in costs of health insurance.

Charges for Services: The decrease in this category is driven by planned reductions of <$836,222> in professional and consulting services. This decrease is partially offset by an increase in planned data processing costs.

Debt Service: The budget increases by $282,000 or 27.54% in anticipation of a Series 2020—3.9%, 30 Year—Bond.

Capital Outlay: The proposed capital outlay budget for FY2020 includes $672,649 for vehicles and $56,000 for various categories of equipment.

Capital Improvements: The Stormwater proposed capital improvement budget for FY2020 is $12,744,000, an increase of $6,221,231 over the FY2019 budget. A detailed list of

capital improvement projects is provided in the cash flow summary for the Stormwater Utility. The capital project summary by facility types are as follows:

Proposed Storm Capital Improvement Program for FY 2019-20

Type of Project	Proposed Budget 2019-2020
Lines and Riparian Corridor Projects	12,530,000
Lift Stations	64,000
Northwest Oil Drain	150,000
Total 2019-2020 CIP	**$ 12,744,000**

Street Lighting Utility Enterprise Fund

Street Lighting Infrastructure Background

The responsibility for provision of street lighting throughout the city was transferred to the Department from the General Fund in 2013. The Department is currently updating the City's 2006 Street Lighting Master Plan in order to focus on community safety and aesthetic needs, particularly since updating lights and conversion of street lights to energy efficiency bulbs has changed the character of lighting in some neighborhoods.

Of the 15,662 lights that the City maintains, 8,398 lights or 54% are now considered to be energy efficient. We are in the seventh year of a ten-year plan to convert all the lights to high energy efficiency lamps. The FY2020 budget funds continuing conversion to high efficiency lights. Ongoing conversions are anticipated in some neighborhoods once the Street Lighting Master Plan is completed to provide better guidelines related to lighting color and intensity. The Street Lighting Utility is saving energy that has approximately $300,000 favorable effect on the FY2020 budget and a similar effect in future years. There have been and may still be energy saving rebates available as the conversion continues.

Street Lighting Utility Budget Highlights for FY2020

Anticipated Revenues

No rate changes are proposed in the FY2020 budget or forecast in the immediate future. The base lighting rates were established in 2013 at $3.73 per month for an average residential customer, or Equivalent Residential Unit (ERU), and are expected to remain unchanged for this fiscal year. Rates for enhanced tiers are Tier 1 $5.67, Tier 2 $15.94, and Tier 3 $43.82.

Continuation of the private lights program is proposed in the FY2020 budget. The program includes a $20,000 transfer from the General Fund and indicates the on-going desire of the City to provide a matching support to reduce the capital costs to neighborhoods installing private street lighting. Public Utilities administers this program.

The revenue budget is proposed to decrease by <$875,078> from the FY2019 budget. The proposed budget for FY2020 by major category is as follows:

Projected Street Revenues for FY 2019-20

Revenue	Adopted Budget 2018-2019	Amended Budget 2018-2019	Proposed Budget 2019-2020	Difference	Percent Change
Operating Sales	4,170,000	4,170,000	4,198,227	28,227	0.68%
Interest	52,000	52,000	30,000	(22,000)	-42.31%
Other Revenues	9,000	9,000	9,000	-	0.00%
General Fund Contributions	20,000	20,000	20,000	-	0.00%
From (To) Reserves	1,317,117	1,415,355	534,050	(881,305)	-62.27%
Total	**$ 5,568,117**	**$ 5,666,355**	**$ 4,791,277**	**$ (875,078)**	**-15.44%**

Operating Sales: Rate changes are not proposed thus this category is not expected to change significantly. The FY2020 budget is based on actual revenue sales from FY2018

Interest Income: Interest earnings are expected to decrease as reserve funds are utilized.

General Fund Contributions: No change. Public Utilities anticipates the general fund to continue contributing $20,000 for private light options in FY2020.

Reserve Funds: The FY2020 budget anticipates using $534,050 from the utility's reserve funds—mostly unspent bond proceeds from the 2017 bond issue.

Proposed Expenditures

Street Lighting capital improvements totaling $1,725,000 are planned in the FY2020 budget. The Street Lighting Capital Program focuses on high efficiency and system

upgrades in neighborhood, arterial and collector streets and includes $200,000 for lighting controls

The expenditure budget for the Street Lighting Utility is proposed to decrease <$875,078> or <15.44%> from the FY2019 amended budget. The proposed budget for FY2020 by major category is as follows:

Proposed Street Expenditures for FY 2019-20

Major Expenditure Categories	Adopted Budget 2018-2019	Amended Budget 2018-2019	Proposed Budget 2019-2020	Difference	Percent Change
Personal Services	198,307	198,307	281,575	83,268	41.99%
Materials and Supplies	7,300	7,300	7,300	-	0.00%
Charges for Services	2,654,510	2,736,334	2,674,402	(61,932)	-2.26%
Debt Service	103,000	103,000	103,000	-	0.00%
Capital Improvements	2,605,000	2,621,414	1,725,000	(896,414)	-34.20%
Total	**$ 5,568,117**	**$ 5,666,355**	**$ 4,791,277**	**$ (875,078)**	**-15.44%**

Personal Services: Employee related costs are estimated to increase $83,268 of 41.99%. The Street Lighting Utility budget anticipates an increase of 1 FTE. The FY2020 budget includes a 3% COLA and a 7% increase in costs of employee insurance premiums.

Charges for Services: The proposed budget for charges and services decreases <$61,932> or <2.26%> in FY2020 with a <$81,824> budgeted decrease in professional services off-set by an increase in budgeted power costs.

Debt Service: In compliance with the outstanding bond, Series 2017 Bond, budgeted debt service payments remain unchanged in FY2020.

Capital Equipment: No expenditures for capital equipment are planned.

Capital Improvements: The proposed Street Lighting CIP budget for FY2020 is $1,725,0000, a decrease of <$896,414> from the FY2019 amended budget. A capital projects summary by facility type is as follows for base lighting and all enhanced tiers:

Proposed Street Capital Improvement Program for FY 2019-20

Type of Project	Proposed Budget 2019-2020
System upgrade for high efficiency and uniformity	1,525,000
Lighting controls	200,000
Total 2019-2020 CIP	**$ 1,725,000.00**

Combined Utilities- Budget Summary and Cash Flow

PUBLIC UTILITIES
WATER, SEWER, STORMWATER, AND STREET LIGHTING ENTERPRISE FUNDS
COMBINED BUDGET SUMMARY
2020-2022 BUDGET

Combined Annual Rate Increase				8.2%	10.0%	10.1%
SOURCES	ACTUAL 2017-2018	AMENDED BUDGET **2018-2019**	PROJECTED ACTUAL **2018-2019**	**PROPOSED BUDGET 2019-2020**	**FORECAST BUDGET 2020-2021**	**FORECAST BUDGET 2021-2022**
REVENUES						
METERED SALES	$111,480,405	$119,822,012	$118,657,859	**$129,931,953**	$143,336,576	158,243,087
INTEREST INCOME	2,630,722	1,512,000	1,512,000	**883,820**	$318,816	185,338
OTHER REVENUES	5,931,175	3,282,985	3,284,985	**3,308,157**	$3,308,157	3,308,157
STREET LIGHTING FEES	4,198,227	4,170,000	4,198,227	**4,198,227**	$4,198,227	4,198,227
TOTAL REVENUES	$124,240,529	$128,786,997	$127,653,071	**$138,322,157**	$151,161,776	165,934,809
OTHER SOURCES						
GRANTS & OTHER RELATED REVENUES	$3,333,556	$3,875,000	$3,875,000	**$3,741,000**	$3,741,000	2,441,000
IMPACT FEES	2,858,059	1,400,000	1,400,000	**1,900,000**	1,924,500	1,949,858
TRANSFERS FROM GENERAL FUND	20,000	20,000	20,000	**20,000**	20,000	20,000
BOND PROCEEDS	0	0	0	**105,084,000**	81,453,000	129,847,200
NON BOND FINANCING	8,500,000	4,000,000	0	**0**	67,429,000	85,926,000
SHORT-TERM FINANCING	0	1,355,000	0	**0**	0	0
COUNTY FLOOD CONTROL	0	0	0	**0**	0	0
OTHER SOURCES	118,152	70,000	70,000	**70,000**	70,000	70,000
T O T A L OTHER SOURCES	$14,829,767	$10,720,000	$5,365,000	**$110,815,000**	$154,637,500	220,254,058
T O T A L SOURCES	$139,070,296	$139,506,997	$133,018,071	**$249,137,157**	$305,799,276	386,188,867
EXPENSES & OTHER USES						
EXPENDITURES						
PERSONNEL SERVICES	$30,935,175	$35,516,006	$35,516,006	**$38,021,063**	$39,541,905	41,123,577
OPERATING & MAINTENANCE	$4,951,624	6,362,247	$6,362,247	**$6,733,060**	6,856,022	6,993,143
TRAVEL & TRAINING	$101,729	249,058	$249,058	**304,773**	310,870	317,086
UTILITIES	$4,289,708	5,069,662	$5,069,662	**5,034,877**	5,074,877	5,123,765
TECHNICAL SERVICES	$7,156,710	15,878,757	$15,878,757	**13,638,603**	12,572,550	12,529,406
DATA PROCESSING	$1,765,209	1,487,047	$1,487,047	**1,876,347**	1,913,875	1,952,151
PUBLIC SERVICES / STREET SWEEPING	$819,605	819,605	$819,605	**819,605**	835,997	852,717
FLEET MAINTENANCE	1,821,898	2,007,000	$2,007,000	**2,007,000**	2,047,140	2,088,082
ADMINISTRATIVE SERVICE FEE	1,089,863	1,225,000	$1,225,000	**1,251,000**	1,276,020	1,301,540
PAYMENT IN LIEU OF TAXES	814,795	970,192	$970,192	**1,126,697**	1,149,231	1,172,216
RISK MANAGEMENT	1,313,881	1,484,033	$1,484,033	**1,468,353**	1,497,720	1,527,673
TRANSFERS TO GENERAL FUND	0	109,000	$109,000	**89,000**	90,780	92,596
BILLING COST	1,237,745	1,368,013	$1,368,013	**1,373,051**	1,400,512	1,428,523
BONDING NOTE EXPENSE	0	0	$0	**-**	-	-
METRO. WATER PURCH & TREAT	15,528,950	15,994,818	$15,994,818	**16,474,663**	16,968,903	17,477,971
METRO ASSESSMENT (CAPITAL)	7,021,892	7,021,892	$7,021,892	**7,021,892**	7,021,892	7,021,892
OTHER CHARGES AND SERVICES	(869,406)	(180,918)	($180,918)	**195,595**	198,370	202,338
TOTAL EXPENDITURES	$77,979,378	$95,381,412	$95,381,412	**$97,435,579**	$98,756,664	101,204,676
OTHER USES						
CAPITAL OUTLAY	$6,193,492	$11,144,372	$6,716,975	**$11,931,596**	$4,373,000	4,373,000
CAPITAL IMPROVEMENT BUDGET	55,576,281	177,425,517	91,909,315	**172,094,600**	189,219,500	255,098,400
COST OF DEBT ISSUANCE	9,100	25,000	0	**584,000**	453,000	722,200
DEBT SERVICES	7,645,659	8,292,000	8,284,603	**16,062,000**	18,282,000	20,218,000
T O T A L OTHER USES	$69,424,532	$196,886,889	$106,910,893	**$200,672,196**	$212,327,500	280,411,600
T O T A L USES	$147,403,910	$292,268,301	$202,292,305	**$298,107,775**	$311,084,164	381,616,276
EXCESS REVENUE AND OTHER SOURCES OVER (UNDER) USES	($8,333,614)	($152,761,304)	($69,274,234)	**($48,970,618)**	($5,284,888)	4,572,591
OPERATING CASH BALANCES						
BEGINNING JULY 1	$152,753,095	$144,419,481	$144,419,481	**$75,145,247**	$26,174,629	20,889,741
ENDING JUNE 30	$144,419,481	($8,341,823)	$75,145,247	**$26,174,629**	$20,889,741	25,462,332
Cash Reserve Ratio	185%	-9%	79%	**27%**	21%	25%

Cash reserve goal above 10%

PUBLIC UTILITIES
Water, Sewer, Stormwater and Street Lighting Enterprise Funds
Combined Cash Flow
FY 2020 Budget and FY 2021-2024 Forecast Budget

	ACTUAL YEAR 2017-2018	PROJECTED YEAR 2018-2019	BUDGET YEAR 2019-2020	BUDGET YEAR 2020-2021	BUDGET YEAR 2021-2022	BUDGET YEAR 2022-2023	BUDGET YEAR 2023-2024
WATER SALES	69,351,147	72,125,193	75,731,453	79,784,026	83,773,227	87,961,888	93,239,601
SEWER CHARGES	33,620,751	37,677,666	44,460,000	52,838,000	62,791,000	72,718,000	80,548,000
STORMWATER FEES	8,508,507	8,855,000	9,740,500	10,714,550	11,678,860	12,379,591	12,998,571
STREET LIGHTING FEES	4,198,227	4,198,227	4,198,227	4,198,227	4,198,227	4,198,227	4,198,227
TOTAL SERVICES FEES AND CHARGES	115,678,632	122,856,086	134,130,180	147,534,803	162,441,314	177,257,706	190,984,399
OTHER INCOME	5,934,020	3,304,985	3,328,157	3,328,157	3,328,157	3,328,157	3,328,157
INTEREST INCOME	2,630,722	1,512,000	883,820	318,816	185,338	256,254	203,104
OPERATING INCOME	124,243,374	127,673,071	138,342,157	151,181,776	165,954,809	180,842,117	194,515,660
OPERATING EXPENDITURES	(77,986,578)	(95,381,412)	(97,435,579)	(98,756,664)	(101,204,676)	(103,806,581)	(106,203,662)
NET INCOME EXCLUDING DEP.	46,256,796	32,291,659	40,906,578	52,425,112	64,750,133	77,035,536	88,311,998
WIFIA LOAN			0	67429000	85926000	65057000	31865000
NET BOND PROCEEDS	0	0	104,500,000	81,000,000	129,125,000	94,000,000	42,000,000
SHORT TERM FINANCING	0	0	0	0	0	0	0
STATE LOAN	8,500,000	0	0	0	0	0	0
IMPACT FEES	2,858,059	1,400,000	1,900,000	1,924,500	1,949,858	1,976,103	2,003,267
OTHER CONTRIBUTIONS	3,468,863	3,945,000	3,811,000	3,811,000	2,511,000	2,311,000	2,311,000
CAPITAL OUTLAY	(6,193,492)	(6,126,238)	(10,431,596)	(2,873,000)	(2,873,000)	(2,873,000)	(2,873,000)
WATERSHED PURCHASES	0	(590,737)	(1,500,000)	(1,500,000)	(1,500,000)	(1,500,000)	(1,500,000)
STATE LOAND DEBT SERVICE	0	0	(6,375,000)	(2,125,000)	0	0	0
SHORT TERM FINANCING DEBT SERVICE	0	0	0	0	0	0	0
DEBT SERVICE	(7,647,559)	(8,284,603)	(8,297,000)	(10,861,000)	(10,854,000)	(10,851,000)	(11,183,850)
NEW DEBT SERVICE	0	0	(1,390,000)	(5,296,000)	(9,364,000)	(14,459,000)	(20,281,000)
OTHER INCOME & EXPENSE	985,871	(9,656,578)	82,217,404	131,509,500	194,920,858	133,661,103	42,341,417
AVAILABLE FOR CAPITAL	47,242,667	22,635,081	123,123,982	183,934,612	259,670,991	210,696,639	130,653,415
CAPITAL IMPROVEMENTS	(55,576,281)	(91,909,315)	(172,094,600)	(189,219,500)	(255,098,400)	(214,028,000)	(130,399,000)
BEGINING CASH BALANCE	152,753,095	144,419,481	75,145,247	26,174,629	20,889,741	25,462,332	21,880,971
CASH INCREASE/(DECREASE)	(8,333,614)	(69,274,234)	(48,970,618)	(5,284,888)	4,572,591	(3,331,361)	254,415
ENDING BALANCES	144,419,481	75,145,247	26,174,629	20,889,741	25,462,332	22,130,971	22,135,386
DEBT SERVICE COVERAGE	6.05	3.90	4.22	3.24	3.20	3.04	2.81
CASH RESERVE RATIO	185.2%	78.8%	26.9%	21.2%	25.2%	21.3%	20.8%
DEBT SERVICE % OF GROSS OPERATING REVENUE	6.3%	6.5%	6.9%	10.5%	12.1%	13.9%	16.1%
RESIDENTIAL UTILITY BILL	63.65	67.46	70.25	75.76	81.86	87.88	93.81
% CHANGE RESIDENTIAL UTILITY BILL*		6.0%	4.14%	7.8%	8.1%	7.4%	6.7%

*** Residential Utility Bill assumes annual water consumption of 255 ccf/12 months, 4 ccf monthly of sewer, 1 Stormwater ERU (.25 acres) monthly, and 1 Street Lighting ERU (75 feet) monthly.**

PUBLIC UTILITIES
FEES AND CHARGES PAID TO THE GENERAL FUND
FOR SERVICES RENDERED
OR COLLECTED BY CITY ORDINANCE

DESCRIPTION OF SERVICES	June 30, 2018 ACTUALS WATER	June 30, 2018 ACTUALS SEWER	June 30, 2018 ACTUALS STORM	June 30, 2018 ACTUALS STREET LIGHT	ACTUAL Public Utilities June 30, 2018 TOTALS	FY 2018/2019 BUDGET	FY PROPOSED 2019/2020 BUDGET
Administrative Service Fees (General Fund)							
Human Resources	$ 144,501	$ 124,064	$ 33,232	$ 1,954	$ 303,751	$ 358,450	**$ 348,670**
City Attorney	135,198	22,364	10,165	2,033	169,760	167,350	**194,860**
Accounting/Finance	131,822	58,626	12,442	3,569	206,459	272,280	**236,980**
Purchasing & Contracts	66,060	27,842	3,213	2,607	99,722	96,130	**114,470**
City Recorders	45,263	7,259	7,651	867	61,040	86,260	**70,060**
Property Management	-	-	-	-	-	7,770	**-**
Budget and Policy	25,667	10,732	3,041	217	39,657	45,780	**45,520**
Non-discretionary IMS Costs	50,630	27,072	13,881	1,094	92,677	197,480	**106,380**
Treasurer's Office (cash mgt.)	11,272	4,585	3,974	2,952	22,783	13,970	**26,150**
City Council	37,787	22,758	13,311	16,746	90,602	50,960	**104,000**
Mayor	326	326	326	-	978	3,070	**1,120**
Community Affairs	1,012	632	379	411	2,434	1,000	**2,790**
Total Admin Fees	$ 649,538	$ 306,260	$ 101,615	$ 32,450	$ 1,089,863	$ 1,300,500	**$ 1,251,000**
Tax or Fee Authorized							**-**
Payment in Lieu-of-Taxes (General Fund)	$ 398,485	$ 306,525	$ 109,785	$ -	$ 814,795	$ 831,092	**1,126,697**
Franchise Fees (General Fund)	2,810,068	1,374,769	350,175	-	4,535,012	5,622,628	**6,147,049**
Sub Total	$ 3,208,553	$ 1,681,294	$ 459,960	$ -	$ 5,349,807	$ 6,453,720	**$ 7,273,746**
Internal Service Fund Services							
Fleet Mgt. Services	$ 1,029,585	$ 568,448	$ 223,731	$ -	$ 1,821,764	$ 2,042,040	**$ 2,007,000**
City Data Processing (IMS)	912,977	381,234	294,929	1,117	1,590,257	933,300	**1,539,000**
Telephone Charges	-	-	-	-	-	94,248	**8,400**
Risk Mgt. Admininstrative Fees (Gov. Immunity)	111,519	44,317	3,048	-	158,884	246,381	**216,550**
Risk Management Premiums & Charges	632,362	258,886	54,937	-	946,185	1,495,502	**1,251,803**
Sub Total	$ 2,686,442	$ 1,252,885	$ 576,645	$ 1,117	$ 4,517,090	$ 4,811,471	**5,022,753**
Special Associated Charges (indirect benefit)							
OneSolution Maintenance (network financial syste	$ -	$ -	$ -	$ -	$ -	$ 111,180	**89,000**
Street Sweeping	-	-	819,605	-	819,605	835,997	**819,605**
Neighborhood Clean-up	-	-	-	-	-	118,000	**-**
Emergency Management	-	-	-	-	-	30,000	**-**
Tracy Aviary Stormwater Education Cost	-	-	154,350	-	154,350	75,000	**75,000**
Sub Total	$ -	$ -	$ 973,955	$ -	$ 973,955	$ 1,170,177	**$ 983,605**
TOTAL FEES, TAXES AND CHARGES	$ 6,544,533	$ 3,240,440	$ 2,112,175	$ 33,567	$ 11,930,715	$ 13,735,868	**$ 14,531,104**

Public Utilities Proposed Consulting Studies for FY 2019-2020

Division	Cost Center	Study or Project Description	Lighting	Water	Sewer	Storm	Total
Administration	5103000	5-Year Emergency Preparedeness Plan		12,000			12,000
Administration	5100200	Well Study		20,000			20,000
Administration	5103000	Ongoing Environmental Assessments for PU facilities		20,000			20,000
Administration	5103400	Standards development		20,000			20,000
Administration	5103600	Water Conservation		50,000			50,000
Administration	5100200	Central Wasatch Commission		200,000			200,000
Engineering	4848000	Street Light Master Plan	90,000				90,000
Engineering	5210400	Basin Inflow Testing			300,000		300,000
Engineering	5210400	Jacobs Program Support			350,000		350,000
Engineering	5310300	Jacobs Program Support				50,000	50,000
Engineering	5310300	Storm Water Master Plan				700,000	700,000
Engineering	5101300	Water loss study		100,000			100,000
Engineering	5101300	AMP for Storage Reservors		135,000			135,000
Engineering	5101300	Campus study		350,000			350,000
Engineering	5101300	Jacobs Program Support		400,000			400,000
Engineering	5101300	Water Master Plan		500,000			500,000
Finance	5211700	Energy Retro-Commissioning Study			55,000		55,000
Finance	5310500	Energy Retro-Commissioning Study				35,000	35,000
Finance	5103200	Adjudication and other administrative needs.		500,000			500,000
GIS	5101600	Water Data Tracking Software & Consultant		250,000			250,000
Maintenance	5310200	Clean parts of Irrigation system				25,000	25,000
Maintenance	5100100	Geotech consultants		50,000			50,000
Maintenance	5100100	Consulting Project for Canals		60,000			60,000
Maintenance	5100300	Consultants for Well Issues		100,000			100,000
Reclamation	5212400	Study to identify inhibiting-causing pollutants at the WRF			40,000		40,000
Reclamation	5212400	Study to evaluate and determine updated local wastewater discharge limits			60,000		60,000
Reclamation	5212400	Study to evaluate and determine updated sewer rate classifications			250,000		250,000
Water Quality	5310700	Consultant to address MS4 Audit/QAQC				20,000	20,000
Water Quality	5310700	TMDL Load Allocation				50,000	50,000
Water Quality	5100600	Misc Needs		15,000			15,000
Water Quality	5100600	PR Campaign additional Funds		30,000			30,000
Water Quality	5101800	Public Relations		30,000			30,000
Water Quality	5101800	Utah State University Canal Water Quality Analysis		32,000			32,000
Water Quality	5101800	Process Controls		35,000			35,000
Water Quality	5100600	Watershed Plan		120,000			120,000
			$ 90,000	**$ 3,029,000**	**$ 1,055,000**	**$ 880,000**	**$ 5,054,000**

Water Utility- Budget Summary and Cash Flow

WATER UTILITY
ENTERPRISE FUND
BUDGET SUMMARY
Fiscal Years 2020-22

	-			Rate Increase 5%	Rate Increase 5%	Rate Increase 5%
SOURCES	ACTUAL 2017-18	AMENDED BUDGET 2018-19	PROJECTED ACTUAL 2018-19	**PROPOSED BUDGET 2019-20**	**FORECAST BUDGET 2020-21**	**FORECAST BUDGET 2021-22**
REVENUES						
METERED SALES	$69,351,147	$73,289,346	$72,125,193	**$75,731,453**	$79,784,026	$83,773,227
INTEREST INCOME	831,749	375,000	375,000	**229,000**	92,000	89,000
OTHER REVENUES	4,240,466	3,037,985	3,037,985	**3,063,157**	3,063,157	3,063,157
TOTAL REVENUES	$74,423,362	$76,702,331	$75,538,178	**$79,023,610**	$82,939,183	$86,925,384
OTHER SOURCES						
GRANTS & OTHER RELATED REVENUES	$1,804,748	$1,205,000	$1,205,000	**$1,205,000**	$1,205,000	$1,205,000
IMPACT FEES	1,520,259	500,000	500,000	**1,000,000**	1,000,000	1,000,000
OTHER SOURCES	115,307	50,000	50,000	**50,000**	50,000	50,000
BOND PROCEEDS	-	-	-	**35,196,000**	42,235,000	26,146,000
T O T A L OTHER SOURCES	$3,440,314	$1,755,000	$1,755,000	**$37,451,000**	$44,490,000	$28,401,000
T O T A L SOURCES	$77,863,676	$78,457,331	$77,293,178	**$116,474,610**	$127,429,183	$115,326,384
EXPENSES & OTHER USES						
EXPENDITURES						
PERSONNEL SERVICES	$19,852,264	$22,069,746	$22,069,746	**23,387,302**	$24,322,796	$25,295,713
OPERATING & MAINTENANCE	3,392,135	4,233,777	4,233,777	**4,415,380**	4,492,588	4,582,441
TRAVEL & TRAINING	45,173	146,408	146,408	**167,083**	170,426	173,834
UTILITIES	2,397,853	2,854,647	2,854,647	**2,784,962**	2,840,660	2,897,473
TECHNICAL SERVICES	3,657,447	8,726,160	8,726,160	**7,543,867**	6,490,344	6,390,712
DATA PROCESSING	1,065,047	967,347	967,347	**1,177,347**	1,200,895	1,224,911
FLEET MAINTENANCE	1,029,720	1,250,000	1,250,000	**1,250,000**	1,275,000	1,300,500
ADMINISTRATIVE SERVICE FEE	649,538	800,000	800,000	**800,000**	816,000	832,320
PAYMENT IN LIEU OF TAXES	398,485	476,000	476,000	**365,000**	372,300	379,746
METRO. WATER PURCH & TREAT	15,528,950	15,994,818	15,994,818	**16,474,663**	16,968,903	17,477,971
METRO ASSESSMENT (CAPITAL)	7,021,892	7,021,892	7,021,892	**7,021,892**	7,021,892	7,021,892
RISK MANAGEMENT	952,332	1,088,550	1,088,550	**1,123,187**	1,145,651	1,168,563
TRANSFERS TO GENERAL FUND	0	85,000	85,000	**85,000**	86,700	88,434
OTHER CHARGES AND SERVICES	(1,032,212)	(359,811)	(359,811)	**(319,913)**	(328,020)	(334,579)
TOTAL EXPENDITURES	$54,958,624	$65,354,534	$65,354,534	**$66,275,770**	$66,876,135	$68,499,931
OTHER USES						
CAPITAL OUTLAY	$5,148,158	$4,682,304	$4,898,838	**$2,509,447**	$2,930,000	$2,930,000
CAPITAL IMPROVEMENT BUDGET	18,041,425	51,641,293	24,629,211	**59,255,100**	53,501,500	38,542,400
COST OF DEBT ISSUANCE	1,900	0	0	**196,000**	235,000	146,000
DEBT SERVICES	967,961	1,117,000	1,117,000	**1,585,000**	3,043,000	4,600,000
T O T A L OTHER USES	$24,159,444	$57,440,597	$30,645,049	**$63,545,547**	$59,709,500	$46,218,400
T O T A L USES	$79,118,068	$122,795,131	$95,999,583	**$129,821,317**	$126,585,635	$114,718,331
EXCESS REVENUE AND OTHER SOURCES OVER (UNDER) USES	($1,254,392)	($44,337,800)	($18,706,405)	**($13,346,707)**	$843,548	$608,053
OPERATING CASH BALANCES						
BEGINNING JULY 1	$47,048,055	$45,793,663	$45,793,663	**$27,087,258**	$13,740,551	$14,584,099
ENDING JUNE 30	$45,793,663	$1,455,863	$27,087,258	**$13,740,551**	$14,584,099	$15,192,152
Cash Reserve Ratio	83%	2%	41%	**21%**	22%	22%

Cash reserve goal above 10%

WATER UTILITY
Cash Flow
FY 2020 Budget
and FY 2021-2024 Budget Forecast

Rates +5% FY20 - FY23 +6% FY24
Bonds Total $169M, $35M,$42M,$26M,$29M,$15M ...
CIP 100%, New Bond Pmts thru FY 24: $21.3

	ACTUAL YEAR 2017-2018	PROJECTED YEAR 2018-2019	BUDGET YEAR 2019-2020	BUDGET YEAR 2020-2021	BUDGET YEAR 2021-2022	BUDGET YEAR 2022-2023	BUDGET YEAR 2023-2024
WATER SALES	69,351,147	72,125,193	75,731,453	79,784,026	83,773,227	87,961,888	93,239,601
OTHER INCOME	4,240,466	3,037,985	3,063,157	3,063,157	3,063,157	3,063,157	3,063,157
INTEREST INCOME	831,749	375,000	229,000	92,000	89,000	90,000	93,000
OPERATING INCOME	74,423,362	75,538,178	79,023,610	82,939,183	86,925,384	91,115,045	96,395,758
METROPOLITAN WATER ASSESSMENT	(7,021,892)	(7,021,892)	(7,021,892)	(7,021,892)	(7,021,892)	(7,021,892)	(7,021,892)
METROPOLITAN WATER PURCHASES	(15,528,950)	(15,994,819)	(16,474,663)	(16,968,903)	(17,477,971)	(18,002,310)	(18,542,380)
OPERATING EXPENDITURES	(32,407,782)	(42,337,823)	(42,779,215)	(42,885,337)	(44,000,060)	(45,120,974)	(46,539,544)
NET INCOME EXCLUDING DEP.	19,464,738	10,183,644	12,747,840	16,063,051	18,425,461	20,969,869	24,291,942
NET BOND PROCEEDS			35,000,000	42,000,000	26,000,000	29,000,000	15,000,000
BIC Borrowed			196,000	235,000	146,000	162,000	84,000
BIC Paid			(196,000)	(235,000)	(146,000)	(162,000)	(84,000)
SHORT TERM FINANCING							
IMPACT FEES	1,520,259	500,000	1,000,000	1,000,000	1,000,000	1,000,000	1,000,000
OTHER CONTRIBUTIONS	1,920,055	1,255,000	1,255,000	1,255,000	1,255,000	1,255,000	1,255,000
CAPITAL OUTLAY	(5,148,158)	(4,308,101)	(1,009,447)	(1,430,000)	(1,430,000)	(1,430,000)	(1,430,000)
WATERSHED PURCHASES	0	(590,737)	(1,500,000)	(1,500,000)	(1,500,000)	(1,500,000)	(1,500,000)
DEBT SERVICE	(969,861)	(1,117,000)	(1,127,000)	(1,085,000)	(1,090,000)	(1,091,000)	(1,040,000)
NEW DEBT SERVICE	0	0	(458,000)	(1,958,000)	(3,510,000)	(4,730,000)	(6,625,000)
OTHER INCOME & EXPENSE	(2,677,705)	(4,260,838)	33,160,553	38,282,000	20,725,000	22,504,000	6,660,000
GENERATED FOR CAPITAL	16,787,033	5,922,806	45,908,393	54,345,051	39,150,461	43,473,869	30,951,942
CAPITAL IMPROVEMENTS	**(18,041,425)**	**(24,629,211)**	**(59,255,100)**	**(53,501,500)**	**(38,542,400)**	**(42,350,000)**	**(29,914,000)**
BEGINING CASH BALANCE	47,048,055	45,793,663	27,087,258	13,740,551	14,584,102	15,192,163	16,316,032
CASH INCREASE/(DECREASE)	(1,254,392)	(18,706,405)	(13,346,707)	843,551	608,061	1,123,869	1,037,942
ENDING BALANCES	45,793,663	27,087,258	13,740,551	14,584,102	15,192,163	16,316,032	17,353,974
RESTRICTED / RESERVED CASH	(23,928,611)	(8,952,141)	(8,952,141)	(8,952,141)	(8,952,141)	(8,952,141)	(8,952,141)
AVAILABLE ENDING BALANCE	21,865,052	18,135,117	4,788,410	5,631,961	6,240,022	7,363,891	8,401,833
S&P COVERAGE (INCLUDES MWA AS DEBT SERVICE)		**2.11**	2.30	**2**	**2.19**	**2.18**	**2.13**
DEBT SERVICE COVERAGE	**20.07**	**9.12**	**8.04**	**5**	**4.01**	**3.60**	**3.17**
RATE CHANGE	**4%**	**4%**	**5%**	**5%**	**5%**	**5%**	**6%**
Cash Reserve Ratio (Total Cash)	**83%**	**41%**	**21%**	**22%**	**22%**	**23%**	**24%**
DEBT SERVICE % OF GROSS OPERATING REVENUE	1.30%	1.45%	1.95%	3.57%	5.16%	6.23%	7.77%
MONTHLY RESIDENTIAL BILL (255 ccf annually/12 mos.)	44.83	46.60	46.41	48.74	51.18	53.74	56.97

WATER UTILITY CIP BUDGET
Five Year Projected Budget FY2020-2024

COST CENTER	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	CRITICALITY RATING	CONDITION RATING	PAST YEAR SPENT 2018-19 (Calc'd from P6)	BUDGET YEAR 2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
51-01301-	2720.10		**MAINTENANCE & REPAIR SHOPS**									
01401		2015-0460	DISTRIBUTION AND ELECTRICAL BARN	4	4	0						850,000
			CAMPUS	5	5					15,000,000	10,000,000	
03201	512185		FUEL PUMP AWNINGS	5	0	0				250,000		
						$ -	$ -	$ -	$ -	$ 15,250,000	$ 10,000,000	$ 850,000
51-01301-	2720.30		**TREATMENT PLANTS**									
			CITY CREEK									
00701	5122628	2015-0178	DRYING BED PIPELINES	5	5	723,637						
00701	5122665	2015-0685	CCWTP CONTINGENCY PROJECTS	5	5	0						
00701	512260079	2017-2043	TREATMENT PLANT UPGRADES (PENDING 2019 ASSESSMENT RESULTS; DESIGN AND CONST	5	5	326,088	1,500,000	1,500,000	1,500,000	1,500,000	1,500,000	
00701	5122674		HYPOGENERATOR DESIGN	3	0	0						
00701		2015-0177	CITY CREEK - ACTUATORS/SCADA (MULTIPLE LOCATIONS)	3	3	0						
00701		2015-0182	IMPLEMENTATION OF SCADA MASTER PLAN	3	3	0						
00701		2015-0447	CLARIFIER UPGRADE	3	3	0						
00701		2015-0702	ELECTRICAL SYSTEM ASSESSMENT AND UPGRADE	5	4	0						
00701		2016-0871	SEISMIC UPGRADE FILTER BUILDIING STUDY	5	4	0						
00701		2016-0876	PRESSURE DIFFERENTIAL TRANSMITTERS	3	4	0						
00701		2016-0880	CREEK CHANNEL	3	4	0						
00701		2016-0881	FILTER/FLUORIDE BUILDING GATE	3	4	0						
00701		2017-1297	PUMP BACK SYSTEM	2	0	0						
00701		2018-1098	CITY CREEK FILTER MEDIA REPLACEMENT	4	5	0						
00701		2019-1001	CITY CREEK WTP UPGRADES - PHASE 2	5	3	0						30,000,000
00701	512260078	2016-0879	BACKWASH TANK SEISMIC UPGRADE AND RETAINING WALL	5	4	62,473						
00701	512260077	2017-2042	CITY CREEK CCTV SYSTEM UPGRADE	5	4	18,000						
00701	5122676		COAGULATION BUILDING DEMOLITION			101,669						
						$ 1,231,866	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 30,000,000
			PARLEY'S									
00801	5124561	2015-0686	PWTP CONTINGENCY PROJECTS	5	5	0						
00801	512450070	2015-0688	FILTER ASSESSMENT AND FILTER #5 REPAIR	5	5	75,000						
00801	5124525	2015-0203	REPLACE SLUDGE COLLECTION SYSTEM FLIGHTS, CHAINS, AND DRIVES	5	5	1,898,136						
00801	5124506	2015-0201	LABORATORY UPGRADE (BUILD)	5	4	1,284,460						
00801	512450068	2015-0701	PLANT DESIGN AND UPGRADES	5	4	205,880	1,500,000	10,000,000	2,000,000	2,000,000	2,000,000	
00801	5124532		REPLACEMENT OF CHEMICAL FEED PUMPS PARLEY'S CANYON			0						
00801	512450069	2015-0594	BACK-UP WATER SUPPLY FOR HIGH PRESSURE TANK	5	3	0						
00801		2015-0695	RELOCATE POTASSIUM PERMANGANATE FEED SYSTEM	4	4	0						
00801	5124526	2015-0455	INFLUENT CONTROL BOX	4	3	0						
00801	512450066	2016-0867	ROOF REPLACEMENT	4	5	0						
00801	512450067	2016-0874	REBUILD/REPLACE FLOC-SED BASIN VENTILATION SYSTEM	2	5	0						
00801		2015-0450	PRECURSOR - TASTE AND ODOR CONTROL	3	3	0						
00801	5124504	2015-0449	SLUDGE BEDS - PIPING AND VALVES	2	3	0						
00801		2015-0197	ELECTRICAL CONDUITS/PAVING TO BLOW-OFF BOX/ASPHALT EAST AND SOUTH OF FA(	3	3	0						
00801		2015-0204	REPLACE FLOCCULATORS	4	4	0						
00801		2015-0448	SCADA MASTER PLAN IMPLEMENTATION	4	4	0						
00801		2015-0452	NEW I/O AND PLC	2	1	0						
00801		2017-2005	PROCESS UPGRADES (FROM SED BASIN PREDESIGN)	1	0	0						
00801		2017-2006	VERTICAL FLOCCULATOR INSTALLATION	5	3	0						
00801	512450072	2016-1280	PLANT LIGHTING	5	4	30,000						
00801	512450073		SODIUM HYPOCHLORITE STORAGE TANK FOR PWTP AND BCWTP			40,000	300,000					
00801		2018-1037	PARLEYS DIVERSION SCREEN PROJECT	4	0	0	250,000	1,250,000				1,500,000

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00801		2018-1095	PARLEYS FINISHED WATER RESERVOIR	3	0	0						20,000,000
00801		2018-1094	NEW PARLEYS WATER TREATMENT PLANT	5	4	0						136,500,000
						$ 3,533,477	$ 2,050,000	$ 11,250,000	$ 2,000,000	$ 2,000,000	$ 2,000,000	$ 158,000,000
			BIG COTTONWOOD									
00901	51262759	2015-0186	SCADA MASTER PLAN/OPERATOR STATION UPGRADE IMPLEMENTATION			0	300,000					
00901	512627462	2015-0684	BCWTP CONTINGENCY PROJECTS	5	5	0						
00901	512627460	2015-0192	SEDIMENTATION BASIN REBUILD	5	5	829,641						
00901		2019-1002	BIG COTTONWOOD WTP REBUILD - PHASE 1	5	4	0	2,500,000	5,000,000	2,500,000	2,000,000	2,000,000	80,000,000
00901		2015-0191	BIG COTTONWOOD - ASPHALT LOWER-END OF BUILDING TO DRYING BEDS	5	5	0						
00901	512627469	2017-2049	RELOCATION AND HOUSING OF SWITCHGEAR	5	5	0						
00901		2015-0188	FINISHED WATER FLOW METER/FINISHED WATER SAMPLE POINT	5	4	0						
00901		2016-1236	90 FOOT CHANNEL UPGRADES	4	4	0						
00901		2015-0190	REPLACE FLOCCULATION SHAFT DRIVES AND EQUIPMENT	4	4	0						150,000
00901		2015-0698	REROOF COAGULATION BUILDING	4	3	0						100,000
00901		2018-1030	BIG COTTONWOOD SLUDGE SYSTEM UPGRADE	5	4	0						1,500,000
00901		2018-1043	BIG COTTONWOOD WTP REBUILD - PHASE 2	5	4	0						75,000,000
00901		2015-0189	2-10 MILLION GALLON FINISHED WATER STORAGE RESERVOIR	3	3	0						
00901	512627470	2015-0713	HVAC UPGRADES IN FILTER ROOM	5	5	45,044						
00901	512627457	2016-1279	PLANT LIGHTING	5	4	30,000						
00901		2018-1099	FILTER ASSESSMENT AND IMPROVEMENTS	5	4	0	1,500,000					
						$ 904,685	$ 4,300,000	$ 5,000,000	$ 2,500,000	$ 2,000,000	$ 2,000,000	$ 156,750,000
			TOTAL TREATMENT PLANTS			$ 5,670,028	$ 7,850,000	$ 17,750,000	$ 6,000,000	$ 5,500,000	$ 5,500,000	$ 344,750,000
51-01301-	2720.35		**PUMPING PLANTS AND PUMP HOUSES**									
01301	513416331		EAST BENCH PUMP STATION - FULL BACKUP POWER	5	5	623,996						
01301		2016-1174	5TH AVE AND U ST PUMP STATION BACKUP POWER	5	5	0	400,000					
01301	513416364	2016-1282	BONNEVILLE AND EAST BENCH PUMP STATION - PUMP UPGRADES	5	5	24,000						
01301	513416365	2015-0514	NORTH BENCH PUMP STATION ROOF	4	5	27,494						
01301	513505271	2015-0378	UPLAND DR PROJECT	4	5	0	800,000					
01301	513800033	2015-0555	3900 SOUTH BIRCH DRIVE VALVE VAULT	4	4	8,142						
01301	513416359	2016-0888	3900 SOUTH PUMP STATION	4	4	313,408	30,000	3,600,000	7,200,000			
01301	513416366	2015-0531	GOLDEN HILLS PUMP STATION	3	5	90,000	60,000					
01301	513416367	2016-1208	5TH AND U PUMP STATION IMPROVEMENTS	4	4	12,981	275,000					
01301	513416361	2015-0563	OAKHILLS PUMP STATION - MCC - VFD - PUMP UPGRADE	3	3	0		550,000				
01301		2016-0937	ENSIGN DOWNS PS VFD	3	3	0			20,000			
01301	513416336	2015-0428	MP 3.12 B - 7800 SOUTH AUXILIARY POWER	3	3	0			305,000			
01301		2016-1179	300 EAST PUMP STATION BACKUP POWER	3	3	0			400,000			
01301		2016-1180	3300 SOUTH BOOSTER PUMP STATION BACKUP POWER	3	3	0			400,000			
01301		2016-1181	KENTON DRIVE PUMP STATION BACKUP POWER	3	3	0			400,000			
01301		2016-1183	VIRGINIA AND MILLCREEK PUMP STATION BACKUP POWER	3	3	0				400,000		
01301		2016-1184	EASTWOOD PUMP STATION BACKUP POWER	3	3	0				400,000		
01301		2016-1185	MILLCREEK PUMP STATION BACKUP POWER	3	3	0				400,000		
01301		2016-1186	39TH AND BIRCH PUMP STATION BACKUP POWER	3	3	0				400,000		
01301		2016-1187	CANYON COVE PUMP STATION BACKUP POWER	3	3	0					400,000	
01301		2016-1188	7800 SOUTH PUMP STATION BACKUP POWER	3	3	0					400,000	
01301		2016-1189	GOLDEN HILLS PUMP STATION BACKUP POWER	3	3	0					400,000	
01301		2016-1190	CARRIGAN COVE PUMP STATION BACKUP POWER	3	3	0					400,000	
01301		2016-1173	NORTH BENCH PUMP STATION BACKUP POWER	3	3	0						400,000
01301		2016-1175	UNIVERSITY PUMP STATION BACKUP POWER	3	3	0						400,000

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01301		2016-1176	RESEARCH PARK PUMP STATION BACKUP POWER	3	3	0						400,000
01301		2016-1177	OAK HILLS PUMP STATION BACKUP POWER	3	3	0						400,000
01301		2016-1178	BONNEVILLE PUMP STATION BACKUP POWER	3	3	0						400,000
01301		2016-1191	3900 SOUTH BOOSTER PUMP STATION BACKUP POWER	3	3	0						400,000
01301		2016-1192	6200 SOUTH IRRIGATION PUMP STATION BACKUP POWER	3	3	0						400,000
01301		2016-1193	EMIGRATION PUMP STATION BACKUP POWER	3	3	0						400,000
01301		2016-1223	5TH AVE AND U ST PUMP STATION VFD'S	3	3	0						200,000
01301		2016-1224	ARLINGTON HILLS PUMP STATION VFD'S	3	3	0						200,000
01301		2016-1225	NORTH BENCH PUMP STATION VFD'S	3	3	0					200,000	
01301		2016-1226	5TH AVE AND U ST PUMP STATION PIPING	3	3	0						200,000
01301		2017-2009	REPAIR AND LINE OF UNIVERSITY DRAIN LINE	2	3	0						10,000
01301		2015-0517	4500 SOUTH PUMP STATION BLACK TOP	1	3	0						25,000
01301		2015-0522	RECURRING PUMP STATION REPAIR FUND	3	0	0						50,000
01301	513416329	2015-0169	UV UPGRADE 6200 SOUTH PUMP STATION	1	2	0						300,000
01301		2016-1194	ENSIGN DOWNS PUMP STATION BACKUP POWER	3	0	0						400,000
01301		2015-0172	MP 3.8C - VICTORY ROAD - ENSIGN DOWNS PHASE II - PROPERTY PURCHASE - IF	4	0	0						500,000
01301		2015-0173	4500 SOUTH PUMP STATION (BACK UP)	5	0	0						1,500,000
						$ 1,100,021	$ 1,565,000	$ 4,150,000	$ 8,725,000	$ 1,600,000	$ 1,800,000	$ 6,585,000
51-01301-	2730.02		**CULVERTS FLUMES & BRIDGES**									
01301	5129264		JSL CANAL CONDUIT REPLACEMENT - SUGARHOUSE	5	5	67,976	1,000,000					
01301	513000045	2016-1166	SUGARHOUSE WELL SPLASH PAD	5	5	59,889	150,000					150,000
01301	512900272	2015-0432	VARIOUS CANAL IMPROVEMENTS	5	5	25,000	25,000	25,000	25,000	25,000	25,000	
01301	512900273	2016-0737	IRRIGATION SCADA IMPROVEMENTS	5	5	20,000	50,000	20,000	20,000	20,000	20,000	
01301		2016-0816	ROCKHOUSE DUMP - INTAKE IMPROVEMENT	5	4	0		78,500				
01301	513000034	2016-0858	FLUME FROM DOUBLE BARRELS TO RAILROAD TRACKS	4	4	21,512			1,250,000	1,250,000		
01301	5129246	2015-0158	REPLACE FLUME/AUTO DUMP AND JSL CANAL ENCLOSURE @ MILLCREEK	4	4	0	100,000	468,000				
01301	512900274	2017-2076	HEADGATE REHABILITATION 18/19	4	4	20,000	20,000	20,000	20,000	20,000	20,000	
01301	513000026	2015-0161	E JORDAN TOWER - IMPROVED ACCESS	3	5	20,000		150,000				
01301		2016-1167	6200 SOUTH LIFT STATION WEIR PROTECTION	3	5	0	60,000					
01301	5129231	2015-0152	JSL CANAL - 1750 S EMIGRATION DIVERSION STRUCTURE REBUILD	4	3	0				50,000	290,000	
01301	5129233	2015-0604	JSL 3800 S REHAB FLOOR AND LEAKAGE	3	4	0			18,000			
01301	5129251	2015-0151	JSL ENCLOSURE FROM 1300 EAST TO MILLCREEK	3	3	0						997,000
01301		2015-0168	IMPROVEMENTS TO JSL DUMP AT I-80	3	3	0						11,000
01301	5129235	2015-0606	JSL 4500 SOUTH TO OSAGE ORANGE DRIVE – CANAL BANK HYDRAULICS	3	3	0				20,000		
01301	5129249	2015-0149	NEW IRRIGATION CONDUIT ON HARVARD AVENUE	4	0	0			50,000		402,000	
01301	513000038	2016-0865	OIL SEPARATORS AND DRAINAGE SYSTEM FOR THE ARTESIAN SHOP	4	0	37,500		600,000				
01301		2016-1165	LOW FLOW CHANNEL AT SPENCER'S POND (BIG COTTONWOOD CREEK)	4	0	0					300,000	
01301		2016-1284	1100 EAST DIVERSION STRUCTURE AT WILLINGTON	4	0	0						50,000
01301	5129232	2015-0602	JSL CANAL – MODIFY BIG SPILL TO HANDLE TEMPORARY PUMP	2	2	0					82,000	
01301		2016-1287	STUDY ON WELLS AT WALKER LANE AND FOUNTAIN BEAU	1	3	0						1,000,000
01301		2016-0749	J&SL DIVERSION STRUCTURE AT 2700 SOUTH	2	0	0						350,000
01301		2016-1286	3000 EAST WELL FOR WATER DELIVERIES	2	0	0						2,000,000
01301	5129242	2015-0153	PIPING DITCH ON JSL, OSAGE ORANGE AVENUE TO LINCOLN LANE	1	0	0						175,000
01301		2015-0160	DESPAIN IRRIGATION SYSTEM IMPROVEMENTS	3	3	0						17,000
01301		2015-0603	JSL CANAL/JORDAN RIVER STABILIZATION AT EAST JORDAN DUMP	4	4	0						406,000
01301		2018-1019	14600 SO. CANAL OVER FLOW STRUTURE	3	3	0						500,000
01301		2018-1080	3900SO STORM DRAIN OVER FLOW	2	4	0				50,000	250,000	
01301		2018-1082	LITTLE TANNER PIPE PROJECT	2	0	0						50,000
			REHABILITATION/REPLACEMENT OF JSL IN CITY LIMITS				50,000	50,000	50,000	50,000	50,000	
						$ 271,878	$ 1,455,000	$ 1,411,500	$ 1,433,000	$ 1,485,000	$ 1,439,000	$ 5,706,000

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51-01301-	2730.04		**DEEP PUMP WELLS**									
01301	5132245	2015-0429	WELL ASSESSMENT AND UPGRADES	5	5	100,000	200,000	200,000	200,000	200,000	200,000	
01301	5132270	2015-0430	WELL BUILDING STRUCTURE UPGRADES	5	5	100,000	100,000	100,000	100,000	100,000	100,000	
01301	5132268	2015-0213	MP3.4 - 4TH AVENUE WELL ELECTRICAL IMPROVEMENTS	5	5	393,481	3,000,000					
01301	5132269	2015-0212	MP3.4 - 4TH AVENUE WELL/BRICK TANK IMPROVEMENTS	5	5	71,155						
01301	51322336	2015-0171	WELL TREATMENT PROJECT - 1500 EAST WELL	4	4	100,000	100,000					
01301		2016-0820	DYERS INN	4	4	0			550,000			
01301		2017-2071	DYER'S INN WELL FLUSH LINE	4	4	0			100,000			
01301		2016-0911	1300 E WELL CHLORINATION	3	4	0						400,000
01301		2015-0408	1300 EAST WELL FLUSH LINE	2	2	0			95,000			
01301	5132255	2015-0571	ARTESIAN WELL 2 REHAB	4	0	0						250,000
01301	5132249	2015-0565	19TH AND 27TH SOUTH WELL - VFD	3	0	0						60,000
01301	5132246	2015-0570	TREATMENT OF PCE AT WELLS	3	0	0						12,000,000
01301	5132241	2015-0569	RED BUTTE	2	0	0			2,500,000	60,000		2,500,000
01301	513223419		MT OLIVET IRRIGATION FEASIBLITY STUDY			3,464						
01301		2018-1038	4TH AVENUE WELL INSPECTION	4	2	0						40,000
01301		2018-1091	VAN WINKLE PROPERTY FENCE	1	5	0					20,000	
						$ 768,100	$ 3,400,000	$ 300,000	$ 3,545,000	$ 360,000	$ 320,000	$ 15,250,000
51-01301-	2730.06		**STORAGE RESERVOIRS**									
01301	5134506	2017-1290	MOUNTAIN DELL RESERVOIR SEDIMENT SAMPLING AND BASIN PRE DESIGN	5	4	1,588						
01301	5134510		PARLEY'S DIVERSION STRUCTURE - IMPROVE BOOM DEPLOYMENT LOCATION	5	3	5,000						
01301	5134476		CHEVRON OIL SPILL PROTECTION PROJECT			3,000						
01301	5134458	2015-0155	REHABILITATION OF MOUNTAIN DELL DAM	5	4	853,333	2,165,000					
01301	5134455	2015-0167	RED PINE DAM REHABILITATION	5	4	30,000						484,000
01301	5134467	2015-0154	MOUNTAIN DELL RESERVOIR - BYPASS PIPE LITTLE DELL TO PARLEY'S	5	0	1,003,384						
01301	512450071	2017-2094	NEW ACTUATORS FOR THE PARLEYS CREEK DIVERSION STRUCTURE	5	0	17,714						
01301	5134468	2015-0607	LITTLE DELL RESTORE PARLEY'S DIVERSION EXTERIOR COATING	4	4	4,725						
01301	5124512	2015-0209	REPLACE VALVES ON MT. DELL DAM	4	4	0						320,000
01301	512700001	2017-2080	REABILITATION OF THE LAKE MARY GAUGE	3	5	1,161						
01301	512700005	2016-1272	CECRET DAM REHABILITATION - DESIGN	4	3	32,525						2,000,000
01301	512700002	2017-2082	REPAIRS TO TWIN LAKES DAM GAUGE	3	4	1,545						
01301	512700003	2017-2079	REPAIRS AND IMPROVEMENTS TO RED BUTTTE DAM ROAD	3	4	30,000						
01301	5134478	2015-0164	LITTLE DELL DAM - INSTALL NEW DRAINS ON THE PORTAL	3	3	0						27,000
01301		2016-1278	SECURITY CAMERAS AT LITTLE DELL	3	3	0						50,000
01301	5134457	2015-0166	NEW STAFF GAGE AT LITTLE DELL DAM	3	3	0						153,000
01301	5124509	2015-0451	STAIRS MT DELL DAM	2	3	0						75,000
01301		2015-0208	CONDUIT FROM DAM TO OLD ICB TO PLANT	2	2	0						20,000
01301	5134466	2015-0156	PARLEY'S CANYON HYDROPOWER PROJECT	1	0	0	100,000	900,000	200,000			
01301	512700006		LITTLE DELL PENSTOCK: PHASE 2			1,000,054						
01301		2018-1034	SPILL PROTECTION PROJECT - I-80 AT LAMB'S CANYON	5	0	0						240,000
01301		2018-1100	LAKE MARY DAM CREST REHABILITATION	5	5	0	20,000					100,000
01301		2018-1101	TWIN LAKES DAM GAUGE RELOCATION	3	4	0						20,000
01301		2018-1102	TWIN LAKE AND LAKE MARY OUTLET CHANNEL IMPROVEMENTS	5	5	0	15,000	50,000	50,000			
01301		2018-1103	PARLEYS CANYON CONDUIT AND FIBER INSTALLATION	4	0	0	100,000					100,000
01301		2018-1104	TWIN LAKES DAM DRAIN CLEANOUT INSTALLATION	4	5	0	40,000					40,000
01301		2018-1105	TWIN LAKES AND LAKE MARY LOG BOOMS	3	5	0						10,000
01301		2018-1106	MOUNTAIN DELL DAM SPILLWAY REHABILITATION	5	4	0	100,000					100,000
01301		2018-1107	LITTLE DELL DAM RODENT ERADICATION	4	4	0	50,000					30,000
01301		2018-1108	LITTLE DELL DAM STAFF GAUGE	3	0	0						175,000
01301		2018-1109	CECRET LAKE FLOW METER AND TELEMETRY	4	0	0						60,000
						$ 2,984,028	$ 2,590,000	$ 950,000	$ 250,000	$ -	$ -	$ 4,004,000

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51-01301-	2730.07		DISTRIBUTION RESERVOIRS									
01301	513444163	2017-2060	NEFF'S TANK OVERFLOW DRAIN	5	5	81,064						
01301	513444164	2017-2067	MARCUS RESERVOIR TANK UPGRADES	5	5	7,500						1,000,000
01301	513444161	2017-2074	EASTWOOD NORTH - INTERIOR COATING	5	5	128,632						
01301	513444162	2015-0527	FERGUSON TANK UPGRADE	5	5	14,511	150,000					
01301	513444166	2015-0573	AM - TANK AND RESERVOIR INSPECTIONS AND REPAIRS	5	5	100,000	100,000	100,000	100,000	100,000	100,000	100,000
01301	513444165	2015-0409	MOUNT OLYMPUS TANKS DRAIN/OVERFLOW STRUCTURE	5	4	72,580						
01301	5134507	2016-1171	FORT DOUGLAS IMPROVEMENTS/EXPANSION	5	4	163,424		4,000,000				1,500,000
01301	513444159	2015-0174	MILITARY RESERVOIR REPAIR	5	3	0						11,020,000
01301		2015-0406	EMIGRATION TUNNEL POWER	4	4	0						45,000
01301	513444168	2017-2111	TANNER RESERVOIR ROOF REPLACEMENT/FULL REPLACEMENT	4	4	6,800	100,000	1,000,000				
01301		2015-0719	DISTRIBUTION TANK AND RESERVOIR PAVING	4	4	0	80,000	80,000	80,000	80,000	80,000	
01301		2016-0753	BASKIN OVERFLOW/DRAIN GOOSENECK BOX	4	4	0			100,000			
01301		2017-2061	TETON TANKS SLOPE STABILIZATION	4	3	0		50,000				
01301		2015-0525	PERRY HOLLOW TANK	2	5	0	65,000					
01301	5134471	2015-0459	TANK PAINTING AND CORROSION CONTROL	3	3	100,000	200,000	200,000	200,000	200,000	200,000	
01301		2016-0935	ENSIGN DOWNS OVERFLOW	3	3	0						150,000
01301		2015-0516	MOUNT OLYMPUS TANKS & PUMP STATION BLACKTOP	2	4	0						25,000
01301		2015-0499	RAINER TANK	2	2	0						280,000
01301		2016-0917	ENSIGN DOWNS LOWER RESERVOIR MODIFICATIONS	2	2	0						200,000
01301		2015-0520	NORTH BENCH TANK ROAD	1	3	0						45,000
01301		2015-0526	VICTORY ROAD	1	3	0						22,000
01301		2016-0754	CAPITOL HILLS TANKS - TRUCK ACCESS	3	0	0						200,000
01301	513444167	2017-2121	TELFORD RESERVOIR SAFETY IMPROVEMENTS	1	2	1,234						
01301		2015-0528	NEFFS CANYON TANK	1	3	0						55,000
01301		2015-0529	EMIGRATION TANK UPGRADES	1	2	0						60,000
01301		2015-0530	TETON TANK UPGRADES	1	2	0						35,000
01301		2015-0458	MISCELLANEOUS REPAIRS	3	2	0			50,000			
01301		2017-2010	COVE TANK STABILIZATION PROJECT	2	3	0			200,000			
01301		2017-2012	TELFORD FENCE	3	0	0					30,000	
01301		2017-2013	EAST BENCH TANKS DRAIN LINE GOOSENECK	1	3	0					25,000	
01301		2017-2059	VICTORY ROAD TANK OVERFLOW DRAIN	4	4	0		50,000				
01301		2017-2064	CARRIGAN COVE TANK POWER	2	3	0				50,000		
01301		2017-2112	GRANITE OAKS/TELFORD RESERVOIR REPAIRS	3	3	0			50,000			
01301		2017-2118	GRANITE OAKS ACCESS ROAD	1	4	0			100,000			
01301		2018-1023	BASKIN RESERVOIR EFFLUENT PIPE	4	4	0		500,000				
01301		2018-1024	BASKIN ROOF REPLACEMENT	5	5	0	50,000					
01301		2018-1026	TANK AND RESERVOIR FALL PROTECTION SYSTEMS	5	0	0	100,000					
01301		2018-1031	MILITARY RESERVOIR - JOINT SEALANT REPAIR	5	4	0		20,000				
01301		2018-1032	MILITARY RESERVOIR - REPAIR INLET/OUTLET PIPE	5	4	0		50,000				
01301		2018-1033	MILITARY RESERVOIR CONDITION ASSESSMENT	5	4	0		20,000				
01301		2018-1092	FENCE 300 EAST GORDON LANE	1	4	0				5,000		
						$ 675,745	$ 845,000	$ 6,070,000	$ 880,000	$ 435,000	$ 435,000	$ 14,737,000
51-01301-	2730.08		DISTRIBUTION MAINS & HYDRANTS									
			CITY, COUNTY, STATE AND MISC. DRIVEN PROJECTS									
01301	513505272	2016-1233	WATER MAIN REPLACEMENT - 900 SOUTH	5	5	0	800,000					
01301	513505273	2016-0744	1300 EAST - WATER LINE	3	4	2,417,148						
01301	513505312	2015-0431	CITY/COUNTY/STATE DRIVEN PROJECTS	5	5	250,000	350,000	350,000	350,000	350,000	350,000	
01301		2016-1264	NW QUADRANT (DEVELOPMENT) PIPE UPSIZE	5	5	0						1,400,000
01301	513600099	2017-2056	ENERGY EFFICIENCY/RENEWABLE ENERGY CAPITAL IMPROVEMENTS	5	5	200,000	200,000	200,000	200,000	200,000	200,000	

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01301	513505308	2015-0398	UPPER CONDUIT METER REPLACEMENT	4	5	50,000						
01301	513600097	2017-2014	MOTORS AT WORK	4	4	16,000						
01301	513505230	2015-0245	EAST INDIANA AVENUE (850 SOUTH) - REDWOOD RD TO SURPLUS	3	5	149,072	985,000					
01301	513505332		CITY CREEK WATER MAIN VAULT REMOVAL			25,000						
01301		2018-1081	STATE IPS RESOLUTIONS	4	4	0	20,000	20,000	20,000	20,000	20,000	
01301	513505334		STATE "BETTERMENT" PROJECT, WATER LINE CROSSING 5600 WEST AT 1100 SOUTH			0	72,600					
01301			STATE 1100 SOUTH, 5600 WEST TO LEGACY VIEW (ABOUT 5700 W)			0	25,000					
			700 WEST - 1600 SOUTH TO 2100 SOUTH				100,000					
			LOCAL STREET DISTRICT 1 & 7				200,000					
			800 WEST - 600 SOUTH TO 800 SOUTH				350,000					
			500 EAST - 1700 SOUTH TO 2100 SOUTH				950,000					
			2000 EAST - PARLEY'S TO CITY LIMIT				300,000					
			1900 EAST - WILMINGTON TO PARLEYS CANYON				250,000					
			900 SOUTH - 900 WEST TO 900 EAST				5,000,000					
			300 WEST - 600 SOUTH TO 2100 SOUTH				2,500,000					
			LOCAL STREETS DISTRICT 3 & 6					200,000				
			900 EAST - HOLLYWOOD TO 2700 SOUTH					340,000				
			100 SOUTH - NORTH CAMPUS DRIVE TO 900 EAST					390,000				
			1700 EAST - 1700 SOUTH TO 2700 SOUTH					60,000				
			LOCAL STREETS DISTRICTS 2 & 5						200,000			
			200 SOUTH - 400 WEST TO 900 EAST						4,000,000			
			1100 EAST HIGHLAND , RAMONA TO WARNOCK							1,000,000		
			LOCAL STREETS DISTRICT 4 & 7							200,000		
			1100 EAST - 900 SOUTH TO RAMONA							4,000,000		
			300 NORTH - 300 WEST TO 1000 WEST							1,500,000		
			W TEMPLE - NORTH TEMPLE TO 400 SOUTH								800,000	
			LOCAL STREETS 3 & 6								200,000	
			VIRGINIA STREET - SOUTH TEMPLE TO 11TH AVE								100,000	
			1300 EAST - 2100 SOUTH TO 3000 SOUTH									
			2100 SOUTH - 700 EAST TO 1700 EAST									2,500,000
			LOCAL STREETS DISTRICT 1, 4 & 5									200,000
			GLADIOLA STREET - 900 SOUTH TO CALIFORNIA									50,000
			300 WEST - 400 SOUTH TO 900 SOUTH									2,000,000
			WAKARA WAY - FOOTHILL DRIVE TO CHIPETA WAY									150,000
						$ 3,107,220	$ 12,102,600	$ 1,560,000	$ 4,770,000	$ 7,270,000	$ 1,670,000	$ 6,300,000
			WATER MAIN MISCELLANEOUS PROJECTS									
01301	514500020	2015-0491	REGULATOR REPLACEMENT	5	5	20,000	300,000	300,000	300,000	300,000	300,000	
01301	513302118	2015-0493	NEW MAINLINE VALVES - COUNTY	5	5	138,000	138,000	138,000	138,000	138,000	138,000	
01301	513505311	2015-0489	NEW WATER LINES - CONTRIBUTIONS BY DEVELOPERS	5	5	500,000	500,000	500,000	500,000	500,000	500,000	
01301	513505310	2015-0490	FIRE HYDRANT REPLACEMENTS	5	5	400,000	400,000	400,000	400,000	400,000	400,000	
01301	513505309	2015-0492	NEW MAINLINE VALVES - CITY	5	5	262,000	262,000	262,000	262,000	262,000	262,000	
01301	513505304	2018-1002	UPPER CONUIT - LINE SYPHON	5	4	329,549	3,000,000					
01301	514500019	2016-0961	4TH AND A PRV	4	5	178,665						
01301		2016-0958	10TH AND B PRV	3	4	0		210,000				
01301		2016-0751	RECONNECTION OF 1700 SOUTH AND FOOTHILL UTILITIES	2	4	0			20,000			
01301	513600098	2017-2072	SAMPLING TAPS	3	3	50,000	10,000	10,000	10,000			
01301		2016-0923	SAM PARK INLET VAULT	3	3	0			35,000			
01301		2016-0959	10TH AND E PRV	3	3	0			210,000			
01301		2016-0960	8TH AND L PRV	3	3	0						210,000
01301		2016-0914	CONNECTIONS AT RR	4	0	0						440,000
01301	513600103		CORROSION CONTROL PROGRAM			47,653						
01301	514506		1000 EAST 500 SOUTH PRV			0	1,500,000					

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						$ 1,925,867	$ 6,110,000	$ 1,820,000	$ 1,875,000	$ 1,600,000	$ 1,600,000	$ 650,000
			WATER MAIN REPLACEMENTS									
01301	513505314		SMALL DIAMETER PIPE REPLACEMENT PROGRAM	5	5	250,000	250,000	250,000	250,000	250,000	250,000	
01301	513505203	2015-0247	600 WEST - 600 NORTH TO RAILROAD CROSSING	5	4	187,620						
01301	513505216		1000 NORTH - 1500 WEST TO REDWOOD ROAD	4	5	0	300,000					
01301	513302017	2015-0618	900 EAST AND 5600 SOUTH WATER MAIN REPLACEMENT	5	5	1,249				1,500,000		
01301	513302116	2016-0739	MILLCREEK WAY WATER MAIN REPLACEMENT	5	5	28,500	190,000					
01301	513505306	2017-2063	SCENIC DRIVE UPPER CONDUIT SLIPLINE PROJECT	5	5	0	300,000					3,000,000
01301	513505208	2015-0240	J STREET - SUNRISE AVENUE TO NORTHCREST DRIVE	5	4	492,260						
01301		2016-0921	BACKFEED FOR UTAH STATE CAPITOL	5	4	0		60,000				
01301		2016-1234	SHED AT EMIGRATION WELL	5	4	0			50,000			
01301	513505151	2015-0543	700 SOUTH - 300 WEST TO 700 WEST	5	4	0	630,000					
01301	513505156	2015-0233	200 SOUTH - 600 WEST TO JEREMY STREET	4	5	0	413,500					
01301	513505193	2015-0235	BECK STREET - 1805 NORTH TO 1180 NORTH	4	5	0						1,247,000
01301	513505207	2015-0252	3390 SOUTH - 700 EAST TO RIVIERA DRIVE	4	5	80,000	175,000					
01301	513504858	2015-0547	DULUTH AVE (1550 N) - 900 W TO DEXTER, 900 W - 1500 N TO DULUTH	4	5	1,688	175,000					
01301	513505130	2015-0549	FOOTHILL DRIVE - EMERSON AVE TO KENSINGTON AVE	4	5	0	105,000					
01301	513302047	2015-0617	MILLSTREAM DRIVE (3580 S) - MARDONNA WAY TO EASTWOOD DRIVE	4	5	0	274,000					
01301	513505133	2015-0624	1700 SOUTH - 1000 EAST TO 1100 EAST	4	5	0		160,000				
01301		2016-1230	17TH AND FOOTHILL TELEMETRY AND POWER	4	5	0			200,000			
01301		2015-0255	REDWOOD ROAD - 500 SOUTH TO 1050 SOUTH	4	5	0			918,000			
01301	513505212	2015-0253	PLEASANT VALLEY LINE	4	5	0						653,000
01301		2015-0254	CITY CREEK HIGHLINE	4	5	0						460,000
01301		2015-0554	SOUTH TEMPLE 1000 W.(GATSPY LINE)	5	3	0						415,000
01301	513505198	2015-0237	GREGSON AVENUE - 2465 EAST TO 2700 EAST	4	4	0						80,000
01301	513302089	2015-0238	2300 EAST - 6200 SOUTH TO 6400 SOUTH	4	4	0						268,000
01301	513505202	2015-0246	420 N MAIN STREET - 1" SERVICE REPLACEMENT - MAIN ST TO WALL ST	4	4	0						64,000
01301	513505125	2015-0260	WEST TEMPLE - 500 SOUTH TO 800 SOUTH (EAST SIDE)	4	4	0						469,000
01301	513505127	2015-0262	1000 WEST/1400 SOUTH WATER MAIN REPLACEMENT	4	4	0						560,000
01301		2017-2022	2880 SOUTH WATER MAIN REPLACEMENT	4	4	0						260,000
01301	513505197	2015-0236	800 SOUTH - 1200 EAST TO 1220 EAST	3	5	0						134,000
01301	513302039	2015-0613	OAK CREEK DRIVE - 8200 SOUTH TO END OF LINE	3	5	0						300,000
01301	513302045	2015-0616	MARDONNA WAY (3545 S) - SUNILAND DRIVE TO MILLSTREAM DRIVE	3	5	0						153,000
01301	513505128	2015-0620	WILTON WAY WATER MAIN REPLACEMENT	3	5	0						374,000
01301	513505129	2015-0621	1700 SOUTH - FOOTHILL TO WASATCH WATER MAIN REPLACEMENTS	3	5	0						257,000
01301	513505132	2015-0622	MILTON AVENUE (1595 SOUTH) - 1100 EAST TO 1200 EAST	3	5	0						179,000
01301		2017-2066	2700 E DEAD-END CONNECTION	3	5	0						20,000
01301		2016-0738	RELOCATE 12" CIP MAIN FROM UNDER HOUSE (EAST BENCH SUCTION LINE)	5	2	0						255,000
01301	513302090	2015-0239	COBBLECREST RD - 6380 S TO 2300 E; HAUN AVE - 2300 E TO COBBLECREST	4	3	0						411,000
01301		2015-0232	NORTH TEMPLE - 1800 WEST TO REDWOOD ROAD	4	3	0						156,200
01301	513505155	2015-0241	WESTMINSTER AVENUE - LAURELHURST (2550 EAST) TO FOOTHILL BOULEVARD (2600 EAST)	4	3	0						90,000
01301	513302038	2015-0258	BISCAYNE DR (2975 E) - BENGAL BLVD TO OAKVIEW CIR	4	3	0						158,000
01301	513505122	2015-0550	DUPONT AVE (1335 N) - AMERICAN BEAUTY DR TO 990 W	4	3	0						115,000
01301		2016-1228	REPLACE PRV'S - R11 AND R12	4	3	0						400,000
01301	513505205	2015-0249	SCOTT AVENUE - 700 EAST TO SCOTT PARK LANE	3	4	0						105,000
01301		2015-0400	R37. MAYWOOD REGULATOR	3	4	0						150,000
01301	513505134	2015-0625	BRYAN AVENUE (1565 SOUTH) - 900 EAST TO 1000 EAST	3	4	0						172,000
01301		2016-0889	CR1 PRV	3	4	0						225,000
01301		2016-0890	CR2 PRV	3	4	0						225,000
01301		2016-0891	HYDRANT 3300 SOUTH	3	4	0						40,000
01301		2016-0901	PRV E3-R49 REPLACEMENT	3	4	0						220,000
01301		2016-0910	HIGHLAND DRIVE REGULATORS	3	4	0						1,300,000

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01301		2016-0912	R73 REPLACEMENT	3	4	0						200,000
01301		2016-0913	CUP REGULATORS	3	4	0						300,000
01301		2016-0918	2300 EAST - CLAYBOURNE TO 3300 SOUTH	3	4	0						200,000
01301		2016-0934	PRV AT 17TH	3	4	0						210,000
01301		2016-1169	J STREET PIPELINE AND PRV REPLACEMENT	3	4	0						300,000
01301		2016-1273	NEW WATER MAIN - 1000 EAST	3	4	0						300,000
01301		2017-2062	ROXBURY PRV C46-R66	3	4	0						150,000
01301		2017-2065	CAMILLE ST. DEAD-END CONNECTION	3	4	0						20,000
01301		2016-1283	SUICIDE ROCK RUNAROUND	2	5	0						25,000
01301	513302117	2017-2069	CAP STUB AT 6200 SOUTH HOLLADAY BOULEVARD	3	3	2,250						
01301	513505124	2015-0619	BUCCANEER DRIVE WATER MAIN REPLACEMENT	3	3	0						151,000
01301		2016-0748	WATER VALVE REPLACEMENT PROJECT #3	2	4	0						100,000
01301	513505199	2015-0242	700 EAST - DRIGGS AVE (2370 S) TO WARNOCK AVE (2470 S)	1	5	0						257,000
01301		2015-0256	900 EAST HILLVIEW (4060 SOUTH) - REPLACE DIP MAIN UNDER SEWER	1	5	0						36,000
01301		2016-0756	300 WEST - 700 S TO 800 S	1	5	0						175,000
01301		2016-0892	KEARNS LINE REPLACEMENT	3	3	0						8,000,000
01301		2016-0900	R48 VALVE	3	3	0						20,000
01301		2016-0906	6-INCH ON 9TH	3	3	0						450,000
01301		2016-0915	SMITHS CONNECTION	3	3	0						70,000
01301		2016-0916	COUNTRY CLUB PRV	3	3	0						250,000
01301		2016-0933	MAYWOOD 6-INCH	3	3	0						220,000
01301		2016-0936	16-INCH VALVE VAULT	3	3	0						65,000
01301		2016-1222	PRV REPLACEMENT - A8-14	3	3	0						200,000
01301		2016-1231	NEW PRV - R73	3	3	0						200,000
01301		2016-1232	NEW PRV - R74	3	3	0						200,000
01301		2016-1235	POWER AT EMIGRATION TUNNEL	3	3	0						100,000
01301		2015-0399	RESEARCH PARK UPGRADE	5	0	0						410,000
01301		2016-0919	INSERTA VALVES	5	0	0						50,000
01301		2017-1299	EDWARD DRIVE REGULATED IMPROVEMENTS	5	0	0						500,000
01301		2017-2068	INDIAN ROCK PRESSURE ZONE REDUNDANT FEED	5	0	0						250,000
01301		2017-2070	HIGHLAND DR WATER MAIN - 6200 S TO DIAMOND HILLS LN	3	2	0						250,000
01301	513302046	2015-0615	SUNILAND DRIVE (3550 E) - MILLSTREAM LANE TO END OF SUNILAND CIRCLE	3	2	0						149,000
01301		2015-0426	FORT UNION AND HIGHLAND AVE INTERSECTION	2	3	0						302,500
01301		2017-2011	900 EAST FROM VAN WINKLE TO 5600 SOUTH	2	3	0						100,000
01301	513505204	2015-0248	500 SOUTH - 2130 WEST TO ORANGE STREET	4	0	0						315,000
01301	513302021	2015-0250	6200 SOUTH - 2900 EAST TO 3000 EAST	4	0	0						350,000
01301	513302058	2015-0544	SHORT HILLS DR (3375 E) - 8220 SOUTH TO 8315 SOUTH	4	0	0						55,000
01301		2015-0397	SUICIDE ROCK VAULT	2	2	0						100,000
01301		2016-0925	2700 E CONNECTION	2	2	0						60,000
01301		2015-0480	1700 EAST FROM FT UNION BLVD (6935 S) TO 7080 SOUTH	1	3	0						360,000
01301	513302059	2015-0548	3900 SOUTH - 900 EAST TO 940 EAST	3	0	0						130,000
01301		2015-0586	PARLEY'S CANYON BLVD 1700 EAST TO 1800 EAST	3	0	0						181,000
01301	513505166	2015-0626	400 EAST - 1497 SOUTH TO 1530 SOUTH	3	0	0						37,000
01301	513505167	2015-0627	1400 EAST - GILMER AVENUE TO YALE AVENUE	3	0	0						32,000
01301		2016-0957	MORRIS PUMP STATION	3	0	0						600,000
01301		2016-1168	KEARNS VALVE	3	0	0						30,000
01301		2015-0413	700 NORTH 8" AC	2	1	0						115,000
01301		2015-0641	LITTLE COTTONWOOD CREEK CEMENT CAP 4"	1	2	0						35,000
01301		2015-0407	2200 WEST WATER MAIN EXTENSION	1	0	0						255,000
01301	514000040		ASPHALT PATCHING 2018			30,000						
01301		2018-1096	CHEYENNE STREET WATER LINE REPLACEMENT	3	4	0			50,000			
01301		2016-0856	7000 SOUTH SAND TRAP AND SCREEN REMOVAL	5	5	0		20,000				
01301		2018-1041	UPPER BOUNDARY SPRINGS EFFLUENT LINE REPLACEMENT FROM SPRING BOX TO TANK	4	5	0		500,000				
01301		2017-2018	DULUTH AVE AND 900 WEST WATER MAIN REPLACEMENT	3	5	0	325,000		400,000			

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01301		2017-2110	DEVELOPER DRIVEN PROJECTS	4	4	0	100,000					
01301		2018-1079	2100 SOUTH, 700 EAST TO 1300 EAST, WATER LINE REPLACEMENT	3	4	0		1,800,000				
01301		2018-1089	EAST BENCH SUCTION LINE RELOCATION	4	2	0			96,400			
						$ 1,073,567	$ 3,237,500	$ 2,790,000	$ 1,964,400	$ 1,750,000	$ 250,000	$ 29,780,700
			MASTER PLAN PROJECTS									
01301	513416337	2015-0629	MP3.16 - NORTH BENCH PUMP STATION	5	5	15,065			1,500,000			
01301	513505088	2015-0217	CITY CREEK TREATMENT LINE TO MORRIS RESERVOIR	5	4	0	80,000		800,000			
01301	513302020	2015-0230	3RD EAST PHASE II - MARCUS TO ARTESIAN BASIN	4	4	266,503	4,000,000					
01301	51360062	2015-0632	MP2.3 - WASTEWATER REUSE	4	3	0						23,000,000
01301	513505116	2015-0633	MILLCREEK TREATMENT PLANT LINE - TANK TO WASATCH BLVD (24")	4	3	0						750,000
01301	513416327	2015-0218	MP 3.5B - 16" PIPELINE ON NEWPORT WAY/NANTUCKET DRIVE	4	2	0						394,000
01301	513302063	2015-0224	MP 3.5A - 12" PIPELINE ON HIGHLAND DR (6200 S HIGH ZONE)	3	3	0						317,000
01301		2015-0229	MP 3.17 - 8" LOOP AT 2200 WEST/2200 NORTH	5	0	0						948,000
01301	513505159	2015-0222	MP3.14 - AUXILIARY POWER - GOLDEN HILLS	5	0	0						45,000
01301	513505168		CAPITOL HILL TO ENSIGN DOWNS PIPELINE	4	0	0						5,000,000
01301	513302062	2015-0219	MP3.9 - NEW PUMP STATION - TETON TO MT. OLYMPUS/4500 SOUTH HIGH - IF	4	0	0						695,000
01301	513302061	2015-0220	MP3.6B - 12" PIPELINE ON BRIGHTON WAY	4	0	0						200,000
01301	513505117	2015-0221	MP3.5C - 16" PIPELINE ON BENGAL BOULEVARD	4	0	0						1,134,000
01301	513505098	2015-0225	MP3.1A - EAST-WEST CONVEYANCE LINE - PARK RESERVOIR TO SUGARHOUSE PARK	4	0	299,181	10,000,000	10,000,000				
01301		2015-0231	MP 3.8C - VICTORY ROAD - ENSIGN DOWNS PHASE II - IF	4	0	0						2,250,000
01301	5134493	2015-0634	MP3.1B - EAST WEST CONVEYANCE LINE - SUGARHOUSE PARK TO 900 WEST	4	0	0						7,000,000
01301	5134464	2015-0227	MP3.7 - ADD THROTTLING CONTROL VALVE INTO WILSON RESERVOIR	3	0	0						150,000
01301		2015-0538	MP 3.12A - 7800 SOUTH PRESSURE ZONE - 4.3 MG RESERVOIR	2	0	0						3,000,000
01301	51360060	2015-0636	MP2.1 - DEVELOP ADDITIONAL GROUND WATER SOURCES	2	0	0						18,000,000
01301	513505169	2015-0630	MP2.2 - ADDITIONAL SURFACE WATER DEVELOPMENT	2	0	0						12,000,000
01301	51360061	2015-0635	MP3.1C - EAST WEST CONVEYANCE LINE - 900 WEST TO 3400 WEST (PHASE 3)	1	0	0						12,000,000
01301		2015-0631	MILLCREEK WATER TREATMENT FACILITY	1	0	0						80,000,000
01301			UPDATE WATER MASTER PLAN			0			400,000			
						$ 580,749	$ 14,080,000	$ 10,000,000	$ 2,700,000	$ -	$ -	$ 166,883,000
			TOTAL DISTRIBUTION MAINS & HYDRANTS			$ 6,687,404	$ 35,530,100	$ 16,170,000	$ 11,309,400	$ 10,620,000	$ 3,520,000	$ 203,613,700
	2730.09		**WATER SERVICE CONNECTIONS**									
03301	513900116	2015-0534	2700 EAST - RELOCATE SERVICE CONNECTIONS	3	3	7,227						
01701	513900126	2015-0494	SERVICE LINE REPAIR/REPLACEMENTS	5	5	1,800,000	1,800,000	1,800,000	1,800,000	1,800,000	1,800,000	
03301	513900125	2015-0495	NEW SERVICE CONNECTIONS	5	5	400,000	400,000	400,000	400,000	400,000	400,000	
02201	513900124	2015-0496	LARGE METER REPLACEMENTS	5	5	400,000	400,000	400,000	400,000	400,000	400,000	
02601	513900123	2015-0498	METER REPLACEMENT PROGRAM	5	5	200,000	200,000	200,000	200,000	200,000	200,000	
	513900120		AMI TOWERS - CITY	4	0	97,219						
	513900121	2017-2122	AMI TOWERS - COUNTY	4	0	123,711						
	513900122	2017-2126	AMI METER REPLACEMENT PROGRAM	1	0	3,100,000	3,100,000	3,100,000	3,100,000	3,100,000	3,100,000	
						$ 6,128,156	$ 5,900,000	$ 5,900,000	$ 5,900,000	$ 5,900,000	$ 5,900,000	$ -
	2730.20		**LANDSCAPING**									
			WATERSHED									
00601	5122672	2017-1295	RECREATION AREA PICNIC TABLE REPLACEMENT	5	5	3,750						
00601	5122673	2015-0670	ACCESSIBILITY UPGRADES TO WATERSHED RECREATION FACILITIES	5	0	38,069		200,000		200,000		
	512627466	2017-2032	SILVER LAKE RESTROOM DEMOLISH AND REPLACE	5	5	290,784						

WATER UTILITY CIP BUDGET
Five Year Projected Budget FY2020-2024

COST CENTER	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	CRITICALITY RATING	CONDITION RATING	PAST YEAR SPENT 2018-19 (Calc'd from P6)	BUDGET YEAR 2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
00601	512627463	2017-1296	BIG COTTONWOOD CANYON PARK & RIDE RESTROOM REBUILD	5	5	0		500,000				
	514700004	2017-2117	CITY CREEK ROADWAY ASPHALT	5	5	0	100,000	100,000				
03201	51360014	2015-0519	WEST TEMPLE CAMPUS - CONSERVATION IMPROVEMENTS	2	4	11,250						
		2018-1028	CITY CREEK CANYON ROAD RECONSTRUCTION	5	5	0			500,000	1,000,000	1,000,000	1,000,000
		2018-1110	SITE 30 PAVILION STRUCTURAL REVIEW	2	4	0	20,000					
			CITY CREEK WATER SYSTEM TO SITES 23 THROUGH 30									500,000
						$ 343,852	$ 120,000	$ 800,000	$ 500,000	$ 1,200,000	$ 1,000,000	$ 1,500,000
			TOTAL CAPITAL IMPROVEMENTS			$ 24,629,211	$ 59,255,100	$ 53,501,500	$ 38,542,400	$ 42,350,000	$ 29,914,000	$ 596,995,700

WATER UTILITY CAPITAL PURCHASES BUDGET
Five Year Projected Budget FY2020-2024

COST CENTER	OBJECT CODE	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	Comments	CRITICALITY RATING	CONDITION RATING	PAST YEAR BUDGET 2018-19	BUDGET YEAR 2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
	2710.10			**LAND**										
5103301	2710.10		2015-0427	WATERSHED PROPERTY		5	0		1,500,000	1,500,000	1,500,000	1,500,000	1,500,000	1,500,000
5103301	2710.10		2015-0481	1811 WEST 500 SOUTH		5	5							
5103301	2710.10			2668 EAST COMANCHE DRIVE										
5103301	2710.10			983 N PINECREST CANYON ROAD EMIGRATION CANYON										
5103301	2710.10		2015-0172	MP 3.8C - VICTORY ROAD - ENSIGN DOWNS PHASE II - PI		4	0	590,737						
								$ 590,737	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000	$ 1,500,000
	2710.30			**WATER RIGHTS & SUPPLY**										
5103301	2710.30			2,552 SHARES HILL DITCH @ $475				1,212,200						
5103301	2710.30			Various					30,000	30,000	30,000	30,000	30,000	
5103301	2710.30		2015-0488	56 SHARES UPPER CANAL IRRIIGATION @ $400		2	2	22,400						
								$ 1,234,600	$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ 30,000	$ -
	2750.10		Replace No.	**AUTOMOBILES & TRUCKS**										
5100101	2750.10		New	Ford F550 1 Ton C&C w/Bed Cost Center				49,000						
5100601	2750.10		31136	CHEVROLET 3/4 TON PICK-UP TRUCK				28,961						
5100601	2750.10			2019 F350 CHASSIS XL 4X4 SD				31,640						
5100601	2750.10			SNOW PLOW				4,908						
5100601	2750.10			RUGBY DUMP BODY				7,858						
5100701	2750.10			UTV - Brutis				29,007						
5100701	2750.10			FORD F-350 CREW CAB 4X4 SHORT BED				31,299						
5100701	2750.10			SNOW PLOW				4,520						
5100701	2750.10			SALT SPREADER				4,804						
5100801	2750.10		31117	GMC 3/4 Ton Cab-n-Chassis Flat Bed to Plow				44,195						
5101301	2750.10		31068	ESCAPE SUV 4X4				22,507						
5101301	2750.10			INSPECTION VEHICLES (2)				60,575						
5101301	2750.10			2018 FORD FOCUS ELECTRIC 4DR				28,287						
5101401	2750.10		31016	Chevrolet 3/4 Ton Pick-up Truck w/ Lift Gate				37,831						
5101401	2750.10		31005/31006/31009	3/4 P U/ replace w/1/4 Ton Pick-up 2wd (3)				66,483						
5101401	2750.10		31095/31096	3/4 Ton Cab-n-Chassis w/Util. Bed 4wd ext Cab (2)				68,780						
5101601	2750.10		31112	REPLACEMENT FOR SURVEY VEHICLE 31112	Sell			57,922						
5101601	2750.10		31130	GMC 1/4 TON PICK-UP TRUCK				24,230						
5101701	2750.10		31115/31116/NEW	INTERNATIONAL V&H TRUCKS 7400 4X2 (3)				439,158						
5101701	2750.10		New	Freightliner Dump Truck				138,378						
5101701	2750.10		New	Escape SUV				22,507						
5101801	2750.10		31134	GMC Canyon				28,961						
5102101	2750.10		31082	CHEVROLET 1/4 TON PICK-UP TRUCK				22,161						
5102601	2750.10		31128	GMC 3/4 Ton Pick-up Truck				29,637						
5102601	2750.10		New	GMC 1 Ton Pick-up Truck				36,515						
5102801	2750.10		36960	GMC 1/4 TON PICK-UP TRUCK				28,961						

WATER UTILITY CAPITAL PURCHASES BUDGET
Five Year Projected Budget FY2020-2024

COST CENTER	OBJECT CODE	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	Comments	CRITICALITY RATING	CONDITION RATING	PAST YEAR BUDGET 2018-19	BUDGET YEAR 2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
5101301	2750.10			CHEV OR SIMILAR MID-SIZED 4X4 PICK UP W/	Jason				30,000					
5101301	2750.10			CHEV OR SIMILAR MID-SIZED 4X4 PICK UP W/	Jason				30,000					
5102601	2750.10		31128	4X4 1/2 TON VXU W/CAMPER SHELL					27,000					
5102601	2750.10		31146	1/4 TON					25,000					
5102601	2750.10		36950	1 TON NON-DUMPING FLAT BED					37,000					
5102601	2750.10		31204	CHEVY COLORADO 4WD					29,500					
5100901	2750.10		31281	FORD F-150 4WD	Marian				35,000					
5101801	2750.10		31134	COLORADO 4WD	Marian				30,000					
5101801	2750.10		31177	CHEVY COLORADO 4WD	Marian				30,000					
5100701	2750.10		NEW	1/4 TON 4WD, EXTENDED CAB, POWER WIND	Marian				30,000					
5100601	2750.10		NEW	1/4 TON 4WD, EXTENDED CAB, POWER WIND	Marian				30,000					
5100601	2750.10		NEW	1/4 ton, 4-wheel Drive, extended cab, power wind	Marian				40,000					
5100101	2750.10		31087	Replace Ford F250, State contract	Randy				41,500					
5100101	2750.10		3703	John Deere 5100M W/Mower	Randy				79,265					
5102301	2750.10			VARIOUS						1,000,000	1,000,000	1,000,000	1,000,000	
								1,349,084	494,265	1,000,000	1,000,000	1,000,000	1,000,000	-
	2750.30			**FIELD MAINT EQUIPMENT - MOTIVE**										
5100101	2750.30			Link Belt 160 x 4 Excavator				180,000						
5100101	2750.30			S550 Slide in Ass'y (Masport H XL3 Direct Drive) Alum				11,161						
5101701	2750.30			Case Backhoe				92,616						
5101701	2750.30			BACKHOE EXCHANGE PROGRAM				81,000						
5101701	2750.30			Backhoe Trailer				28,375						
5102101	2750.30			Hyster Fork Lift				43,981						
5102201	2750.30			Interstate 50tdc Trailer				28,375						
5102301	2750.30			VARIOUS				95,500		50,000	50,000	50000	50000	
5102601	2750.30			HANDHELD READING UNITS (2)	Audree				17,232					
5101601	2750.30		31148	CHEVY/GMC 4X4 EXT CAP	Nick				30,000					
5101601	2750.30		31149	CHEVY/GMC 4X4 EXT CAP	Nick				30,000					
5101601	2750.30		31150	CHEVY/GMC 4X4 EXT CAP	Nick				30,000					
5101401	2750.30		80564	SKAGG SVRII-36A-19FX	Jason/Randy				9,550					
5100101	2750.30		NEW	CAT/WHEELER BUCKET - DC 60" DITCH	Jason/Randy				5,400					
5101601	2750.30			KUBOTA BX235 Mini-Tractor	Marian				25,000					
5101601	2750.30			Winter Tractor	Marian				28,000					
								561,008	175,182	50,000	50,000	50,000	50,000	-
	2760.10			**PUMP PLANT EQUIPMENT**										
5100801	2760.10			CLEAR WATER AND AREA DRAIN PUMPS				40,000						
5100801	2760.10			REPLACE EXISTING LMI CHEMICAL FEED PUMPS				9,537						

WATER UTILITY CAPITAL PURCHASES BUDGET
Five Year Projected Budget FY2020-2024

COST CENTER	OBJECT CODE	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	Comments	CRITICALITY RATING	CONDITION RATING	PAST YEAR BUDGET 2018-19	BUDGET YEAR 2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
5100801	2760.10			REPLACE VALVING MAINFOLD IN PUMP HOUSE				100,000						
5100901	2760.10			EQUALIZATION PUMP				19,455						
5100901	2760.10			WASTEWATER RETURN PUMP				13,492						
5101301	2760.10			VARIOUS				50,000	50,000	50,000	50,000	50,000	50,000	
								232,484	50,000	50,000	50,000	50,000	50,000	-
	2760.20			**TREATMENT PLANT EQUIPMENT**										
5100701	2760.20			FLOC BUSHING		4	4	30,000						
5100701	2760.20	5122631		SECURITY FENCE FOR SLUDGE BEDS/BACKWASH TANK		3	3	75,000						
5100701	2760.20	5122632		SECURITY FENCING FOR BACK OF PLANT		3	3	40,000						
5100701	2760.20			REPLACEMENT PARTICLE COUNTERS				24,000						
5100701	2760.20			TURBIDITY METERS				35,000						
5100701	2760.20			ON-DEMAND HOT WATER HEATERS										
5100801	2760.20			DR 6000-PHOTANALYZER (UV BULB)				8,000						
5100801	2760.20			CHLORINE ANALYZER				8,000						
5100801	2760.20			HEADLOSS METER				13,300						
5100801	2760.20	18		BACK-UP WATER SUPPLY FROM CLEARWELL TO HIGH PRESSURE TANK										
5100801	2760.20	5124508		PARLEY'S TP - REPLACE ALL POST STORAGE TANK HYP(		1	1							
5100801	2760.20			DR 6000-PHOTOANALYZER (UV BULB)				8,000						
5100801	2760.20			CHLORINE ANALYZER				8,000						
5100801	2760.20			HEADLOSS METER				13,300						
5100801	2760.20			FLYGT 4" SUBMERSIBLE PUMP MODEL CP3102.090				13,910						
5100901	2760.20			HYDROMATIC SUBMERSIBLE SOLIDS HANDLING PUMP				13,910						
5100901	2760.20			FLOC BUSHING		4	4	30,000						
5100901	2760.20			CAMERA UPGRADE BIG COTTONWOOD										
5100901	2760.20			ONLINE TURBIDITY METER				70,000						
5101301	2760.20			VARIOUS				100,000		100,000	100,000	100000	100000	
5100801	2760.20			SURFACE WASH PUMP	Marian				60,000					
								490,420	60,000	100,000	100,000	100,000	100,000	-
	2760.30			**TELEMETRY EQUIPMENT**										
5101501	2760.30			MISCELLANEOUS WATER TELEMETRY 2018/2019				50,000	50,000	50,000	50,000	50,000	50,000	
5101501	2760.30			Telemetry Equipment - Water Ongoing				50,000						
5101501	2760.30			CCTV Recorder - Dispatch				10,000						
5101501	2760.30		2017-1308	INSTALLATION OF NEW SNOW GAUGING STATIONS		4	0	60,000						
5100201	2760.30			TELEMETRY FOR TWIN LAKES										
								170,000	50,000	50,000	50,000	50,000	50,000	-
	2760.50			**OFFICE FURNITURE & EQUIPMENT**										
5103201	2760.50			SOFTWARE UPGRADE BILLING SYSTEM				30,000	30,000	30,000	30,000	30000	30000	
5101301	2760.50			Full Function Printer replacement "Engineering"				5,765						
5103301	2760.50			Full Function Printer replacement "Contracts"				5,765						
	2760.90			**OTHER NON-MOTIVE EQUIPMENT**				41,530	30,000	30,000	30,000	30,000	30,000	-

WATER UTILITY CAPITAL PURCHASES BUDGET
Five Year Projected Budget FY2020-2024

COST CENTER	OBJECT CODE	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	Comments	CRITICALITY RATING	CONDITION RATING	PAST YEAR BUDGET 2018-19	BUDGET YEAR 2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
5103201	2760.90			VARIOUS				50,000	50,000	50,000	50,000	50,000	50,000	
5101701	2760.90			EMERGENCY PIPING				50,000	50,000	50,000	50,000	50,000	50,000	
5102601	2760.90			HANDHELD METER READING DEVICES				20,000	20,000	20,000	20,000	20,000	20,000	
5100601	2760.90			WOOD CHIPPER				79,010						
5100601	2760.90			NEW 2018 MCLAUGHLIN VSK 25-100G VACUUM				18,965						
5101201	2760.90			TRAILER FOR SPILL RESPONSE AT DIVERSION				6,000						
5101201	2760.90			BOAT				5,000						
								228,975	120,000	120,000	120,000	120,000	120,000	-
				TOTAL CAPITAL OUTLAY				$ 4,898,838	$ 2,509,447	$2,930,000	$2,930,000	$2,930,000	$2,930,000	$1,500,000

Sewer Utility- Budget Summary and Cash Flow

SEWER UTILITY
ENTERPRISE FUND
BUDGET SUMMARY
FY 2020-22

SOURCES	ACTUAL 2017-18	AMENDED BUDGET 2018-19	PROJECTED ACTUAL 2018-19	Rate Increase 18% PROPOSED BUDGET 2019-20	Rate Increase 18% FORECAST BUDGET 2020-21	Rate Increase 18% FORECAST BUDGET 2021-22
REVENUES						
METERED SALES	$ 33,620,751	$ 37,677,666	$ 37,677,666	**$ 44,460,000**	$ 52,838,000	$ 62,791,000
INTEREST INCOME	1,579,221	1,052,000	$ 1,052,000	**604,000**	23,000	29,000
OTHER REVENUES	659,888	235,000	$ 235,000	**235,000**	235,000	235,000
TOTAL REVENUES	$ 35,859,860	$ 38,964,666	$ 38,964,666	**$ 45,299,000**	$ 53,096,000	$ 63,055,000
OTHER SOURCES						
IMPACT FEES	971,344	700,000	$ 700,000	**700,000**	724,500	749,858
GRANTS & OTHER RELATED REVENUES	978,525	2,020,000	$ 2,020,000	**2,020,000**	2,020,000	720,000
OTHER SOURCES	2,845	20,000	$ 20,000	**20,000**	20,000	20,000
STATE LOAN (NWQ)	-	-	$ -	**-**	-	-
NON BOND FINANCING	8,500,000	4,000,000	$ -	**-**	67,429,000	85,926,000
BOND PROCEEDS	-	-	$ -	**55,307,000**	39,218,000	97,542,000
T O T A L OTHER SOURCES	$ 10,452,714	$ 6,740,000	$ 2,740,000	**$ 58,047,000**	$ 109,411,500	$ 184,957,858
T O T A L SOURCES	$ 46,312,574	$ 45,704,666	$ 41,704,666	**$ 103,346,000**	$ 162,507,500	$ 248,012,858
EXPENSES & OTHER USES						
EXPENDITURES						
PERSONNEL SERVICES	$ 8,486,161	$ 10,375,345	$ 10,375,345	**$ 11,164,232**	$ 11,610,802	$ 12,075,232
OPERATING & MAINTENANCE	1,406,164	1,934,720	1,934,720	**2,109,430**	2,151,219	2,194,242
TRAVEL & TRAINING	48,179	86,900	86,900	**118,425**	120,794	123,209
UTILITIES	852,935	980,070	980,070	**994,970**	1,014,869	1,035,166
TECHNICAL SERVICES	1,831,306	3,291,348	3,291,348	**3,151,533**	3,327,843	3,394,400
DATA PROCESSING	381,234	280,000	280,000	**395,000**	402,900	410,958
FLEET MAINTENANCE	568,447	543,000	543,000	**543,000**	553,860	564,937
ADMINISTRATIVE SERVICE FEE	306,260	275,000	275,000	**311,000**	317,220	323,564
PAYMENT IN LIEU OF TAXES	306,525	368,250	368,250	**661,263**	674,488	687,978
BILLING COST	813,896	813,896	813,896	**827,634**	844,187	861,071
RISK MANAGEMENT	303,564	308,500	308,500	**260,324**	265,530	270,841
TRANSFERS TO GENERAL FUND	-	20,000	20,000	**-**	-	-
OTHER CHARGES AND SERVICES	50,100	148,588	148,588	**487,353**	496,676	506,611
TOTAL EXPENDITURES	$ 15,354,771	$ 19,425,617	$ 19,425,617	**$ 21,024,164**	$ 21,780,388	$ 22,448,209
OTHER USES						
CAPITAL OUTLAY	847,714	5,946,500	1,302,569	**8,694,000**	823,000	823,000
CAPITAL IMPROVEMENT BUDGET	33,243,806	116,640,041	60,892,051	**98,370,500**	125,728,000	210,160,000
COST OF DEBT ISSUANCE	7,200	15,000	-	**307,000**	218,000	542,000
DEBT SERVICES	5,554,277	6,058,000	6,050,603	**13,149,000**	13,399,000	13,776,000
T O T A L OTHER USES	$ 39,652,997	$ 128,659,541	$ 68,245,223	**$ 120,520,500**	$ 140,168,000	$ 225,301,000
T O T A L USES	$ 55,007,768	$ 148,085,158	$ 87,670,840	**$ 141,544,664**	$ 161,948,388	$ 247,749,209
EXCESS REVENUE AND OTHER SOURCES OVER (UNDER) USES	$ (8,695,194)	$ (102,380,492)	$ (45,966,174)	**$ (38,198,664)**	$ 559,112	$ 263,649
OPERATING CASH BALANCES						
BEGINNING JULY 1	$ 94,916,245	$ 86,221,051	$ 86,221,051	**$ 40,254,877**	$ 2,056,213	$ 2,615,325
ENDING JUNE 30	$ 86,221,051	$ (16,159,441)	$ 40,254,877	**$ 2,056,213**	$ 2,615,325	$ 2,878,974
Cash Reserve Ratio	562%	-83%	207%	**10%**	12%	13%

Cash reserve goal above 10%

SEWER UTILITY
Cash Flow
FY20 Budget
and FY2020-2024 Forecast

+18%,18%,18%,15%,10% rates
$259M in WIFIA Funds
$283M in Bonds,$55M,$39M,$97M,$65M $27M
100% CIP FY 20-24
New Debt Pmts $44.9M FY 20-24

	ACTUAL YEAR 2017-2018	PROJECTED YEAR 2018-2019	BUDGET YEAR 2019-2020	BUDGET YEAR 2020-2021	BUDGET YEAR 2021-2022	BUDGET YEAR 2022-2023	BUDGET YEAR 2023-24
SEWER SALES	$33,620,751	$37,677,666	$44,460,000	$52,838,000	$62,791,000	$72,718,000	$80,548,000
OTHER INCOME	662,733	255,000	255,000	255,000	255,000	255,000	255,000
INTEREST INCOME	1,579,221	1,052,000	604,000	23,000	29,000	31,000	30,000
OPERATING INCOME	35,862,705	38,984,666	45,319,000	53,116,000	63,075,000	73,004,000	80,833,000
NEW PLANT O&M COSTS			0	0		*(250,000)*	*(252,500)*
OPERATING EXPENSES	(15,354,771)	(19,425,617)	(21,024,164)	(21,780,388)	(22,448,209)	(23,138,679)	(23,852,612)
NET INCOME EXCLUDING DEP.	20,507,934	19,559,049	24,294,836	31,335,612	40,626,791	49,615,321	56,727,888
IMPACT FEES	971,344	700,000	700,000	724,500	749,858	776,103	803,267
STATE LOAN (NWQ)	8,500,000						
SHORT TERM FINANCING PROCEEDS							
WIFIA LOAN				67,429,000	85,926,000	65,057,000	31,865,000
NET BOND PROCEEDS	-		55,000,000	39,000,000	97,000,000	65,000,000	27,000,000
ISSUE COSTS (PROCEEDS)			307,000	218,000	542,000	363,000	151,000
ISSUE COSTS (EXP)	(7,200)		(307,000)	(218,000)	(542,000)	(363,000)	(151,000)
OTHER CONTRIBUTIONS	978,525	2,020,000	2,020,000	2,020,000	720,000	520,000	520,000
CAPITAL OUTLAY	(847,714)	(1,302,569)	(8,694,000)	(823,000)	(823,000)	(823,000)	(823,000)
STATE LOAN DEBT REPAYMENT			(6,375,000)	(2,125,000)			
NEW DEBT SERVICE			(719,000)	(2,700,000)	(5,216,000)	(9,091,000)	(12,731,000)
DEBT SERVICE	(5,554,277)	(6,050,603)	(6,055,000)	(8,574,000)	(8,560,000)	(8,561,000)	(8,935,850)
OTHER INCOME & EXPENSE	4,040,678	(4,633,172)	35,877,000	94,951,500	169,796,858	112,878,103	37,698,417
GENERATED FOR CAPITAL	24,548,612	14,925,877	60,171,836	126,287,112	210,423,649	162,493,424	94,426,305
CAPITAL IMPROVEMENTS	(33,243,806)	(60,892,051)	(98,370,500)	(125,728,000)	(210,160,000)	(162,630,000)	(94,660,000)
CASH INCREASE/(DECREASE)	(8,695,194)	(45,966,174)	(38,198,664)	559,112	263,649	(136,576)	(233,695)
		0					
BEGINING CASH BALANCE	94,916,245	86,221,051	40,254,877	2,056,213	2,615,325	2,878,974	2,742,398
CASH INCREASE/(DECREASE)	(8,695,194)	(45,966,174)	(38,198,664)	559,112	263,649	(136,576)	(233,695)
ENDING BALANCES	86,221,051.00	40,254,877.00	2,056,213	$2,615,325	$2,878,974	$2,742,398	$2,508,703
RESTRICTED/RESERVED	(10,789,378)						
AVAILABLE ENDING BALANCE	$75,431,673	$40,254,877	2,056,213	$2,615,325	$2,878,974	$2,742,398	$2,508,703
RATE CHANGE	30%	15%	18%	18%	18%	15%	10%
Cash Reserve Ratio	**562%**	**207%**	**10%**	**12%**	**13%**	**12%**	**10%**
Debt Service Coverage	**3.69**	**3.23**	**3.59**	**2.78**	**2.95**	**2.81**	**2.62**
DEBT SERVICE % OF GROSS OPERATING REV	**15%**	**16%**	**15%**	**21%**	**22%**	**24%**	**27%**
MONTHLY RESIDENTIAL UTILITY BILL AT 4 CC	**10.60**	**12.16**	**14.68**	**17.32**	**20.44**	**23.51**	**25.86**
MONTHLY RESIDENTIAL UTILITY BILL AT 8 CC	**21.20**	**24.32**	**29.36**	**34.64**	**40.88**	**47.01**	**51.71**

SEWER UTILITY CIP BUDGET
Five Year Projected Budget FY2020-2024

COST CENTER	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	CRITICALITY RATING	CONDITION RATING	PAST YEAR SPENT 2018-19 (Calc'd from P6)	BUDGET YEAR 2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
	2720.10		**MAINTENANCE & REPAIR SHOPS - 2720.10**									
		2016-0956	LIFT STATION STORAGE FACILITY	4	0	0			350,000			
						0	0	0	350,000	0	0	0
	2720.05		**LIFT STATIONS - 2720.05**									
			LIFT STATION ASSET MANAGEMENT PROGRAM									
10101	524907096		ANNUAL SYSTEM WIDE LIFT STATION SCOPING & ASSET MANAGEMENT PRIORITIZATION	5	5	200,000	200,000	200,000	80,000	80,000	80,000	320,000
			LIFT STATION RENEWAL/REPLACEMENT PROGRAM									
	52490788		LIFT STATION CONDITION ASSESSMENT (TASK ORDER 2.18)			10,938						
10101	524907095	2015-0414	ANNUAL PUMP REPLACEMENT (VARIOUS)	5	5	25,000	25,000	25,000	50,000	50,000	50,000	200,000
	52490758	2015-0266	4000 WEST LIFT STATION UPGRADE/REPLACEMENT (SS12)	5	5	911,983						
10101	52490780	2015-0263	1700 NORTH LIFT STATION REHABILITATION (SS03)	4	5	299,998						
10101		2017-1301	5300 WEST LIFT STATION (SS17) CAPACITY IMPROVEMENTS	4	5	0	75,000	430,000				
10101	52490778	2015-0264	SOUTH LIFT STATION (SS05)	3	4	0			65,000	365,000		
10101		2015-0417	INDUSTRIAL LIFT STATION REHAB & PIPING UPGRADES (SS21)	4	5	0	70,000	710,000				
10101		2015-0267	NEW ROSE PARK LIFT STATION REPLACEMENT (SS02)	4	5	0	40,000	320,000				
10101	2015-0268	2015-0268	500 W LIFT STATION WET WELL IMPROVEMENTS (SS28)	4	5	0	50,000	425,000				
10101		2015-0274	PIONEER LIFT STATION WET WELL IMPROVEMENTS (SS20)	4	4	0			60,000	570,000		
10101		2015-0418	CENTENNIAL LIFT STATION WET WELL REHABILITATION (SS 19)	4	4	0			70,000	650,000		
10101		2015-0271	CANNON LIFT STATION WET WELL IMPROVEMENTS	4	4	0			40,000	375,000		
10101		2015-0270	WESTPOINTE LIFT STATION WET WELL IMPROVEMENTS (SS 33)	3	3	0						550,000
10101		2015-0272	900 NORTH LIFT STATION WET WELL IMPROVEMENTS	4	5	0	50,000	450,000				
		2017-2008	BILLY MITCHELL (SS16) CAPACITY IMPROVEMENTS	3	4	0			60,000	750,000		
	524907093	2017-2075	HUSKY LIFT STATION		4	2,600,000						
						4,047,918	510,000	2,560,000	425,000	2,840,000	130,000	1,070,000
	2720.30		**TREATMENT PLANTS**									
11201	524905347	2015-0640	FACILITY BUILDING PAINTING (CORROSION PROTECTION PROGRAM)	5	5	100,000	100,000	100,000	100,000	100,000	100,000	400,000
	524905338	2017-2093	INFLUENT SCREEN (S) REPLACE/RETROFIT	5	5	712,728	3,200,000					
	524905336		EXISTING FACILITES CONDITION ASSESSMENT/PRE-DESIGN		5	75,000						
	525400075		SOUTH RAS SKIMMER RELOCATION		4	14,615						
	52540066		WETLANDS RESTORATION PROJECT		4	0						
	524905342		PROCESS CONTROL LAB ROOM		4	19,221						
		2016-1275	WASHER COMPACTOR FOR PRIMARY SLUDGE	4	0	0		250,000				
	525400074	2017-2088	SCADA INSTRUMENTATION CONTROL IMPROVEMENTS	5	5	0						
~~11201~~	524905330	2015-0707	CHLORINE BUILDING ALARM SYSTEM		5	210,000						
		2018-1074	SCADA PHASE III FOLLOW-UP SERVICES	5	5	0	400,000					
~~11201~~	524905280	2015-0710	REPLACEMENT OF MCC2A AT THE PRE-SEDIMENTATION BUILDING - CONSTRUCTION		5	575,531						
11201	52540053	2015-0708	ATMOSPHERIC MONITORING REPLACEMENT PROGRAM	5	5	19,537		25,000	25,000	25,000	25,000	100,000
	52540064		VFD REPLACEMENT		5	227,208						
11201	52540052	2015-0500	TRICKLING FILTER REHABILITATION	5	5	0	650,000					2,000,000

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COST CENTER	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	CRITICALITY RATING	CONDITION RATING	PAST YEAR SPENT 2018-19 (Calc'd from P6)	BUDGET YEAR 2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
	52540067		TRICKLIKNG FILTER PUMPS INSPECTION & RECONDITIONING			117,229						
11201	524905345	2015-0502	CAPITAL ASSET REHABILITATION AND UPGRADES	5	5	1,300,000	1,300,000	1,300,000	1,300,000	1,300,000	1,300,000	5,200,000
11201	2016-1133	2016-1133	REHAB OF VERTICAL TURBINE PUMPS	4	4	0				200,000		400,000
11201	524905344	2017-2089	HVAC REPLACEMENTS	3	3	25,000		25,000	25,000	25,000	25,000	100,000
	524905341		HVAC IMPROVEMENTS AT PRE-SEDIMENTATION			6,938						
		2016-1281	COGEN ENGINE OVERHAUL									700,000
		2018-1052	SLC WRF HEADWORKS GATE REPLACEMENT	5	5	0	250,000					
	524905334	2016-1160	UPGRADE EMERGENCY GENERATORS AT PUMP STATION	4	5	0	50,000					
		2018-1072	SLC WRF INFLUENT PUMP MOTOR REBUILD	5	4	0	120,000					
		2018-1071	SLC WRF INFLUENT PUMP REBUILD	5	4	0	200,000					
		2018-1068	SLC WRF BIO GAS HEAT EXCHANGER	4	4	0	75,000					
		2018-1066	SLC WRF PUMP PLANT EXTERIOR LIGHTING	4	5	0	35,000					
			NEW WATER RECLAMATION FACILITY									
	524905271		NEW PLANT - CORE DESIGN/BUILD RECLAMATION FACILITY	5	0	0	1,750,000	10,250,000	5,000,000	3,500,000	2,000,000	400,000
	524905335		WRF MASTER PLAN IMPLEMENTATION - CAPITAL PROJECT SUPPORT	5	0	1,500,000	4,500,000	4,500,000	4,500,000	3,500,000	3,500,000	4,000,000
11201	524905271		NEW PLANT - MECHANICAL DEWATERING (CONSTRUCTION)	5	0	0	33,500,000	440,000				
			NEW PLANT - BNR LIQUID STREAM (CONSTRUCTION)	5	0	0		41,020,000	#########	120,360,000	15,960,000	
			NEW PLANT - SOLIDS HANDLING (CONSTRUCTION)	5	0	0					41,160,000	2,840,000
			NEW PLANT - ADMIN OPS (CONSTRUCTION)	5	0	0		14,090,000	1,620,000			
			NEW PLANT - DEMOLITION (CONSTRUCTION)	5	0	0						6,500,000
	525400068	2017-2050	NEW PLANT - PROFESSIONAL DESIGN SERVICES	5	0	12,459,510	9,500,000	7,800,000	7,500,000	5,100,000	2,100,000	3,000,000
	524905339	2017-2051	NEW PLANT - CM/GC DESIGN SERVICES	5	0	488	3,000,000	2,500,000	1,000,000			
	524905337	2017-2052	NEW PLANT - WATER RENEW PUBLIC OUTREACH	5	0	250,000	300,000	250,000	250,000	250,000	250,000	500,000
	524905340	2017-2054	NEW PLANT - PILOTING AND DEMONSTRATION TESTING	5	0	98,947	2,000,000	2,000,000				
			NEW PLANT - PROJECT DOCUMENTATION	4	0	0	150,000	60,000	60,000	60,000	60,000	120,000
11201	524905272	2015-0404	NEW WATER RECLAMATION FACILITY - INFLUENT SCREENINGS (CONSTRUCTION)		5	0						
			TOTAL NEW WATER RECLAMATION FACILITY				54,700,000	82,910,000	#########	132,770,000	65,030,000	17,360,000
			TOTAL WATER RECLAMATION FACILITY			17,711,954	61,080,000	84,610,000	176,810,000	134,420,000	66,480,000	26,260,000
	2730.14		**COLLECTION LINES**									
			COLLECTION SYSTEM ASSET MANAGEMENT PROGRAM									
10401	52510020	2015-0704	1200 WEST TRUNK LINE CONDITION ASSESSMENT/ PROJECT PRE-DESIGN	5	2	0						600,000
10401	525002742	2015-0664	SIPHON INSPECTION PROJECT	4	2	0					100,000	
10401	525002834	2015-0647	COLLECTION SYSTEM PROJECT DEVELOPMENT CAP SCOPING	5	5	100,000	150,000	150,000	100,000	100,000	100,000	400,000
10401	525002770	2015-0703	BECK STREET TRUNK LINE CONDITION ASSESSMENT/PRE-DESIGN	5	2	232,403						600,000
10401	525002771	2015-0705	ORANGE STREET TRUNK LINE CONDITION ASSESSMENT/PROJECT PRE-DESIGN	5	2	0						500,000
						332,403	150,000	150,000	100,000	100,000	200,000	2,100,000
			FLOW MONITORING/I&I PROGRAM									
10401	525002756	2015-0648	WEST SIDE INFLOW & INFILTRATION STUDY		5	151,004						
10401	525002741	2015-0651	ANNUAL HYDRAULIC MODEL CALIBRATION	4	2	0				100,000		300,000

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COST CENTER	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	CRITICALITY RATING	CONDITION RATING	PAST YEAR SPENT 2018-19 (Calc'd from P6)	BUDGET YEAR 2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
10401	525002740	2015-0649	PERMANENT FLOW METERS	5	0	350,000		250,000	250,000	250,000		
			VARIOUS BASIN INFLOW TESTING		4	0						
						501,004	0	250,000	250,000	350,000	0	300,000
			CITY, COUNTY, STATE AND MISC. DRIVEN PROJECTS									
10401	525002738	2015-0654	PRISON RELOCATION UTILITIES AND DEVELOPMENT SUPPORT		5	330,263						
	525002674		TERMINAL REDEVELOPMENT PROJECT	5	0		5,000	5,000				
10401	525002560	2015-0484	ANNUAL MISC. PUBLIC SERVICES PROJECTS	5	5	200,000	200,000	200,000	200,000	200,000	200,000	1,000,000
10401	525002738	2016-1262	NW QUADRANT CF INFRASTRUCTURE SUPPORT SERVICES	5	5	330,263	400,000	350,000				
	525002760		WEST TEMPLE - NORTH TEMPLE TO 400 SOUTH	4	5	673,778						
10401	525002764	2016-0743	1300 EAST - SEWER		5	285,900						
10401	2016-1265	2016-1265	NW QUADRANT (DEVELOPMENT) PIPE UPSIZE SEWER	5	0	0	350,000					
10401	525002681		WILMINGTON AVENUE SANITARY SEWER			15,082						
10401			MOUNTAIN VIEW CORRIDOR UDOT BETTERMENT			0	250,000					
			ODOR & CORROSION PRELIMINARY DESIGN AND SITING ANALYSIS	5	5	0	350,000					
			ODOR & CORROSION IMPLEMENTATION PROGRAM	5	0	0	50,000	1,500,000	1,500,000	1,500,000	1,500,000	4,500,000
			900 S (950 E TO 1300 E) ROADWAY	5	5	0	600,000					
			1900 EAST - WILMINGTON TO PARLEYS CANYON	5	5	0	450,000					
			700 W (1600 S TO 2100 S) ROADWAY	5	5	0	400,000					
			800 WEST 600 S to 800 S	5	5	0	250,000					
			500 EAST - 1700 SOUTH TO 2100 SOUTH	5	5	0	300,000					
			CITY WIDE STREET IMPROVEMENTS AND PRESERVATION 2019/2020	5	5	0	2,500,000					
			2000 E (PARLEYS CANYON BLVD TO CITY LIMIT) ROADWAY	5	5	0	200,000					
			300 W (900 S TO 2100 S) ROADWAY	5	5	0	150,000	2,000,000				
			900 EAST (HOLLYWOOD AVE TO 2700 S) ROADWAY	5	5	0		350,000				
			100 S (NORTH CAMPUS DRIVE TO 900 E) ROADWAY	5	5	0		500,000				
			1700 EAST (1700 S TO 2700 S) ROADWAY	5	5	0		550,000				
			CITY WIDE STREET IMPROVEMENTS AND PRESERVATION 2020/2021	5	5	0		2,500,000				
			300 WEST - 600 SOUTH to 2100 SOUTH	5	5	0			500,000			
			200 SOUTH - 400 WEST TO 900 EAST, PHASE 1	5	5	0			500,000			
			CITY WIDE STREET IMPROVEMENTS AND PRESERVATION 2021/2022	5	5	0			2,500,000			
			1100 EAST TO HIGHLAND - ROMONA AVE TO WARNOCK AVENUE	5	5	0				500,000		
			1100 EAST - 900 SOUTH TO RAMONA AVE	5	5	0				500,000		
			200 SOUTH - 400 WEST TO 900 EAST, PHASE 2	5	5	0				300,000		
			1300 EAST - 2100 SOUTH TO CITY BOUNDARY	5	5	0				500,000		
			CITY WIDE STREET IMPROVEMENTS AND PRESERVATION 2022/2023	5	5	0				2,500,000		
			VIRGINA STREET - SOUTH TEMPLE TO 11TH AVE	5	5	0					500,000	
			300 NORTH - 300 WEST TO 1000 WEST	5	5	0					500,000	
			CITY WIDE STREET IMPROVEMENTS AND PRESERVATION 2023/2024	5	5	0					2,500,000	
			900 SOUTH - 900 WEST TO 300 WEST AND WEST TEMPLE TO 900 EAST	5	5	0						1,000,000
			2100 SOUTH - 700 EAST TO 1700 EAST	5	5	0						500,000
			CITY WIDE STREET IMPROVEMENTS AND PRESERVATION 2023/2024	5	5	0						2,500,000
						1,835,286	6,455,000	7,955,000	5,200,000	6,000,000	5,200,000	9,500,000
			PIPE RENEWAL & REPLACEMENT PROGRAM									
10401	525002705	2015-0332	300 WEST - 500 NORTH TO 600 NORTH (WEST SIDE)		3	1,663						

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COST CENTER	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	CRITICALITY RATING	CONDITION RATING	PAST YEAR SPENT 2018-19 (Calc'd from P6)	BUDGET YEAR 2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
10401	525002708	2015-0333	WEST CAPITOL STREET - COLUMBUS STREET TO ZANE AVENUE TO WALL STREET		3	0						
10401	525002629	2015-0344	REDWOOD ROAD - PAXTON AVENUE TO CALIFORNIA AVENUE		3	96,755						
10401	525002780	2016-0840	4600 WEST DIVERSION I&I MITIGATION PROJECT		4	296,732						
	525002838		GLENDALE GOLF COURSE LATERAL			90,953						
10401		2015-0486	1% PER YEAR SEWER REHABILITATION/SYSTEM RENEWAL	5	5	0			2,650,000	3,000,000	3,000,000	20,000,000
	525002761	2015-0283	700 N I-15 BYPASS FOR INSPECTION OF EXISTING LINE	5	0	94,140	1,100,000					
10401	525002719	2015-0303	NORTH TEMPLE (100 N) - APPROX. 2050 WEST TO GLADIOLA STREET	5	5	150,000	2,100,000	200,000				
10401	2015-0722	2015-0722	TESORO SEWER TRUNK LINE REHABILITATION	5	4	0			250,000	6,000,000		
10401		2016-0897	WEST TEMPLE FROM TRUMAN AVE TO 1300 S CIPP	5	4	0				350,000	2,000,000	2,000,000
10401	2016-0902	2016-0902	800 S AND 1100 E LATERAL CONNECTIONS AND UPSTREAM INFILTRATION	3	4	0				20,000	150,000	
10401		2015-0727	300 W - 550 S TO 600 S	5	4	0					150,000	
10401	525002443	2016-0895	ELGIN AVE SEWER REPLACEMENT	3	3	0					400,000	
10401	2015-0318	2015-0318	700 SOUTH - 3750 WEST TO IRON ROSE PLACE (3830 W)	4	4	0					200,000	
	525002744	2016-0833	2300 EAST SEWER REHAB FROM EAST TO WEST SIDE OF FOOTHILL BLVD	5	5		60,000					
	525002774	2015-0728	ALLY BETWEEN LAKE ST AND 800 E	5	5		30,000					
	525002776	2015-0730	THIRD AVE FROM E ST TO F ST	5	5		30,000					
	525002836		OMNI AND STARCREST SEWER REHAB	5	5		50,000					
	525002858	2016-1050	CIPP SEWER ON 1675 E TOMAHAWK DR	5	5		100,000					
	525002772		WEST CAPITOL ST SANITARY SEWER MAIN FROM 490 N TO 520 N.	5	5		30,000					
10401	2016-0873	2016-0873	DOOLEY COURT	3	5	0	60,000					
	525002851	2017-2130	1200 WEST TRUNK LINE REHABILITATION PROJECT	5	5	400,106	1,000,000	4,000,000	4,000,000	4,000,000		
			BECK STREET TRUNK LINE REHABILITATION PROJECT	5	3	0					800,000	10,000,000
10401		2016-0908	3RD AVE D TO E STREET	3	5	0	140,000					
10401		2015-0731	MAIN ST - 320 N TO 340 N	4	5	0	110,000					
10401	525002355	2016-0861	6TH AVE FROM 588 E TO H ST	4	5	330,708	180,000					
10401	525002390	2016-0866	400 WEST FROM 100 NORTH TO 140 NORTH (WEST SIDE) CIPP INSTALLATION	3	4	0	40,000					
10401		2016-0989	2600 EAST AND BLAINE AVE REHABILITATION	3	5	0	150,000					
10401		2016-0991	CIPP SEWER ON FOOTHILL DR	3	5	0	110,000					
10401		2016-0992	WASATCH DR FROM 1300 SOUTH TO VILLAGE CIRCLE SEWER REHAB	3	5	0	260,000					
10401		2016-0993	FOOTHILL DR AND 1300 SOUTH SEWER REHAB	3	5	0	70,000					
10401		2016-0995	LOGAN WAY AND 1700 SOUTH SEWER REHAB	3	5	0	75,000					
10401		2016-0997	700 EAST FROM 2700 SOUTH TO CRYSTAL AVE SEWER REHAB	3	5	0	105,000					
10401		2016-0998	600 WEST 100 SOUTH SEWER REHAB	3	5	0	150,000					
10401		2016-1001	BROADMOOR ST FROM ELM AVE TO 2100 SOUTH SEWER REHAB	3	5	0	55,000					
10401		2016-1002	2300 EAST FROM STRINGHAM AVE TO BERNADINE DR SEWER REHAB	3	5	0	30,000					
10401		2016-1003	LYNWOOD DR SEWER REHAB	3	5	0	75,000					
10401		2016-1004	2300 EAST AND COUNTRY CLUB DRIVE SEWER REHAB	3	5	0	40,000					
10401		2016-1005	WILSHIRE CIRCLE SEWER REHAB	3	5	0	155,000					
10401		2016-1008	P STREET FROM 4TH AVE TO 3RD AVE SEWER REHAB	3	5	0	40,000					
10401		2016-1009	1ST AVE FROM T STREET TO U STREET SEWER REHAB	3	5	0	140,000					
10401		2016-1011	1200 EAST FROM FENWAY AVE TO 700 SOUTH SEWER REHAB	3	5	0	35,000					
10401		2016-1012	FULLER AVE FROM 1000 EAST TO 1100 EAST SEWER REHAB	3	5	0	35,000					
10401		2016-1013	500 SOUTH AND 1300 EAST SEWER REHAB	3	5	0	35,000					
10401		2016-1014	600 SOUTH 1300 EAST SEWER REHAB	3	5	0	45,000					
10401		2016-1016	1200 EAST AND 700 SOUTH SEWER REHAB	3	5	0	50,000					
10401		2016-1017	SUNNYSIDE AVE FROM CONNOR ST TO 2200 EAST SEWER REHAB	3	5	0	40,000					
10401		2016-1018	MICHIGAN AVE AND FOOTHILL BLVD SEWER REHAB	3	5	0	40,000					

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10401	525002829	2016-1019	FOOTHILL DRIVE AND 2100 EAST SEWER REHAB	3	5	0	90,000					
10401		2016-1020	LAIRD AVE SEWER REHAB	3	5	0	240,000					
10401	525002828	2016-1021	BROWNING AVE AND 1700 EAST	3	5	0	15,000					
10401	525002820	2016-1024	LOGAN AVE SEWER REHAB	3	5	0	100,000					
10401	525002800	2016-1026	1600 EAST FROM LOGAN AVE TO 1700 SOUTH SEWER REHAB	3	5	0	45,000					
10401		2016-1028	1900 EAST FROM 800 SOUTH AND 900 SOUTH SEWER REHAB	3	5	0	30,000					
10401		2016-1030	HARVARD AVE AND MCCLELLAND SEWER REHAB	3	5	0	90,000					
10401		2016-1031	BACKLOT BETWEEN PAXTON AVE AND FREMONT AVE SEWER REHAB	3	5	0	40,000					
10401		2016-1032	800 SOUTH FROM 700 EAST TO LAKE ST SEWER REHAB	3	5	0	85,000					
10401	525002804	2016-1035	2700 SOUTH AND IMPERIAL ST SEWER REHAB	3	5	0	100,000					
10401	525002809	2016-1036	JUDITH ST BETWEEN ZENNITH AVE AND HUDSON AVE SEWER REHAB	3	5	0	50,000					
10401	525002826	2016-1038	HOLLYWOOD AVE FROM 900 EAST TO LINCOLN ST SEWER REHAB	3	5	0	50,000					
10401	525002797	2016-1039	2100 SOUTH FROM 1900 EAST TO PRESTON ST SEWER REHAB	3	5	0	20,000					
10401		2016-1040	CIPP SEWER ON 800 EAST FROM SOUTH TEMPLE TO 100 SOUTH	3	5	0	10,000	100,000				
10401		2016-1041	CIPP SEWER ON 600 SOUTH FROM 500 EAST TO 600 EAST	3	5	0	5,000	50,000				
10401		2016-1042	CIPP SEWER ON 600 SOUTH 600 EAST	3	5	0	5,000	50,000				
10401		2016-1044	CIPP SEWER ON 300 WEST FROM ORCHARD PL TO 600 SOUTH	3	5	0	5,000	50,000				
10401		2016-1047	CIPP SEWER ON EMERSON AVE BETWEEN 2200 EAST AND 2300 EAST	3	5	0	6,500	65,000				
10401		2016-1048	CIPP SEWER ON ROOSEVELT AVE AND 2200 EAST	3	5	0	3,000	30,000				
10401		2016-1058	CIPP SEWER ON DARWIN ST FROM GIRARD AVE TO ZANE AVE	3	5	0	5,000	50,000				
10401		2016-1059	CIPP SEWER ON 1040 SOUTH BONNEVILLE DR	3	5	0	5,000	50,000				
10401		2016-1077	CIPP SEWER ON 1100 EAST BETWEEN 100 SOUTH AND 200 SOUTH	3	5	0	6,000	60,000				
10401		2016-1078	CIPP SEWER ON 200 SOUTH BETWEEN 900 EAST AND 1000 EAST	3	5	0	6,000	60,000				
10401		2016-1081	CIPP SEWER ON 1000 EAST BETWEEN 200 SOUTH AND 300 SOUTH	3	5	0	4,000	40,000				
10401		2016-1089	CIPP SEWER ALLEY WEST OF 600 E BETWEEN 800 SOUTH AND 900 SOUTH	3	5	0	20,000	200,000				
10401		2016-1090	CIPP SEWER ON GRACE CT AND WILLIAMS AVE	3	5	0	3,000	36,000				
10401		2016-1091	CIPP SEWER ON ALLEY EAST OF 300 EAST BETWEEN 800 SOUTH AND 900 SOUTH	3	5	0	3,000	36,000				
10401		2016-1093	CIPP SEWER ON 1700 EAST AND PARLEYS CANYON BLVD	3	5	0	3,000	36,000				
10401		2016-1094	CIPP SEWER ON FOURTH AVE FROM A STREET TO B STREET	3	5	0	3,000	36,000				
10401		2016-1096	CIPP SEWER ON THIRD AVE FROM E STREET TO F STREET	3	5	0	8,000	85,000				
10401		2016-1097	CIPP SEWER ON J STREET BETWEEN THIRD AVE AND FOURTH AVE	3	5	0	17,000	170,000				
10401		2016-1098	CIPP SEWER ON SECOND AVE BETWEEN F STREET AND G STREET	3	5	0	15,000	150,000				
10401		2016-1099	D STREET FROM FIRST AVE TO SECOND AVE SEWER REHAB	3	5	0	60,000					
10401		2016-1102	CIPP SEWER ON K STREET FROM SOUTH TEMPLE TO FIRST AVE	3	5	0	7,000	70,000				
10401		2016-1100	CIPP SEWER ON E STREET BETWEEN FIRST AVE AND SECOND AVE	3	5	0	4,000	40,000				
10401		2016-1103	CIPP SEWER ON 500 EAST BETWEEN SOUTH TEMPLE AND 100 SOUTH	3	5	0	10,000	105,000				
10401		2016-1104	CIPP SEWER ON SLADE PL AND 500 EAST	3	5	0	3,000	32,000				
10401		2016-1105	CIPP SEWER ON 300 SOUTH AND 300 EAST	3	5	0	65,000	642,000				
10401		2016-1110	CIPP ON A STREET BETWEEN SOUTH TEMPLE AND FIRST AVE	3	5	0	6,000	65,000				
10401		2016-1112	CIPP SEWER ON 200 EAST BETWEEN 200 SOUTH AND 300 SOUTH	3	5	0	6,000	60,000				
10401		2016-1113	CIPP SEWER ON 200 EAST BETWEEN 300 SOUTH AND 400 SOUTH	3	5	0	20,000	200,000				
10401		2016-1114	CIPP SEWER ON 200 WEST FROM 200 NORTH TO 300 NORTH	3	5	0	5,000	15,000				
10401		2016-1116	CIPP SEWER ON WEST TEMPLE BETWEEN 200 SOUTH AND 300 SOUTH	3	5	0	6,000	60,000				
10401		2016-1117	CIPP SEWER ON 200 SOUTH BETWEEN REGENT ST AND STATE ST	3	5	0	9,000	90,000				
10401		2016-1118	CIPP SEWER ON 200 SOUTH BETWEEN WEST TEMPLE AND MAIN ST	3	5	0	4,000	40,000				
10401		2016-1119	CIPP SEWER ON 400 SOUTH BETWEEN WEST TEMPLE AND MAIN ST	3	5	0	7,000	70,000				
10401		2016-1120	CIPP SEWER ON 400 SOUTH BETWEEN MAIN ST AND CACTUS ST	3	5	0	5,000	50,000				

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10401		2016-1121	CIPP SEWER ON MENLO AVE AND 800 EAST	3	5	0	6,000	60,000				17,000
10401		2016-1087	1700 SOUTH AND 1700 EAST SEWER REHAB	3	4	0			75,000			
10401		2016-1088	CIPP SEWER ON FAYETTE AVE AND WEST TEMPLE	3	4	0						17,000
10401		2016-1010	CIPP SEWER ON 1000 EAST FROM SOUTH TEMPLE TO 100 SOUTH	3	4	0						19,000
10401		2016-1101	CIPP SEWER ON B STREET BETWEEN SOUTH TEMPLE AND FIRST AVE	3	4	0						12,000
10401		2016-1109	CIPP SEWER ON ELY PL AND 700 EAST	3	4	0						20,000
10401		2016-1111	CIPP SEWER ON 200 EAST FROM 250 SOUTH TO 300 SOUTH	3	4	0						16,000
10401		2016-1115	CIPP SEWER ON 200 NORTH BETWEEN WEST TEMPLE AND ALMOND ST	3	4	0						11,000
10401		2016-1122	CIPP SEWER ON EDGEHILL ROAD AND LITTLE VALLEY ROAD	3	4	0						16,000
10401		2016-1123	CIPP SEWER ON 700 EAST EIGHTEENTH AVE	3	4	0						17,000
10401		2016-1124	CIPP SEWER ON NORTHMONT WAY AND EIGHTEENTH AVE	3	4	0						23,000
10401		2016-1126	CIPP SEWER ON TERRACE HILLS DR BETWEEN NORTHCREST DR AND NORTH BONNEVILLE	3	4	0						18,000
10401		2016-1129	CIPP SEWER ON H STREET BETWEEN ELEVENTH AVE AND TWELFTH AVE	3	4	0						13,000
10401		2016-1131	CIPP SEWER ON H STREET BETWEEN TENTH AVE AND ELEVENTH AVE	3	4	0						25,000
10401		2016-1132	CIPP SEWER ON NINTH AVE BETWEEN K STREET AND L STREET	3	4	0						21,000
10401		2016-1140	CIPP SEWER ON DORCHESTER DR FROM BRAEWICK RD TO SANDRUN RD	3	4	0						13,000
10401		2016-1142	CIPP SEWER ON B STREET FROM SIXTH AVE TO SEVENTH AVE	3	4	0						26,000
10401		2016-1144	CIPP SEWER ON 600 WEST FROM 400 NORTH TO 350 NORTH	3	4	0						21,000
10401		2016-1145	CIPP SEWER ON DONNER WAY FROM THACKERAY PL TO SHAKESPEARE PL	3	4	0						20,000
10401		2016-1152	CIPP SEWER ON KENSINGTON AVE AND BEACON DR	3	4	0						12,000
10401		2016-1153	CIPP SEWER ON CANTERBURY DR FROM LANCASTER DR TO WILTON WAY	3	4	0						25,000
10401		2016-1154	CIPP SEWER CANTERBURY DR AND LANCASTER DR	3	4	0						19,000
10401		2016-1155	CIPP SEWER 1515 SOUTH DEVONSHIRE DR TO LANCASTER DR	3	4	0						14,000
10401		2016-1156	CIPP SEWER ON UTE DR FROM INDIAN HILL CIRCLE TO EAGLE WAY	3	4	0						18,000
10401		2016-1157	CIPP SEWER ON COMANCHE DR AND EAGLE WAY	3	4	0						5,000
10401		2016-1158	CIPP SEWER ON WASATCH DR BETWEEN 1700 SOUTH AND SKYLINE DR	3	4	0						20,000
10401		2016-1172	CIPP SEWER FROM 1911 SOUTH FOOTHILL TO 1975 SOUTH FOOTHILL	3	4	0						19,000
10401		2016-1197	CIPP SEWER ON LOGAN WAY AT 1700 SOUTH	3	4	0						10,000
10401		2016-1198	CIPP SEWER ON BLAINE AVE AND TEXAS ST	3	4	0						15,000
10401		2016-1207	CIPP SEWER ON INDUSTRIAL AVE AND 1700 SOUTH	3	4	0						7,000
10401		2016-1209	CIPP SEWER ON 2300 EAST BETWEEN CLUBHOUSE DR AND MAYWOOD DR	3	4	0						18,000
10401		2016-1212	CIPP SEWER FROM 2526 EAST COMMONWEALTH TO WYOMING ST	3	4	0						20,000
10401		2016-1213	CIPP SEWER ON 2000 EAST BETWEEN WILSON AVE AND DOWNINGTOWN AVE	3	4	0						18,000
10401		2016-1214	CIPP SEWER FROM 1838 EAST DOWNINGTOWN AVE TO 1800 EAST	3	4	0						23,000
10401		2016-1215	CIPP SEWER ON 2100 EAST FROM WILSON AVE TO DOWNINGTOWN AVE	3	4	0						14,000
10401		2016-1216	CIPP SEWER ON 2000 EAST FROM DOWNINGTOWN AVE TO GARFIELD AVE	3	4	0						18,000
10401		2016-1218	CIPP SEWER ON 1700 SOUTH FROM 1860 EAST TO 1800 EAST	3	4	0						19,000
10401		2016-1219	CIPP SEWER ON 1700 EAST AND PARLEYS CANYON BL	3	4	0						4,000
10401		2016-1229	CIPP SEWER ON GLENMARE ST BETWEEN STRATFORD AVE AND 2700 SOUTH	3	4	0						19,000
10401		2016-1239	CIPP SEWER ON BEVERLY ST BETWEEN ATKIN AVE AND CLAYBOURNE AVE	3	4	0						17,000
10401		2016-1241	CIPP SEWER ON HUDSON AVE BETWEEN HIGHLAND DRIVE AND 1400 EAST	3	4	0						23,000
10401		2016-1242	CIPP SEWER ON SYLVAN AVE BETWEEN 1900 EAST AND 2000 EAST	3	4	0						22,000
10401		2016-1245	CIPP SEWER ON THIRD AVE AT CANYON ROAD	3	4	0						13,000
10401		2016-1246	CIPP SEWER ON STATE STREET BETWEEN 126 N AND 200 NORTH	3	4	0						19,000
10401		2016-1248	CIPP SEWER ON C STREET BETWEEN FIFTH AVE AND SIXTH AVE	3	4	0						24,000
10401		2016-1253	CIPP SEWER ON 300 NORTH BETWEEN 550 WEST AND 600 WEST	3	4	0						20,000
10401		2016-1256	CIPP SEWER ON UNIVERSITY BLVD (500 S) FROM 1500 EAST TO GUARDSMAN WAY	3	4	0						17,000

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10401		2015-0309	500 SOUTH - 3415 WEST TO 3600 WEST	3	3	0						224,000
10401		2016-0964	CIPP SEWER PIPE 1480 EAST TOMAHAWK DRIVE	3	3	0						12,000
10401		2016-0965	CIPP SEWER PIPE FROM 1536 E TOMAHAWK DR TO CHANDLER DR	3	3	0						20,000
10401		2016-0821	ELGIN AVE 1000 E - 950 E	2	4	0						200,000
10401		2017-1302	LEARNED AVE 1034 TO 1000 WEST	2	4	0						10,000
10401		2017-1307	2600 EAST 1750 TO 1889 SOUTH	2	4	0						50,000
10401		2016-0967	8-IN CIPP SEWER LINE FROM CAMBRIDGE WAY TO 1330 EAST PERRYS HOLLOW	3	3	0						9,000
10401		2016-0974	CIPP SEWER ON 1500 WEST FROM TALISMAN DR TO 895 NORTH	3	3	0						14,000
10401		2016-0977	CIPP SEWER BONNEVILLE DR	3	3	0						19,000
10401		2016-0980	CIPP SEWER ON OQUIRRH DRIVE	3	3	0						21,000
10401		2016-0982	CIPP SEWER AT ST MARY'S WAY AND OQUIRRH DRIVE	3	3	0						24,000
10401		2016-1006	CIPP SEWER ON 4TH AVE FROM VIRGINIA ST TO U ST	3	3	0						22,000
10401		2016-1007	CIPP SEWER ON FORT DOUGLAS CIRCLE	3	3	0						15,000
10401		2016-1015	CIPP SEWER ON BERKELEY ST AND WILMINGTON AVE	3	3	0						19,000
10401		2016-1049	CIPP SEWER ON TOMAHAWK DR	3	3	0						10,000
10401		2016-1051	CIPP SEWER ON 1675 EAST TOMAHAWK DR	3	3	0						13,000
10401		2016-1052	CIPP SEWER ON VIRGINIA ST FROM CHANDLER DR TO KRISTIANNA CIR	3	3	0						12,000
10401		2016-1053	CIPP SEWER ON KRISTIANNA CIR AND VIRGINIA ST	3	3	0						18,000
10401		2016-1054	CIPP SEWER ON ROUNDTOFT DR TO EAST CAPITOL BLVD	3	3	0						10,000
10401		2016-1062	CIPP SEWER ON SECOND AVE FROM L STREET TO M STREET	3	3	0						21,000
10401		2016-1092	CIPP SEWER ON 2100 SOUTH 1410 EAST	3	3	0						29,000
10401		2016-1127	CIPP SEWER ON 550 EAST NORTHHILLS DR	3	3	0						15,000
10401		2017-1305	1600 SOUTH INDUSTRIAL ROAD	1	5	0						25,000
10401		2016-0969	CIPP SEWER LINE ON 300 WEST FROM 400 NORTH TO BISHOP PL	3	2	0						1,000
10401		2016-1066	CIPP SEWER ON M STREET BETWEEN FIRST AND SECOND AVE	3	2	0						15,000
10401	525002849		1700 NORTH UNDER CITY DRAIN - BYPASS AND REHABILIATION	5	5	40,000	400,000					
			POINT REPAIR PROGRAM (VARIOUS LOCATIONS)									
10401	525002690	2015-0477	POINT REPAIRS IN SUPPORT OF CIPP PROGRAM (VARIOUS LOCATIONS)	3	5	0		350,000	350,000	350,000	350,000	1,400,000
			TOTAL COLLECTION LINES			1,501,058	8,475,500	7,503,000	7,325,000	13,720,000	7,050,000	37,188,000
			MANHOLE REHAB PROGRAM (VARIOUS LOCATIONS)									
10401		2015-0478	MANHOLE REHAB PROGRAM (VARIOUS LOCATIONS)	5	5	0	450,000	350,000	350,000	350,000	350,000	2,100,000
	525002832		500 SOUTH SURPLUS SIPHON VAULT REPLACEMENT (MH 05225)		5	90,779	400,000					
						90,779	850,000	350,000	350,000	350,000	350,000	2,100,000
			OTHER PROJECTS									
10401	525002839	2015-0376	ON-CALL TASK ORDER GENERAL CONSTRUCTION SERVICES (VARIOUS LOCATIONS)		5	300,000						
10401	52520035	2015-0485	CONTRIBUTIONS BY DEVELOPERS	5	5	0	500,000	500,000	500,000	500,000	500,000	2,000,000
	52510023	2016-1267	COLLECTION SYSTEM PROJECTS GENERAL SUPPORT - TASK 2	5	0	1,500,000	2,000,000	2,000,000	1,500,000	1,500,000	750,000	750,000
	525002786		PROGRAM MANAGEMENT SERVICES - TASK 1			0	350,000	350,000	350,000	350,000	350,000	350,000
		2016-0839	TDS REDUCTION PROGRAM	1	0	0						500,000
						1,800,000	2,850,000	2,850,000	2,350,000	2,350,000	1,600,000	3,600,000
			MASTER PLAN IMPLEMENTATION PROGRAM									

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10401	525002524	2015-0279	500 SOUTH INTERCEPTOR - ORANGE TO 1000 WEST		5	1,720,290						
10401	525002698	2015-0286	MP12A - 700 SOUTH CAPACITY UPGRADES – 4650 WEST TO 3400 WEST	5	5	14,004,129	250,000					
10401	52490785	2016-1260	500 SOUTH DIVERSION, PHASE II (PUMP STATION)	5	5	11,976,147	2,000,000					
10401	525002850	2016-0950	MP13 - BECK STREET TRUNK REPLACEMENT FROM 500 SOUTH AND STATE STREET TO 700 S(	5	5	522,328	1,000,000	6,000,000	11,000,000			
10401	525002376		1800 NORTH BECK STREET TO THE PRETREATMENT PLANT	5	5	2,608,982	3,000,000	12,000,000	6,000,000			
10401	525002423	2015-0320	MP8A - 1500 SOUTH - 2700 WEST TO REDWOOD ROAD	4	5	840,877	500,000					
10401	525002631	2015-0280	ORANGE STREET - PHASE IV - INDIANA TO 1500 SOUTH	5	4	0						6,131,000
10401	52490787	2015-0269	MP12D - 700 SOUTH LIFT STATION (SS 10)	5	4	493,341	7,000,000					
10401	2016-0929	2016-0929	MP16 - 600 WEST AND 700 SOUTH TO 500 WEST AND 800 SOUTH	5	4	0					1,400,000	
10401	2016-0930	2016-0930	MP17A - 900 SOUTH FROM RICHARD STREET TO MAIN STREET	5	4	0	250,000	1,000,000				
10401	2016-0931	2016-0931	MP17B - MAIN STREET FROM 800 SOUTH TO 900 SOUTH	5	4	0						809,100
10401	2016-0932	2016-0932	MP18 - 300 WEST FROM FAYETTE AVE TO 900 SOUTH	5	4	0						800,000
10401	2016-0940	2016-0940	MP19 - FOLSOM AVENUE FROM 500 WEST TO 1000 WEST	5	4	0						13,500,000
10401	2016-0941	2016-0941	MP20 - 700 WEST FROM 900 SOUTH TO 600 SOUTH	5	4	0						5,500,000
10401	2016-0942	2016-0942	MP21 - 100 SOUTH AND 300 WEST DIVERSION	5	4	0						300,000
10401		2015-0284	500 S SEWER REPLACEMENT FROM 3200 W TO ORANGE STREET	4	4	0						17,150,000
10401	2015-0322	2015-0322	MP28 - NORTH TEMPLE - AIRPORT TO ORANGE STREET	4	4	0					750,000	15,500,000
10401	2016-0949	2016-0949	MP26 - SOUTH TEMPLE AND 400 WEST DIVERSION	4	4	0						250,000
10401	525002577	2016-0849	MP15 - 700 SOUTH INTERCEPTOR CAPACITY UPGRADE	4	4	508,500	3,000,000	500,000				
10401	525002584	2016-0905	MP7 - 100 SOUTH 1200 EAST DIVERSION FOR CAPACITY	4	4	0	400,000					300,000
10401	2016-0943	2016-0943	MP22 - PIONEER ROAD FROM CALIFORNIA AVENUE TO 1500 SOUTH	4	4	0				1,500,000	6,500,000	1,000,000
10401	2016-0947	2016-0947	MP24 - 400 SOUTH FROM 300 WEST TO 600 WEST	4	4	0						3,000,000
10401	2016-0953	2016-0953	MP31 - 600 SOUTH FROM 800 WEST TO 900 WEST	4	3	0						2,000,000
10401	525002507	2015-0321	MP8B - 3230 WEST - 1820 SOUTH TO 1670 SOUTH	3	4	397,056				1,000,000	5,000,000	
10401	2016-0952	2016-0952	MP30 - 200 EAST FROM 300 SOUTH TO 500 SOUTH	4	3	0						2,000,000
10401		2016-0946	MP23 - PARALLEL 1000 WEST 48-INCH TRUNK	4	3	0						20,000,000
10401	2016-1195	2016-1195	MP29 - BECK STREET TRUCK REPLACEMENT FROM 200 SOUTH AND 300 WEST TO STATE STR	4	3	0						16,000,000
10401		2016-0841	500 S. PUMP AND THIRD FORCE MAIN INSTALLATION	5	1	0						10,000,000
10401	2016-0954	2016-0954	MP32 - 700 WEST FROM 700 SOUTH TO 500 SOUTH (EAST SIDE OF I-15)	3	3	0						3,000,000
10401	2016-0955	2016-0955	MP33 - 1300 EAST FROM 400 SOUTH TO 500 SOUTH	3	3	0	450,000					
10401		2015-0660	SATELLITE TREATMENT PLANT	5	0	0						405,500,000
10401			700 S. PUMP AND THIRD FORCE MAIN INSTALLATION			0						10,000,000
						33,071,650	17,850,000	19,500,000	17,000,000	2,500,000	13,650,000	532,740,100
			Total Collection System			39,132,179	36,630,500	38,558,000	32,575,000	25,370,000	28,050,000	587,528,100
	2730.20		**LANDSCAPING**									3,372,750
10401	525002689		NORTHWEST OIL DRAIN			0	150,000					
						0	150,000	0	0	0	0	3,372,750
			TOTAL CAPITAL IMPROVEMENTS			60,892,051	98,370,500	125,728,000	210,160,000	162,630,000	94,660,000	618,230,850

SEWER UTILITY CAPITAL PURCHASES BUDGET
Five Year Projected Budget FY2020-2024

COST CENTER	OBJECT CODE	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	Comments	CRITICALITY RATING	CONDITION RATING	PAST YEAR 2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
	2710.10			LAND										
5210401			2015-0481	500 SOUTH LAND PURCHASE		5	5		4,100,000					
5210401				LAND EASEMENT FOR 700 SOUTH SEWER LINE		4	4							
5210401			2016-0887	SHURTLEFF AND ANDREWS SECONDARY ACCESS		4	4		500,000					
5210401				LAND EASEMENT FOR 500 SOUTH MP PROJECT TO ORANGE STREET		4	4		1,000,000					
5210401			2016-0870	EASEMENT NORTH OF OQUIRRH DR		4	4							
								0	5,600,000	0	0	0	0	0
	2750.10			AUTOMOBILES & TRUCKS										
5212201	2750.10			Electric Club Car Qty. 4										
5210801	2750.10			Transit Van w/Upfit										
5210101	2750.10			3/4 Ton Truck w/Service Body 4X4										
5210601	2750.10		3387	Int. 1 ton Cab-n-Chassis w/ Dump Bed				47,157						
5210101	2750.10		36910	GMC 3/4 ton Ext Cab Pick-up Truck				56,165						
5211201	2750.10		3418	Chev 3/4 ton Ext Cab Pick-up Truck				34,390						
5211201	2750.10		3425	Chev 1 ton Cab-n-Chassis Util. Bed & Crane				31,640						
5211201	2750.10		3488	GMC 1/2 ton Cab-n-Chassis w/ Utility Body				30,031						
5212201	2750.10		49/63/58/62	Golf Cart Enclosed Cab Dump Bed Qty 4				56,000						
5210401	2750.10			CHEV OR SIMILAR MID-SIZED 4X4 PICK UP W/BED COVER	Jason				30,000					
5212201	2750.10		3428	Replace Volvo Wg64, Mack Granite 64 br	Jamey				190,000					
5212201	2750.10		34030	Replace Stering LT9500, Mack Granite 64 br	Jamey				190,000					
5212201	2750.10		34310	Replace International 2674 6x4, Mack Granite 64 br	Jamey				190,000					
5212201	2750.10		34020	Replace International 7400 4x2, Vactor	Jamey				500,000					
5212301	2750.10		3485	Replace Ford F-350, Chevrolet Silverado 3500HD 4x4	Jamey				40,000					
5212301	2750.10		3458	GMC Sierra 3500HD Flatbed Dump	Jamey				49,000					
5210601	2750.10		33080	Mack GU713	Randy				460,000					
5210601	2750.10		33880	GMC Sierra 2500	Randy				31,000					
5210101	2750.10		33890	GMC Sierra 2500 W/Service Body	Randy				37,500					
5212301				VARIOUS										
								255,383	1,717,500	0	0	0	0	0
	2750.30			FIELD MAINTENANCE EQUIP.										
5210601				BACKHOE EXCHANGE				8,000	8,000	8,000	8,000	8,000	8,000	
5210801				REHAB OLD CCTV VAN										
5210601				VARIOUS					400,000	400,000	400,000	400,000	400,000	
5210601				PUMP TRUCK - LARGE DIAMETER PIPE CLEANING MACHINE										
5210601				Cat Backhoe Buyback Program				9,000						
5211201				40 Ton Rough Terrain Crane for Water Rec				462,403						
5210601				BOBCAT SKID STEER										
								479,403	408,000	408,000	408,000	408,000	408,000	0
	2760.10			PUMP PLANT EQUIPMENT										

SEWER UTILITY CAPITAL PURCHASES BUDGET
Five Year Projected Budget FY2020-2024

COST CENTER	OBJECT CODE	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	Comments	CRITICALITY RATING	CONDITION RATING	PAST YEAR 2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
5211201	2760.10			SLC WRF Pump Plant Exterior Lighting Upgrades	Michael				35,000					
5211201	2760.10			SLC WRF Influent Pump Discharge Ball Valves	Michael				200,000					
									235,000	0	0	0	0	0
	2760.20			TREATMENT PLANT EQUIPMENT										
5212201	2760.20			COMPRESSORS AND BLOWERS										
5212201	2760.20			PUMPS										
5211201	2760.20			AERATION BASIN DRAINAGE PUMP REPLACEMENTS (10)				100,000						
5211201	2760.20			REPLACEMENT #2 WATER PUMP				100,000						
5211201	2760.20			PUMP PLANT GRIT PUMP REPLACEMENT (2)				6,778						
5211201	2760.20			SUPPLIED AIR SYSTEM REPLACEMENT CL2 BLDG				20,000						
5211201	2760.20			DIGESTER ROOF WALK WAY IMPROVEMENTS				10,000						
5211201	2760.20			HVAC REPLACEMENTS (3)				120,000						
5211101	2760.20			XPE205 METTLER TOLEDO ANALYTICAL BALANCE										
5211101	2760.20			LACHAT/HATCH 2-CHANNEL FIA + IC CONFIGURATION										
5211201	2760.20			Primary Trickling Filter Overflow Gate	Michael				20,000					
5211201	2760.20			SLC WRF HVAC Improvements	Michael									
5211201	2760.20			East Maitenance	Michael				18,000					
5211201	2760.20			Pre Treatment	Michael				5,500					
5211201	2760.20			Switch Gear #3	Michael				5,500					
5211201	2760.20			Chillers (2)	Michael				80,000					
5211201	2760.20			Administration	Michael				40,000					
5211201	2760.20			Digester MCC Room	Michael				5,000					
5211201	2760.20			South Ras	Michael				5,500					
5211201	2760.20			North Ras	Michael				5,500					
5211201	2760.20			TWAS Electrical Room	Michael				5,500					
5211201	2760.20			All Swamp Coolers (6)	Michael				27,000					
5211201	2760.20			SLC WRF Grease Pump	Michael				20,000					
5211201	2760.20			SLC WRF Snail Pump	Michael				15,000					
5211201	2760.20			SLC WRF Trickling Filter Motor VFD Replacement (6)	Michael				6,000					
5211201	2760.20			SLC WRF Bio Gas Heat Exhanger Upgrade	Michael				75,000					
5211201	2760.20			SLCWRF Co-Gen Controls	Michael				50,000					
5211201	2760.20			SLCWRF #2 Water Filters (2)	Michael				90,000					
5211201	2760.20			SLCWRF Co-Gen Oil Filter Replacement (2)	Michael				70,000					
5212201				VARIOUS						225,000	225,000	225,000	225,000	
								356,778	543,500	225,000	225,000	225,000	225,000	450,000
	2760.30			TELEMETERING EQUIPMENT										
5211201	52540048			TELEMETERING UPGRADE - REPLACE										
5210101				SCADA SYSTEM REPLACE				10,000	10,000	10,000	10,000	10,000	10,000	
								10,000	10,000	10,000	10,000	10,000	10,000	20,000
	2760.50			OFFICE FURNITURE & EQUIPMENT										

SEWER UTILITY CAPITAL PURCHASES BUDGET
Five Year Projected Budget FY2020-2024

COST CENTER	OBJECT CODE	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	Comments	CRITICALITY RATING	CONDITION RATING	PAST YEAR 2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
5211301				Server replacement "SLCIWRDB"				9,000						
5211701				Core Switch										
5212401				FULL FUNCTION PRINTER REPLACEMENT PRE-TREATMENT SMALL				5,765						
5212201				VARIOUS				20,000	20,000	20,000	20,000	20,000	20,000	
								34,765	20,000	20,000	20,000	20,000	20,000	20,000
	2760.90			OTHER NON-MOTIVE EQUIPMENT										
5210601				TOW ALONG CEMENT MIXER										
5212201				STATIONARY SAMPLER W/ENCLOSURE										
5212401				VARIOUS NON-MOTIVE EQUIPMENT					160,000	160,000	160,000	160,000	160,000	
5212201				UPGRADE LAB ANALYTICLA EQUIPMENT										
5212201				Washer Compactor for Primary Sludge Screens										
5210601				Vanguard System										
5210601				HANDHELD RADIO REPLACEMENT				57,902						
5210801				REPLACEMENT PUSH CAMERA				11,000						
5210801				NEW LATERAL LAUNCH ADD ON SYSTEM				67,338						
5211101				LABORATORY SPECTROPHOTOMETER REPLACEMENT				5,000						
5211101				LABORATORY DIGITAL BALANCE REPLACEMENT				5,000						
5211401				SURVEY GRADE GPS UNIT				20,000						
								166,240	160,000	160,000	160,000	160,000	160,000	0
				TOTAL CAPITAL OUTLAY				**1,302,569**	**8,694,000**	**823,000**	**823,000**	**823,000**	**823,000**	**490,000**

Stormwater Utility- Budget Summary and Cash Flow

STORMWATER UTILITY
ENTERPRISE FUND
BUDGET SUMMARY
FY 2020-2022

SOURCES	ACTUAL 2017-18	AMENDED BUDGET 2018-19	PROJECTED ACTUAL 2018-19	Rate increase 10% PROPOSED BUDGET 2019-20	Rate increase 10% FORECAST BUDGET 2020-21	Rate increase 10% FORECAST BUDGET 2021-22
REVENUES						
METERED SALES	$ 8,508,507	$ 8,855,000	$ 8,855,000	**$ 9,740,500**	$ 10,714,550	$ 11,678,860
INTEREST INCOME	124,773	33,000	33,000	**20,820**	174,816	38,338
OTHER REVENUES	1,027,830	1,000	1,000	**1,000**	1,000	1,000
TOTAL REVENUES	$ 9,661,110	$ 8,889,000	$ 8,889,000	**$ 9,762,320**	$ 10,890,366	$ 11,718,198
OTHER SOURCES						
GRANTS & OTHER RELATED REVENUES	354,475	650,000	650,000	**516,000**	516,000	516,000
COUNTY FLOOD CONTROL	-	-	-	**-**	-	-
IMPACT FEES	366,456	200,000	200,000	**200,000**	200,000	200,000
SHORT-TERM FINANCING	-	1,355,000	-	**-**	-	-
BOND PROCEEDS	-	-	-	**14,581,000**	-	6,159,200
TOTAL OTHER SOURCES	$ 720,931	$ 2,205,000	$ 850,000	**$ 15,297,000**	$ 716,000	$ 6,875,200
TOTAL SOURCES	$ 10,382,041	$ 11,094,000	$ 9,739,000	**$ 25,059,320**	$ 11,606,366	$ 18,593,398
EXPENSES & OTHER USES						
EXPENDITURES						
PERSONNEL SERVICES	$ 2,390,383	$ 2,872,608	$ 2,872,608	**3,187,954**	$ 3,315,474	$ 3,448,092
OPERATING & MAINTENANCE	152,863	186,450	186,450	**200,950**	204,769	208,864
TRAVEL & TRAINING	7,009	12,750	12,750	**16,265**	16,590	16,922
UTILITIES	188,079	244,045	244,045	**244,045**	248,926	253,903
TECHNICAL SERVICES	632,693	2,141,221	2,141,221	**1,304,999**	1,230,399	1,241,007
PUBLIC SERVICES / STREET SWEEPING	819,605	819,605	819,605	**819,605**	835,997	852,717
DATA PROCESSING	317,811	239,700	239,700	**304,000**	310,080	316,282
FLEET MAINTENANCE	223,731	214,000	214,000	**214,000**	218,280	222,645
ADMINISTRATIVE SERVICE FEE	101,615	130,000	130,000	**120,000**	122,400	124,848
PAYMENT IN LIEU OF TAXES	109,785	125,942	125,942	**100,434**	102,443	104,492
BILLING COST	423,849	554,117	554,117	**545,417**	556,325	567,452
RISK MANAGEMENT	57,985	86,983	86,983	**84,842**	86,539	88,269
TRANSFERS TO GENERAL FUND	-	4,000	4,000	**4,000**	4,080	4,162
OTHER CHARGES AND SERVICES	98,689	27,899	27,899	**25,857**	27,101	27,641
TOTAL EXPENDITURES	$ 5,524,097	$ 7,659,320	$ 7,659,320	**$ 7,172,368**	$ 7,279,403	$ 7,477,296
OTHER USES						
CAPITAL OUTLAY	197,620	515,568	515,568	**728,149**	620,000	620,000
CAPITAL IMPROVEMENT BUDGET	2,392,384	6,522,769	3,783,053	**12,744,000**	7,630,000	4,371,000
COST OF DEBT ISSUANCE	-	10,000	-	**81,000**	-	34,200
DEBT SERVICES	1,017,494	1,014,000	1,014,000	**1,225,000**	1,649,000	1,652,000
TOTAL OTHER USES	$ 3,607,498	$ 8,062,337	$ 5,312,621	**$ 14,778,149**	$ 9,899,000	$ 6,677,200
TOTAL USES	$ 9,131,595	$ 15,721,657	$ 12,971,941	**$ 21,950,517**	$ 17,178,403	$ 14,154,496
EXCESS REVENUE AND OTHER SOURCES OVER (UNDER) USES	$ 1,250,446	$ (4,627,657)	$ (3,232,941)	**$ 3,108,803**	$ (5,572,037)	$ 4,438,902
OPERATING CASH BALANCES						
BEGINNING JULY 1	$ 5,316,077	$ 6,566,523	$ 6,566,523	**$ 3,333,582**	$ 6,442,385	$ 870,348
ENDING JUNE 30	$ 6,566,523	$ 1,938,866	$ 3,333,582	**$ 6,442,385**	$ 870,348	$ 5,309,250
Cash Reserve Ratio	119%	25%	44%	90%	12%	71%

Cash reserve goal above 10%

STORMWATER UTILITY
CASH FLOW
FY 2020 BUDGET
AND FY 2021-2024 FORECAST

10%,10%,9%,6%,5% Rates
$20.6M in Bonds,$14.5M FY20 and $6.2M FY22
New Debt Pmts $3.1M thru FY24
100% Capital Budget FY 20 thru 24

	ACTUAL YEAR 2017-2018	PROJECTED YEAR 2018-2019	BUDGET YEAR 2019-2020	BUDGET YEAR 2020-2021	BUDGET YEAR 2021-2022	BUDGET YEAR 2022-2023	BUDGET YEAR 2023-2024
STORMWATER CHARGES	8,508,507	8,855,000	9,740,500	10,714,550	11,678,860	12,379,591	12,998,571
OTHER INCOME	1,027,830	1,000	1,000	1,000	1,000	1,000	1,000
INTEREST INCOME	124,773	33,000	20,820	174,816	38,338	106,254	51,104
OPERATING INCOME	9,661,110	8,889,000	9,762,320	10,890,366	11,718,198	12,486,845	13,050,675
OPERATING EXPENDITURES	(5,524,097)	(7,659,320)	(7,172,368)	(7,279,403)	(7,477,296)	(7,681,804)	(7,343,160)
NET INCOME EXCLUDING DEP.	4,137,013	1,229,680	2,589,952	3,610,963	4,240,902	4,805,041	5,707,515
IMPACT FEES	366,456	200,000	200,000	200,000	200,000	200,000	200,000
SHORT-TERM FINANCING							
NET BOND PROCEEDS			14,500,000		6,125,000		
COST OF ISSUANCE (PROCEEDS)		0	81,000	0	34,200	0	0
COST OF ISSUANCE (EXP.)		0	(81,000)	0	(34,200)	0	0
OTHER CONTRIBUTIONS	354,475	650,000	516,000	516,000	516,000	516,000	516,000
CAPITAL OUTLAY	(197,620)	(515,568)	(728,149)	(620,000)	(620,000)	(620,000)	(620,000)
SHORT-TERM DEBT							
DEBT SERVICE (NEW)		0	(213,000)	(638,000)	(638,000)	(638,000)	(925,000)
DEBT SERVICE	(1,017,494)	(1,014,000)	(1,012,000)	(1,011,000)	(1,014,000)	(1,009,000)	(1,018,000)
OTHER INCOME & EXPENSE	(494,183)	(679,568)	13,262,851	(1,553,000)	4,569,000	(1,551,000)	(1,847,000)
GENERATED FOR CAPITAL	3,642,830	550,112	15,852,803	2,057,963	8,809,902	3,254,041	3,860,515
CAPITAL IMPROVEMENTS	(2,392,384)	(3,783,053)	(12,744,000)	(7,630,000)	(4,371,000)	(7,023,000)	(4,300,000)
BEGINING CASH BALANCE	5,316,077	6,566,523	3,333,582	6,442,385	870,348	5,309,250	1,540,291
CASH INCREASE/(DECREASE)	1,250,446	(3,232,941)	3,108,803	(5,572,037)	4,438,902	(3,768,959)	(439,485)
ENDING BALANCES	6,566,523	3,333,582	6,442,385	870,348	5,309,250	1,540,291	1,100,806
AMOUNT RESTRICTED							
DEBT SERVICE COVERAGE	**4.07**	**1.21**	**2.11**	**2.19**	**2.57**	**2.92**	**2.94**
RATE CHANGE	0%	10%	10%	10%	9%	6%	5%
Cash Reserve Ratio	**119%**	**44%**	**90%**	**12%**	**71%**	**20%**	**0**
Minimum Reserve	**552,410**	**765,932**	**717,237**	**727,940**	**747,730**	**768,180**	**734,316**
Ending Reserve Available for Capital	**6,014,113**	**2,567,650**	**5,725,148**	**142,408**	**4,561,520**	**772,111**	**366,490**
DEBT SERVICE % OF GROSS OPERATING REVENU	**11%**	**11%**	**13%**	**15%**	**14%**	**13%**	**15%**
RESIDENTIAL BILL FOR 1 ERU (or .25 acre)	**4.49**	**4.94**	**5.43**	**5.97**	**6.51**	**6.90**	**7.25**

STORMWATER CIP BUDGET
Five Year Projected Budget FY2020 -2024

COST CENTER	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	CRITICALITY RATING	CONDITION RATING	PAST YEAR 2018-19 (Calc'd from P6)	BUDGET YEAR 2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
53-10301	2720.05		**LIFT STATIONS**									
10301	53471046	2015-0434	LIFT STATION REHABILITATION AT 400 WEST AND 1300 SOUTH - NORTH SIDE	5	4	171,097						400,000
10301	53470852		LIFT STATION AT SURPLUS CANAL AND INDIANA REPAIRS	4	5	7,501						
10301	53471040		SWEDE TOWN LIFT STATION	3	0	40,514		700,000				
10301	534710104	2015-0435	VARIOUS PUMP STATIONS	5	5	50,000	50,000	50,000	50,000	50,000		
10301	53471038	2015-0140	OIL DRAIN LIFT STATION - GABION BASKETS RECONSTRUCTION	5	4	0						58,000
10301	534710103	2015-0135	SD LIFT STATION AT 650 WEST AND 500 NORTH IMPROVEMENTS	4	4	15,000	14,000					107,500
10301		2015-0144	HARTLAND LIFT STATION ABANDONMENT	1	5	0						50,000
10301		2015-0145	300 WEST 1300 SOUTH LIFT STATION ABANDONMENT	1	2	0						50,000
						$ 284,112	$ 64,000	$ 750,000	$ 50,000	$ 50,000	$ -	$ 665,500
53-10301	2730.20		**DETENTION BASINS**									
53-10301	2730.12		**COLLECTION MAINS**									
	53470882	2017-2101	LEE DRAIN - PIPE OPEN CHANNEL WEST OF PIONEER ROAD	5	4	60,000		700,000				
	53470974		ORANGE STREET STORM DRAIN - NORTH TEMPLE TO I-80	5	0	45,000						500,000
	53470835	2015-0142	MIDDLE BRIGHTON RAILROAD CULVERT REHABILITATION	5	4	0		20,000				260,000
		2017-2034	RED BUTTE CREEK CULVERT AT 900 SOUTH - LINER	5	4	0					300,000	
	534701001	2017-2100	PIPE REPLACEMENT AT 750 S 1100 EAST	4	5	3,000						
	534700998	2016-0746	ABANDONMENT OF STORMWATER DITCH FROM WARM SPRINGS ROAD TO THE NORTHWEST DRAIN	4	4	10,000	60,000	250,000				
	534700997	2017-2098	PIPE REPLACEMENT AT 746 SOUTH ELIZABETH	3	5	5,250						
		2015-0131	REPAIR OUTLETS ON THE LEE DRAIN AT 4800 WEST	3	4	0			21,000	170,000		
	53470970	2016-0853	DITCH BANK EROSION PROTECTION - 600 NORTH 550 WEST	2	3	6,039	10,000	60,000				
	53470937	2015-0130	WQ - MONTAGUE CUTOFF- NEW 18" STORM DRAIN	4	0	0						61,500
		2015-0584	FOOTHILL DRIVE (2800 E) – EMIGRATION CREEK TO 2300 EAST	4	0	0						500,000
	53470881	2015-0143	1500 EAST STORM DRAIN	3	0	0				203,000		
	534701000	2016-0750	1700 SOUTH STORM DRAIN, FROM 2100 EAST TO EMIGRATION CREEK	3	0	211,811	1,100,000	1,100,000				
		2015-0585	600 EAST – 900 SOUTH TO THE AVENUES	2	0	0						4,200,000
	53470995		PARLEY CREEK STORM WATER OUTFALL			11,766						
	53470994		CITY DRAIN CROSSING AT HUNTER STABLES			259,175						
	534701013		1700 S 18" STORM DRAIN FROM 1700 E TO 1900 E			399,000						
	53470988		7200 WEST AND NORTH TEMPLE CULVERT REPLACEMENT AND CANAL REHAB			0	250,000					
		2016-0855	NORTHWEST QUADRANT STORMWATER BETTERMENTS	5	5	0						14,000,000
		2018-1040	PIPING OF GOGGIN DRAIN AT HAROLD GATTY DRIVE	3	4	0						335,300
						$ 1,011,040	$ 1,420,000	$2,130,000	$ 21,000	$ 373,000	$ 300,000	$19,856,800
			CITY, COUNTY, STATE AND MISC. DRIVEN PROJECTS									
	53470979		PROGRAM MANAGEMENT TOOLS	5	5	0	150,000					
10301	53470947	2016-0736	INDIANA AVENUE STORM DRAIN REDWOOD ROAD TO 3400 WEST	4	0	128,175						
10301	53470972		GLADIOLA AVE PHASE 1 - 500 SOUTH TO 900 SOUTH			869,550						
10301	53470946	2015-0436	STORM DRAIN CITY/COUNTY/STATE PROJECTS	5	5	0	150,000	150,000	150,000	150,000	150,000	
10301	534720005	2017-2033	STORMWATER RECIEVING STATION	4	4	9,000	150,000					
10301	53470971	2016-0741	1300 EAST - STORM DRAIN	3	4	377,165	1,200,000					
	53470936	R18-0054	NEW STORM DRAIN ON 5500 WEST FROM 700 SOUTH CUL-DE-SAC TO THE NORTH			111,515	1,500,000					
10301	513000039	2015-0723	SURPLUS CANAL ENCROACHMENT AND PERMITTING	5	5	25,000	50,000	50,000	50,000	50,000	50,000	
			700 SOUTH SD, MIDDLE BRIGHTON TO 5600 WEST			0	800,000	800,000	800,000			
			2700 SOUTH - HIGHLAND TO 20TH EAST			0	250,000					
			1500 SOUTH - REDWOOD TO 2700 WEST			0	800,000					
		s	OVERLAY - VARIOUS			0			750,000	750,000		

STORMWATER CIP BUDGET
Five Year Projected Budget FY2020 -2024

COST CENTER	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	CRITICALITY RATING	CONDITION RATING	PAST YEAR 2018-19 (Calc'd from P6)	BUDGET YEAR 2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
	534700999	2015-0126	700 WEST - 2100 SOUTH TO 1700 SOUTH - PIPING OF OPEN DITCH	4	3	0	1,000,000					
			LOCAL STREET DISTRICT 1 & 7			0	500,000					
			500 EAST - 1700 SOUTH TO 2700 SOUTH			0	800,000					
			2000 EAST - PARLEY'S TO CITY LIMIT			0	250,000					
			900 SOUTH - 900 WEST TO 300 WEST, WEST TEMPLE TO 900 EAST			0	1,000,000					
			300 WEST - 900 SOUTH TO 2100 SOUTH			0		550,000	550,000			
			900 EAST - HOLLYWOOD TO 2700 SOUTH			0		1,300,000				
			100 SOUTH - NORTH CAMPUS DRIVE TO 900 EAST			0		275,000				
			LOCAL STREETS DISTRICT 3 & 6			0		500,000				
			200 SOUTH - 400 WEST TO 900 EAST			0			125,000	125,000		
			LOCAL STREETS DISTRICTS 2 & 5			0			625,000			
			1100 EAST HIGHLAND , RAMONA TO WARNOCK			0				2,200,000		
			1100 EAST - 900 SOUTH TO RAMONA			0				900,000		
			1700 EAST - 1700 SOUTH TO 2700 SOUTH			0				875,000		
			300 NORTH - 300 WEST TO 1000 WEST			0				250,000		
			LOCAL STREETS DISTRICT 4 & 7			0				500,000		
			VIRGINIA STREET - SOUTH TEMPLE TO 11TH AVE			0					1,700,000	
			1300 EAST - 2100 SOUTH TO 3000 SOUTH			0					550,000	
			W TEMPLE - NORTH TEMPLE TO 400 SOUTH			0					250,000	
			LOCAL STREETS 3 & 6			0					500,000	
			2100 SOUTH - 700 EAST TO 1700 EAST			0						2,000,000
			LOCAL STREETS DISTRICT 1, 4 & 5			0						500,000
		Bond Alternativ	GLADIOLA STREET - 900 SOUTH TO CALIFORNIA			0						
		Bond Alternativ	300 WEST - 400 SOUTH TO 900 SOUTH			0						
		Bond Alternativ	WAKARA WAY - FOOTHILL DRIVE TO CHIPETA WAY			0						
						$ 1,520,406	$ 8,600,000	$ 3,625,000	$ 3,050,000	$ 5,800,000	$ 3,200,000	$ 2,500,000
			PUBLIC UTILITY DEFINED PROJECTS									
	534701008	2016-1200	CLEAN OUT REHABILITATION 2018/19	4	5	75,000	100,000	100,000	100,000	100,000	100,000	
10301	53470977		NORTHWEST DRAIN - IMPROVE BOOM DEPLOYMENT LOCATION AT BOY SCOUT DRIVE	5	3	15,000						
10301		2016-1270	URBAN WETLAND TREATMENT FACILITY AT FAIRMONT PARK - PRE-DESIGN	3	0	0		20,000				
10301		2016-0854	GREEN INFRASTRUCTURE AT HOOTEN BUILDING -ROOF DRAIN INFILTRATION	2	0	0	10,000	30,000				
10301	53470973	2016-1086	STORM WATER QUALITY - DESIGN FOR MAJOR OUTFALLS	3	0	100,000	100,000	100,000				
10301		2015-0132	WQ - WETLANDS TREATMENT FACILITY AT BOY SCOUT DRIVE	1	0	0						1,000,000
						$ 190,000	$ 210,000	$ 250,000	$ 100,000	$ 100,000	$ 100,000	$ 1,000,000
			RIPARIAN CORRIDOR PROJECTS									
10301	534926		EMIGRATION IMPROVEMENTS @ BONNEVILLE GOLF COURSE R03A,RO3B,RO4,RO5A,R05B	4	4	9,459						
10301	53473027	2015-0138	WQ - ROTARY PARK RCO IMPROVEMENTS AND WATER QUALITY FEATURE	4	3	0		250,000				
	STW-1		LEM_R02B , LOWER HOGLE ZOO	3	4	0		25,000	300,000			
10301	534922	2015-0581	LRB_L05A: VA MEDICAL CENTER – BELOW FOOTHILL DRIVE	2	4	0						121,000
10301	534912	2015-0560	UCC_R11C: GUARD SHACK GATE AREA	2	4	0						195,000
10301	534920	2015-0556	UCC_R11A: ELBOW TURN	2	4	0						80,000
10301	534910	2015-0559	LCC_R01B: UPPER FREEDOM TRAIL AREA	2	4	0						164,500
10301	534911	2015-0557	LCC_R01C: LOWER FREEDOM TRAIL AREA	2	4	0						150,000
10301	534918	2015-0578	LCC_R01D02A: UPPER MEMORY GROVE PARK	2	4	0						180,000
10301	534919	2015-0579	LRB_R03: UNIVERSITY – ABOVE CHIPETA WAY	2	4	0						85,000
10301	534923	2015-0582	LRB_R02: UNIVERSITY – BELOW RED BUTTE GARDEN	2	4	0						85,000
10301		2015-0580	UEM_R17: ABOVE DEBRIS BASIN (ROTARY PARK)	2	4	0						10,000
10301		2015-0577	LPC_R05C: MIDDLE SUGARHOUSE PARK	2	4	0						250,000

STORMWATER CIP BUDGET
Five Year Projected Budget FY2020 -2024

COST CENTER	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	CRITICALITY RATING	CONDITION RATING	PAST YEAR 2018-19 (Calc'd from P6)	BUDGET YEAR 2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
10301		2015-0576	LPC_R05B: SUGARHOUSE PARK – HEAR HIGHLAND HIGH TRACK	2	4	0						130,000
10301		2015-0575	LPC_R05A: UPPER SUGARHOUSE PARK	2	4	0						160,000
10301		2016-1201	1700 SOUTH STORM WATER TREATMENT FACILITY	3	0	0			250,000			250,000
10301	53471050	2015-0141	WQ - 10TH NORTH LIFT STATION WATER QUALITY IMPROVEMENTS	5	0	88,652	1,700,000					
10301		2015-0136	LRB_R05C; SUNNYSIDE PARK	1	1	0						173,000
10301		2015-0610	RED BUTTE AT 1300 EAST - RIPARIAN ENHANCEMENTS	2	0	0						10,000
10301	534928	2015-0721	RIPARIAN CORRIDOR SIGNS	2	0	0						50,000
10301		2015-0466	LEM_R03A: BONNEVILLE GOLF COURSE - UPPER	3	3	0						127,000
10301		2015-0467	LEM_R04: BONNEVILLE GOLF COURSE - BELOW STORM DRAIN OUTLET GULLY	3	3	0						200,000
10301		2015-0558	LEM_R01: ROTARY GLEN PARK	2	4	0						16,000
10301		2017-2085	CORNELL LIFT STATION WATER QUALITY IMPROVEMENTS - CONSTRUCTION	2	0	0						700,000
						$ 98,111	$ 1,700,000	$ 275,000	$ 550,000	$ -	$ -	$ 3,136,500
			LOCAL AREA PROJECTS (* WORK BY CITY CREWS)									
10301	534701007	2015-0437	VARIOUS PROJECTS	5	5	100,000	100,000	100,000	100,000	200,000	200,000	
10301	534701006	2015-0439	AVENUE CROSSWALKS / SID VARIOUS STREETS -DIP STONE REPLACEMENT	3	4	50,000	50,000	50,000	50,000	50,000	50,000	
10301	534701005	2015-0440	AVENUE CROSSWALKS AND ADA RAMPS	3	0	50,000	50,000	50,000	50,000	50,000	50,000	
10301	534701004	2015-0438	CONTRIBUTIONS BY DEVELOPERS	3	0	400,000	400,000	400,000	400,000	400,000	400,000	
	53475005		STORM DRAIN BOX DECK REPLACEMENT 2017/2018			79,385						
						$ 679,385	$ 600,000	$ 600,000	$ 600,000	$ 700,000	$ 700,000	$ -
			MASTER PLAN PROJECTS									
		2016-0776	MP35 CULVERT UPGRADES	3	5	0						190,400
		2016-0979	NORTH JOHN GLENN NEW 48 " LINE	4	4	0						3,480,000
		2016-1195	BECK STREET TRUCK REPLACEMENT FROM 200 SOUTH AND 300 WEST TO STATE STREET AND 500 SOUTH	4	3	0						5,449,951
		2016-0758	MP2 FOOTHILL CULVERT - EMIGRATION CREEK AT 2100 EAST	3	3	0						3,000
		2016-0800	MP66 PIPE UPSIZE	3	3	0						16,200
		2016-0788	MP51 EMIGRATION CREEK CHANNEL	3	3	0						22,000
		2016-0789	MP52 NEW 1700 EAST STORM DRAIN	3	3	0						31,000
		2016-0796	MP60 NEW PIPE AND OUTFALL	3	3	0						32,300
		2016-0770	MP21 200 GATSBY POWER PLANT	3	3	0						42,000
		2016-0759	MP3 SUGARHOUSE PARK TELEMETRY	3	3	0						50,000
		2016-0760	MP6 1700 S DETENTION BASIN TELEMETRY	3	3	0						50,000
		2016-0797	MP62 WYOMING STORM DRAIN	3	3	0						51,000
		2016-0805	MP75 PIPE UPSIZE	3	3	0						57,900
		2016-0798	MP63 PIPE UPSIZE	3	3	0						63,200
		2016-0809	MP82 400 SOUTH UPSIZE	3	3	0						63,800
		2016-0801	MP67 PIPE CAPACITY UPGRADES	3	3	0						85,800
		2016-0811	MP84 PIPE UPSIZE	3	3	0						94,200
		2016-0795	MP59 I-80/I-215 DETENTION BASIN	3	3	0						95,000
		2016-0814	MP88 NEW STORM DRAIN COLLECTOR	3	3	0						112,488
		2016-0799	MP64 PIPE UPSIZE	3	3	0						131,700
		2016-0807	MP78 PIPE UPSIZE	3	3	0						170,000
		2016-0784	MP46 SOUTH TEMPLE/FOLSOM AVENUE STREET RECONSTRUCTION	3	3	0						178,000
		2016-0802	MP69 PIPE UPSIZE	3	3	0						198,200
		2016-0806	MP76 NEW STORM DRAIN COLLECTOR	3	3	0						219,785
		2016-0787	MP50 9TH AVENUE STORM DRAIN	3	3	0						267,000
		2016-0808	MP79 WASATCH DRIVE IMPROVEMENTS	3	3	0						173,000

STORMWATER CIP BUDGET
Five Year Projected Budget FY2020 -2024

COST CENTER	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	CRITICALITY RATING	CONDITION RATING	PAST YEAR 2018-19 (Calc'd from P6)	BUDGET YEAR 2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
		2016-0780	MP39 NEW DETENTION BASIN	3	3	0						225,100
		2016-0815	MP89 NEW STORM DRAIN COLLECTOR	3	3	0						243,348
		2016-0782	MP42 REDWOOD ROAD AND CWA NO. 4	3	3	0						321,100
		2016-0777	MP36 LEE DRAIN IMPROVEMENTS	3	3	0						333,200
		2016-0771	MP24 200 EAST IMPROVEMENTS	3	3	0						333,548
		2016-0812	MP85 PIPE UPSIZE	3	3	0						360,300
		2016-0761	MP7 400 SOUTH PUMP STATION	3	3	0						378,500
		2016-0804	MP74 PIPE UPSIZE	3	3	0						387,000
		2016-0765	MP15 LIBERTY PARK DETENTION BASIN	3	3	0						391,899
		2016-0793	MP57 BRIGHTON DRAIN CHANNEL IMPROVEMENTS	3	3	0						452,200
		2016-0769	MP20 DETENTION BASIN - 800 SOUTH 4050 WEST	3	3	0						455,000
		2016-0810	MP83 LAURELHURST DRIVE IMPROVEMENTS	3	3	0						501,000
		2016-0773	MP28 I STREET CONDUIT	3	3	0						502,986
		2016-0772	MP27 BRIGHTON DRAIN CHANNEL IMPROVEMENTS	3	3	0						561,400
		2016-0778	MP37 NEW CHANNEL AND DETENTION BASIN	3	3	0						609,000
		2016-0786	MP49 500 SOUTH IMPROVEMENTS	3	3	0						635,592
		2016-0767	MP17 DETENTION BASIN AND CHANNEL	3	3	0						714,000
		2016-0766	MP16 CHANNEL TO I-80 INTERCHANGE	3	3	0						718,200
		2016-0791	MP54 CWA NO. 4 (1400 WEST) AT 200 SOUTH	3	3	0						728,900
		2016-0794	MP58 LEE DRAIN IMPROVEMENTS	3	3	0						729,400
		2016-0790	MP53 FOOTHILL DRIVE STORM DRAIN	3	3	0						774,000
		2016-0779	MP38 LEE DRAIN IMPROVEMENTS	3	3	0						778,600
		2016-0762	MP11 DETENTION BASIN OVERFLOW	3	3	0						807,300
		2016-0803	MP71 INTERSECTION CROSS DRAIN UPGRADES	3	3	0						1,065,000
		2016-0781	MP40 EAST BENCH AND FEDERAL HEIGHTS IMPROVEMENTS	3	3	0						1,152,532
		2016-0813	MP87 CWA NO. 1 IMPROVEMENTS	3	3	0						1,287,200
		2016-0764	MP13 EMIGRATION CONDUIT	3	3	0						1,308,000
		2016-0768	MP18 UNDERSIZED CULVERTS, CHANNEL IMPROVEMENTS, DETENTION BASIN	3	3	0						1,352,600
		2016-0785	MP47 PIPELINE FROM BECK STREET	3	3	0						1,693,643
		2016-0783	MP44 CWA NO. 2 AT I-80 NORTH TEMPLE OFF RAMP/AIRPORT DETENTION BASIN	3	3	0						2,031,000
		2016-0774	MP29 VARIOUS IMPROVEMENTS	3	3	0						2,114,200
		2016-0775	MP32 600 EAST CONDUIT	3	3	0						2,540,522
		2016-0763	MP12 900 SOUTH CONDUIT	3	3	0						12,626,142
		2016-0757	MP1 UPPER DRY CREEK DETENTION BASIN	3	0	0						616,000
						$ -	$ -	$ -	$ -	$ -	$ -	$51,056,336
			TOTAL COLLECTION LINES			$ 3,498,941	$12,530,000	$6,880,000	$4,321,000	$6,973,000	$4,300,000	$77,549,636
	2730.20		**LANDSCAPING**									
10301	53470934		NORTHWEST OIL DRAIN			0	150,000					
						$ -	$ 150,000	$ -	$ -	$ -	$ -	$ -
			TOTAL CAPITAL IMPROVEMENTS			$ 3,783,053	$12,744,000	$7,630,000	$4,371,000	$7,023,000	$4,300,000	$78,215,136

STORMWATER UTILITY CAPITAL PURCHASES BUDGET
Five Year Projected Budget FY2020-2024

COST CENTER	OBJECT CODE	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	Comments	CRITICALITY RATING	CONDITION RATING	PAST YEAR 2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
53-10201	2710.10			LAND										
								$ -	$ -	$ -	$ -	$ -		$ -
								0	0	0	0			0
	2750.10			MOTIVE REPLACEMENT AUTO & TRUCK										
				VARIOUS						400,000	400,000	400,000	400,000	
5310701	2750.10			3/4 TON TRUCK EXTENDED CAB WITH CABIN CHASSIS 4X4										
5310201	2750.10			3/4 TON TRUCK 4X4										
5310701	2750.10			3/4 TON W/UTILITY BED 4X4										
5310701	2750.10			3/4 TON W/UTILITY BED 4X4`				28,961						
5310201	2750.10		36840	FORD 1 TON CAB-N-CHASSIS WITH DUMP BED				28,961						
5310201	2750.10		36900	GMC 3/4 TON 4WD PICK-UP				34,498						
5310201	2750.10		33520	ESCAPE SUV				23,500						
5310201	2750.10			CLUB CAR CARRY ALL 500 (4)				52,632						
5310201	2750.10			10 WHEEL DUMP TRUCK										
5310301	2750.10			CHEV OR SIMILAR MID-SIZED 4X4 PICK UP W/BED COVER	Jason				30,000					
5310201	2750.10		36010	Replace Mack GU713	Randy				455,149					
5310201	2750.10		36080	Replace Ford F250 W/Dump Bed	Randy				41,500					
5310201	2750.10		36150	Replace Mack Granite	Randy				146,000					
								$ 168,552	$ 672,649	$ 400,000	$ 400,000	$ 400,000	$ 400,000	$ -
	2750.30			FIELD MAINTENANCE EQUIPMENT										
				VARIOUS						180,000	180,000	180,000	180,000	
5310201				VACTOR TRUCK				200,000						
5310201				75618000 6"-18" IPS BUTT FUSION MACHINE GAS HIGH FRC CYL (lincludes insert)				52,068						
5310201				CM-958H SED CEMENT MIXER 9 CF HONDA ENGINE				5,597						
5310201				SAND MASTER (SAND BAGGER)				12,241						
5310201				LOAD KING TRAILER 55 TON				69,260						
				CATERPILLAR 420F2 BACKHOE										
				SELF PROPELLED PIPE FUSION MACHINE										
5310201				BACKHOE BUYBACK PROGRAM				9,000						
5310201				TRACK EXCAVATOR W/DOZER BLADE (REPLACE 36870)										
5310201			NEW	LINKBILT AMI 54" ROOT RAKE	Randy				7,000					
5310201			NEW	HAULING PIPE	Randy				8,500					
								$ 348,166	$ 15,500	$ 180,000	$ 180,000	$ 180,000	$ 180,000	$ -
	2760.30			TELEMETERING										
5310201				RADIO REPLACEMENT				40,086						
5310201				VARIOUS				5,000	40,000	40,000	40,000	40,000	40,000	
								$ 45,086	$ 40,000	$ 40,000	$ 40,000	$ 40,000	$ 40,000	$ -
	2760.50			OFFICE EQUIPMENT										
								$ -	$ -	$ -	$ -	$ -		$ -
	2760.90			OTHER EQUIPMENT										
5310201				ENCLOSED TRAILER										
5310201				DUEL REEL AIR COMPRESSOR										
5310201				2 ECO FRIENDLY PUMPS										
5310201				3 AUTOMATIC COMPOSITE SAMPLERS										
5310201				VARIOUS				5,000						
5310201				CEMENT MIXER										
5310201				JETSCAN VIDEO NOZZLE										
5310201				HERBICIDE SPRAYER PUMP SYSTEM										
5310201				60" ROTARY EXCAVATOR MOWER COMPLETE										
								$ 5,000	$ -	$ -	$ -	$ -	$ -	$ -

STORMWATER UTILITY CAPITAL PURCHASES BUDGET
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COST CENTER	OBJECT CODE	PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	Comments	CRITICALITY RATING	CONDITION RATING	PAST YEAR 2018-19	2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
				TOTAL CAPITAL OUTLAY				$ 566,804	$ 728,149	$ 620,000	$ 620,000	$ 620,000	$ 620,000	$ -

Street Lighting Utility- Budget Summary and Cash Flow

STREET LIGHTING UTILITY
ENTERPRISE FUND
BUDGET SUMMARY
FY 2020-2022

SOURCES	ACTUAL 2017-18	AMENDED BUDGET 2018-19	PROJECTED ACTUAL 2018-19	PROPOSED BUDGET 2019-20	FORECAST BUDGET 2020-21	FORECAST BUDGET 2021-22
REVENUES						
STREET LIGHTING FEES	$ 4,198,227	$ 4,170,000	$ 4,198,227	**$ 4,198,227**	$ 4,198,227	$ 4,198,227
INTEREST INCOME	94,979	52,000	52,000	**30,000**	29,000	29,000
OTHER REVENUES	2,991	9,000	11,000	**9,000**	9,000	9,000
TOTAL REVENUES	$ 4,296,197	$ 4,231,000	$ 4,261,227	**$ 4,237,227**	$ 4,236,227	$ 4,236,227
OTHER SOURCES						
GRANTS & OTHER RELATED REVENUES	195,808	-	-	**-**	-	-
TRANSFERS FROM GENERAL FUND	20,000	20,000	20,000	**20,000**	20,000	20,000
IMPACT FEES	-	-	-	**-**	-	-
BOND PROCEEDS	-	-	-	**-**	-	-
T O T A L OTHER SOURCES	215,808	20,000	20,000	**20,000**	20,000	20,000
T O T A L SOURCES	$ 4,512,005	$ 4,251,000	$ 4,281,227	**$ 4,257,227**	$ 4,256,227	$ 4,256,227
EXPENSES & OTHER USES						
EXPENDITURES						
PERSONNEL SERVICES	$ 206,367	$ 198,307	$ 198,307	**$ 281,575**	$ 292,836	$ 304,548
OPERATING & MAINTENANCE	462	7,300	7,300	**7,300**	7,446	7,596
TRAVEL & TRAINING	1,368	3,000	3,000	**3,000**	3,060	3,121
UTILITIES	850,841	990,900	990,900	**1,010,900**	970,422	937,223
TECHNICAL SERVICES	1,035,264	1,720,028	1,720,028	**1,638,204**	1,523,964	1,503,287
DATA PROCESSING	1,117	-	-	**-**	-	-
FLEET MAINTENANCE	-	-	-	**-**	-	-
ADMINISTRATIVE SERVICE FEE	32,450	20,000	20,000	**20,000**	20,400	20,808
PAYMENT IN LIEU OF TAXES	-	-	-	**-**	-	-
RISK MANAGEMENT	-	-	-	**-**	-	-
TRANSFERS TO GENERAL FUND	-	-	-	**-**	-	-
OTHER CHARGES AND SERVICES	14,017	2,406	2,406	**2,298**	2,613	2,665
TOTAL EXPENDITURES	2,141,886	2,941,941	2,941,941	**2,963,277**	2,820,741	2,779,248
OTHER USES						
CAPITAL OUTLAY	-	-	-	**-**	-	-
CAPITAL IMPROVEMENT BUDGET	1,898,666	2,621,414	2,605,000	**1,725,000**	2,360,000	2,025,000
DEBT SERVICES	105,927	103,000	103,000	**103,000**	191,000	190,000
T O T A L OTHER USES	$ 2,004,593	$ 2,724,414	$ 2,708,000	**$ 1,828,000**	$ 2,551,000	$ 2,215,000
T O T A L USES	$ 4,146,479	$ 5,666,355	$ 5,649,941	**$ 4,791,277**	$ 5,371,741	$ 4,994,248
EXCESS REVENUE AND OTHER SOURCES OVER (UNDER) USES	$ 365,526	$ (1,415,355)	$ (1,368,714)	**$ (534,050)**	$ (1,115,514)	$ (738,021)
OPERATING CASH BALANCES						
BEGINNING JULY 1	$ 5,472,718	$ 5,838,244	$ 5,838,244	**$ 4,469,530**	$ 3,935,480	$ 2,819,966
ENDING JUNE 30	$ 5,838,244	$ 4,422,889	$ 4,469,530	**$ 3,935,480**	$ 2,819,966	$ 2,081,945
Cash Reserve Ratio	273%	150%	152%	132.8%	100.0%	74.9%

Cash reserve goal above 10%

STREET LIGHTING UTILITY
CASH FLOW
FY 2020 BUDGET
AND FY 2021-2024 FORECAST

	Actual YEAR 2017-2018	Projected YEAR 2018-2019	BUDGET YEAR 2019-2020	BUDGET YEAR 2020-2021	BUDGET YEAR 2021-2022	BUDGET YEAR 2022-2023	BUDGET YEAR 2023-2024
STREET LIGHTING SALES	4,198,227	4,198,227	4,198,227	4,198,227	4,198,227	4,198,227	4,198,227
OTHER INCOME	2,991	11,000	9,000	9,000	9,000	9,000	9,000
INTEREST INCOME	94,979	52,000	30,000	29,000	29,000	29,000	29,000
OPERATING INCOME	4,296,197	4,261,227	4,237,227	4,236,227	4,236,227	4,236,227	4,236,227
OPERATING EXPENSES	(2,141,886)	(2,941,941)	(2,963,277)	(2,820,741)	(2,779,248)	(2,840,922)	(2,904,074)
NET INCOME EXCLUDING DEP.	2,154,311	1,319,286	1,273,950	1,415,486	1,456,979	1,395,305	1,332,153
BOND PROCEEDS	-	-	-	-	-	-	-
OTHER CONTRIBUTIONS	215,808	20,000	20,000	20,000	20,000	20,000	20,000
CAPITAL OUTLAY	-	-	-	-	-	-	-
DEBT SERVICE	(105,927)	(103,000)	(103,000)	(191,000)	(190,000)	(190,000)	(190,000)
OTHER INCOME & EXPENSE	109,881	(83,000)	(83,000)	(171,000)	(170,000)	(170,000)	(170,000)
GENERATED FOR CAPITAL	2,264,192	1,236,286	1,190,950	1,244,486	1,286,979	1,225,305	1,162,153
CAPITAL IMPROVEMENTS	(1,898,666)	(2,605,000)	(1,725,000)	(2,360,000)	(2,025,000)	(2,025,000)	(1,525,000)
BEGINING CASH BALANCE	5,472,718	5,838,244	4,469,530	3,935,480	2,819,966	2,081,945	1,282,250
CASH INCREASE/(DECREASE)	365,526	(1,368,714)	(534,050)	(1,115,514)	(738,021)	(799,695)	(362,847)
ENDING BALANCE	5,838,244	4,469,530	3,935,480	2,819,966	2,081,945	1,282,250	919,403
RATE CHANGE	0%	0%	0%	0%	0%	0%	0%
Cash Reserve Ratio	272.6%	151.9%	132.8%	100.0%	74.9%	45.1%	31.7%
Debt Service Coverage	20.34	12.81	12.37	7.41	7.67	7.34	7.01
DEBT SERVICE % OF GROSS OP. REV.	2.5%	2.4%	2.4%	4.5%	4.5%	4.5%	4.5%
RESIDENTIAL BILL OF 1 ERU (or 75 ft)	3.73	3.73	3.73	3.73	3.73	3.73	3.73

STREET LIGHTING UTILITY
CIP BUDGET
Five Year Projected Budget 2020-2024

COST CENTER	PROJECT NUMBER	PROJECT DESCRIPTION	CRITICALITY RATING	CONDITION RATING	PAST YEAR SPENT 2018-19	BUDGET YEAR 2019-20	2020-21	2021-22	2022-23	2023-24	DELAYED
48-48001	2730.80	**Base Level Projects**									
48001	48135	ARTERIAL & COLLECTOR STREET HE AND SYSTEM UPGRADES	2	4	300,000	300,000	300,000	300,000	300,000		
48001	48126	HIGH WATTAGE REPLACEMENTS				500,000	500,000	500,000	500,000	500,000	2,500,000
48001	48130	NEIGHBORHOOD HE AND SYSTEM UPGRADES	4	4	1,000,000	500,000	500,000	500,000	500,000	500,000	2,500,000
48001	48137	1300 EAST - STREET LIGHTS	3	3							
48001		LOCAL STREET IMPROVEMENT SUPPORT			50,000	200,000	200,000	200,000	200,000	200,000	1,000,000
		LIGHTING CONTROLS				200,000	500,000	500,000	500,000	300,000	
		BASE LEVEL - TOTAL IMPROVEMENTS			$ 1,350,000	$ 1,700,000	$ 2,000,000	$ 2,000,000	$ 2,000,000	$ 1,500,000	$ 6,000,000
48-48101	2730.80	**TIER 1 Projects**									
48101	48131	Tier 1 Capital Replacements			5,000	5,000	5,000	5,000	5,000	5,000	595,000
48101		Tier 1 HE Upgrades					190,000				210,000
		TIER 1 - TOTAL IMPROVEMENTS			$ 5,000	$ 5,000	$ 195,000	$ 5,000	$ 5,000	$ 5,000	$ 805,000
48-48201	2730.80	**TIER 2 Projects**									
48201	48132	Tier 2 Bad Wiring Replacement			365,000						
48201	48139	Tier 2 Capital Replacement			5,000	5,000	5,000	5,000	5,000	5,000	395,000
48201	48133	Tier 2 HE Upgrades			100,000						
		TIER 2 - TOTAL IMPROVEMENTS			$ 470,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 5,000	$ 395,000
48-48301	2730.80	**TIER 3 Projects**									
48301	48140	Tier 3 Capital Replacement			15,000	15,000	15,000	15,000	15,000	15,000	2,310,000
48301	48134	Tier 3 HE Upgrades			765,000		145,000				160,000
		TIER 3 - TOTAL IMPROVEMENTS			$ 780,000	$ 15,000	$ 160,000	$ 15,000	$ 15,000	$ 15,000	$ 2,470,000
		TOTAL CAPITAL IMPROVEMENTS			$ 2,605,000	$ 1,725,000	$ 2,360,000	$ 2,025,000	$ 2,025,000	$ 1,525,000	$ 9,670,000

APPENDIX A: Proposed Rate Structure and WRF Resolutions

APPENDIX B: Rationale for New Positions

Proposed New Public Utilities Positions and Organizational Changes for FY 2020 (in alphabetical order)

Community and Engagement (one FTE and Organization Change)

The Department has identified a need for one full time employee to assist with public engagement. This position, Community and Engagement Coordinator, would report to the Community and Engagement Manager, and support all print and television media needs, website, and social media functions. The position would also assist with community feedback and education on the Department's numerous programs, planning efforts, and capital improvement projects. Engagement related to planning and programmatic work includes watershed, water conservation, street lighting, and stormwater master planning. In addition, construction related to large capital projects, such as those related to the new WRF, the East-West Conveyance, and streets bond-related projects will have an impact on the community and require additional engagement.

The Department is proposing to move the Employee Development and Training Coordinator position to report to the Community and Engagement Manager. The Employee Development and Training Coordinator position currently reports to the Department Director.

The Department is proposing to reclassify the Community and Engagement Manager to a slightly higher pay classification to reflect additional management responsibility.

Development Services (one FTE)

The Department has identified the need for a dedicated records technician in the Department's Development Services division. This is due to increased growth throughout the Department's service area, including within Salt Lake City, Cottonwood Heights, Mill Creek, and Holladay. This position will report to the Water Rights, Contracts, and Property Manager, and be responsible for maintaining and updating electronic files, including agreements, plans, general correspondence, and general administration files. This position will also assist with succession planning due to anticipated retirements in this area.

Engineering (five FTEs)

See attached memorandum dated March 20, 2019 from Jason Brown, Chief Engineer to Laura Briefer, Director of Public Utilities.

GIS Leak Detection (one FTE)

The Department has identified a need to add one FTE to support the Department's leak detection program. Currently there is only one position allocated to this task, and therefore no redundancy in this function. The leak detection function allows the Department to identify water loss caused by leaks in the water distribution system. Leaks in the system lead to water waste and lost revenue.

Maintenance and Operations (one FTE)

The Department has identified the need for an additional Senior Water System Maintenance Worker. This position was approved in the Department's FY2019 budget.

However, the Department reclassified this position as a Maintenance Electrician IV in order to address a safety need for our emergency water crews. The Department is in a several year process of converting more than 90,000 water meters in to smart meters across the water service area. The Senior Water System Maintenance Worker is needed specifically to change large meters for industry, business, and institutional properties. This position also supports succession planning in the Maintenance and Operations Division. This employee will report to the Water System Maintenance Supervisors who will report to the Water Distribution System Manager.

Special Projects Manager Reclassification and Water Resources Reorganization

The Department is proposing to reclassify the Special Projects Manager position to a Water Resources Manager position and create a Water Resources Division. The Water Resources Division will be responsible for administering the City's water rights, maintaining water supply and demand data, climate and energy initiatives, and water conservation programs. The Water Resources Manager will report to the Department Director, and oversee the Sustainability, Water Conservation, and Hydrology functions. The purpose of this change is to increase capacity to better address and coordinate recommended actions identified in the Department's updated Water Supply and Demand Plan, Drought Contingency Plan, and Water Conservation Plan. In addition, the state has increased reporting requirements related to water rights, water source sizing, and water loss, which this position and division will manage. Finally, this reorganization facilitates succession planning.

Sustainability (one FTE)

The Department has identified a need for one full time employee to assist with energy management, energy and greenhouse gas reduction, and climate change projects. This position will report to the Water Resources Manager. This Sustainability Manager position is needed to ensure compliance with City energy initiatives and assist the Department with its climate change vulnerability assessments, mitigation, and adaptation planning. This includes the following:

- **The Comprehensive Energy Management Executive Order**: This City Executive Order requires that the Department prepare and implement energy management plans, and places requirements on renovation and new construction of the Department's facilities: http://www.slcinfobase.com/PPAREO/#!WordDocuments/comprehensiveenergymanagementofsaltlakecityfacilities.htm.
- **The Elevate Buildings Commercial Ordinance (Section 18.94.050)**: This City ordinance requires that the Department prepare and submit energy benchmarking information to the Sustainability Department and to the public: http://sterlingcodifiers.com/codebook/index.php?book_id=672&chapter_id=102505
- **Salt Lake City Department of Public Utilities Renewable Energy Plan (2015):** This plan identifies opportunities throughout the Department's infrastructure for the generation of renewable energy.
- **Salt Lake City Department of Public Utilities Wire to Water Efficiency Study (2018)**: This study identifies capital and operational actions that the Department can take to reduce energy use. *The Department has estimated that implementation*

of energy efficiency strategies identified in this study will result in a potential annual cost savings of $200,000, and 4,000,000 kilowatt hours.

- **Salt Lake City Department of Public Utilities Climate Change Vulnerability Assessment and Adaptation Plan (ongoing)**: The Department is in its second year of a five-year scientific study with the University of Utah to identify climate risks related to water supply, water quality, and storm intensification. The study will result in an adaptation plan to mitigate identified climate risks.

Wastewater Pretreatment Program (four FTEs)

The Department's Pretreatment Program is required by Section 403 of the Clean Water Act. The overall mission of the Pretreat Program is to provide protection to the Publicly Owned Treatment Works (POTW), protect the health and safety of collections and treatment staff and the environment from hazardous, toxic, and incompatible pollutant discharge into the sanitary sewer system and also promote the health and safety of the general public by minimizing the potential for sanitary sewer overflow events.

Four additional staff positions are requested for the Pretreatment Program:

- Fats, Oil, and Grease (FOG)/Sewer Rate Program Supervisor
- Pretreatment Inspector/Permit Writer
- Senior Wastewater Sampler/Inspector
- Administrative Assistant (WRF)

These positions are needed for the program to meet the demands of current city growth as well as planned industrial growth in the Northwest Quadrant. New federal wastewater discharge prohibitions have created additional work. Two recent regulatory examples relate to hazardous waste pharmaceuticals and dental amalgam. When compared to programs in cities of similar population and industrial influence, the Department's Pretreatment Program is understaffed. This shortfall was noted by the Utah Division of Water Quality (UDWQ) during their 2018 inspection. The UDWQ inspection findings report stated: "*With the growth of the permitting load and the dental program it is recommended that the city evaluate the need for additional staffing.*"

The FOG/Sewer Rate Program Supervisor will take a proactive role to reduce FOG loading into the collection system. Currently there are areas of the city the Collections team has to clean quarterly due to FOG buildup in the lines. The discharge of FOG material into the collection system can lead to sewer overflow and more rapid degradation of the collection system. The supervisor will also be tasked with ensuring sewer rates are properly assigned to commercial and industrial used based on pollutant loading.

Watershed Program (two Seasonal Positions)

The Department has identified the need for two seasonal watershed worker positions during the summer. Recreation continues to increase in the City's watersheds in City Creek, Parleys, Big Cottonwood, and Little Cottonwood Canyons. This is resulting in potential impacts to water quality. Seasonal watershed workers help with upkeep of restroom

facilities at popular trailheads, stewardship of the Department's preserved lands, and public education under the Keep it Pure program.

TO: Laura Briefer, Director of Public Utilities

BY: Jason Brown, P.E., Chief Engineer

DATE: March 20, 2019

SUBJECT: Request for five additional Engineering staff FTE's for fiscal year 2020

Background, Purpose and Need

The objective of this memorandum is to provide justification and recommendation for additional staff for the Engineering Division within Public Utilities.

The Engineering Division of the Department of Public Utilities has been going through dramatic changes in terms of updating our practices, organization, project elements, and work responsibilities to enhance our services for better accountability, performance, transparency, and efficiency in the delivery of engineering services to the Utility and the public. These changes coupled with changes in the industry have highlighted resource needs and workload stresses in our work environment that impede our ability and capacity for continued successful project delivery.

Summary

We present the following justifications for increasing the in-house staff FTE's for the Engineering group:

(1) The current and past CIP workload justifies more in-house staff.

In 1994 Hughes, Heiss & Associates conducted an audit of the Engineering group. They recommended increasing the staff based on the CIP program funding at that time and concluded that using Consultants to fill in the production gap was not "cost effective". At the time, a reorganization of Engineering was done but no additional staff was added.

The total CIP program for water/sewer/drainage in 1994 when the audit was conducted was under $10M. Currently it is over $170M and the number of FTE's has remained basically the same (Figure 1 & Figure 2). The demands on the current staff are increasing as public outreach, engagement and education are drawing away time that was typically allocated for design and construction. Many of these critical activities we have been able to temper with advances in efficiencies using technologies but even with advances with technology, the technology requires staff time.

(2) In-house staff is less expensive than using Consultants for the CIP workload.

The average cost of the existing Engineering staff including overhead (7.72%) and labor additive (56.36%) is $51.68 per hour. The average hourly cost which will be charged by Consultants for project engineers based on the most recent General Services SOQ's is approximately $150 per hour. Doing work with City staff is approximately a <u>third</u> of the cost of using a Consultant. With new staff positions being limited, we have utilized outside consultants for much of the additional inspection and design. This method allows staff to manage approximately 2 to 4 times the number of projects depending on complexity. However, the costs to design and inspect the projects are generally 3 times more expensive because of reasons stated above.

(3) Aging infrastructure requires additional staff to maintain cost effectiveness.

The CIP budget levels is projected to increase, particularly with the Water Reclamation Plant where a process upgrade project will be required to meet permit requirements for nutrient removal. The Nutrient project is projected to be $528 million over the next 7 years. The other programs (water/sewer/drainage/lighting) are also showing increased budget funding requirements due to aging infrastructure and regulatory requirements. Assuming 10% design/construction management cost and 30% vacation/sick/holiday discount, this CIP program will require 36 FTE's. The current staff level is 27.72 FTE's. The gap is currently being supplemented through consultant contracts, but as additional condition assessments have been completed, we are finding that the breadth of improvements necessary to maintain a high level of service to the community is expanding.

(4) To reduce inspector overtime.
The overtime cost for inspectors in 2018 was $137k. Converting this cost to full time FTE's equates to 1.5 additional inspector FTE.

<u>RECOMMENDATION</u>

We are requesting the addition 5 of FTE's to the Engineering group based on the analysis discuss above. Specifically, we are recommending the following changes to the staffing document as outlined below.

<u>New Staff Positions</u>

+3 E Tech II	E Tech II to support development in the Department service area, including Salt Lake County and the Northwest Quadrant.
Justification	Based on current workload needs to assist in the inspection and drafting. Roughly 1/3 the cost will be to have in-house inspection rather than consultant contracted inspection. This can become a cost savings for the Department. Having internal staff inspect infrastructure has the added benefit of knowledge retention within the department rather than the external consultant. In addition, many of the existing inspection staff are approaching retirement age and hiring newer staff is in line with succession planning within the department.
+2 Eng II/II	Project Engineer/Development Review Engineer
Justification	As with the inspectors having internal staff design, manage and review the upcoming CIP projects will benefit the department with reducing the costs associated with having external consultants design, manage and review. The additional staff will also tackle the projected workload, aging infrastructure and regulatory requirements.

Below are two figures illustrating the relative need and impact of the City's robust capital improvement program. These are anecdotal but support the business case and workplan justification described above.

NET CHANGE = +6 FTE by 5 new staff positions and reassignment of one staff position

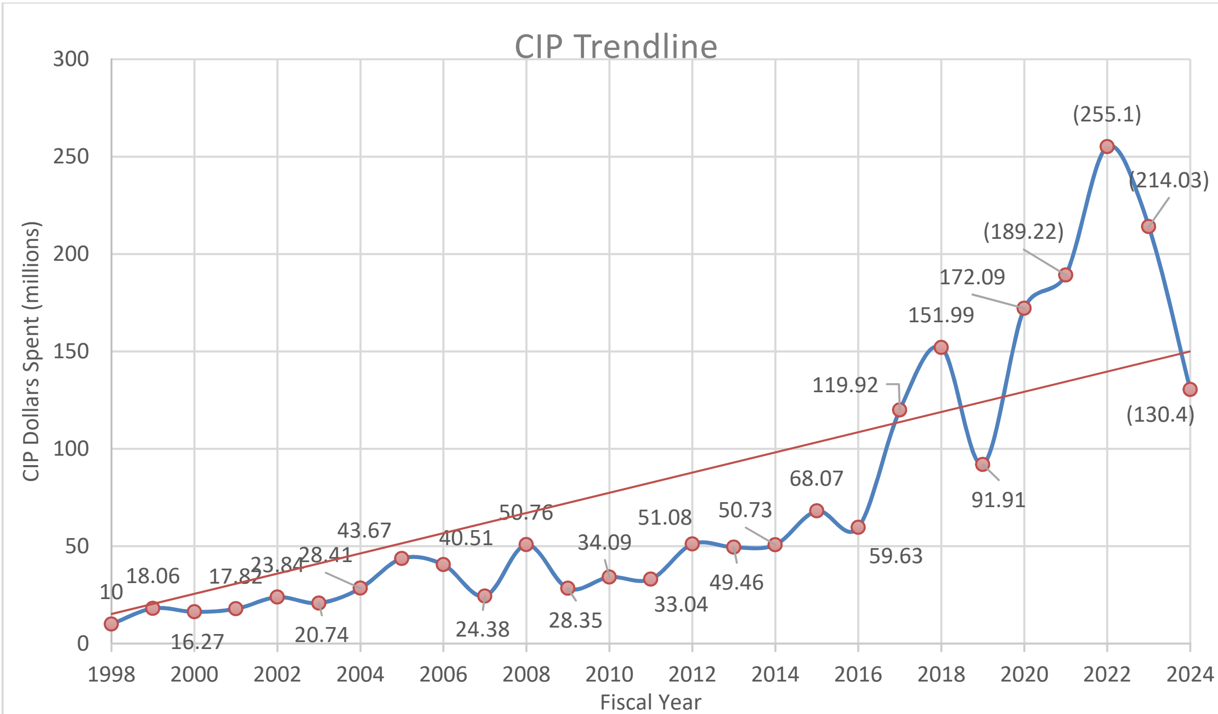


Figure 1 – CIP Trend line

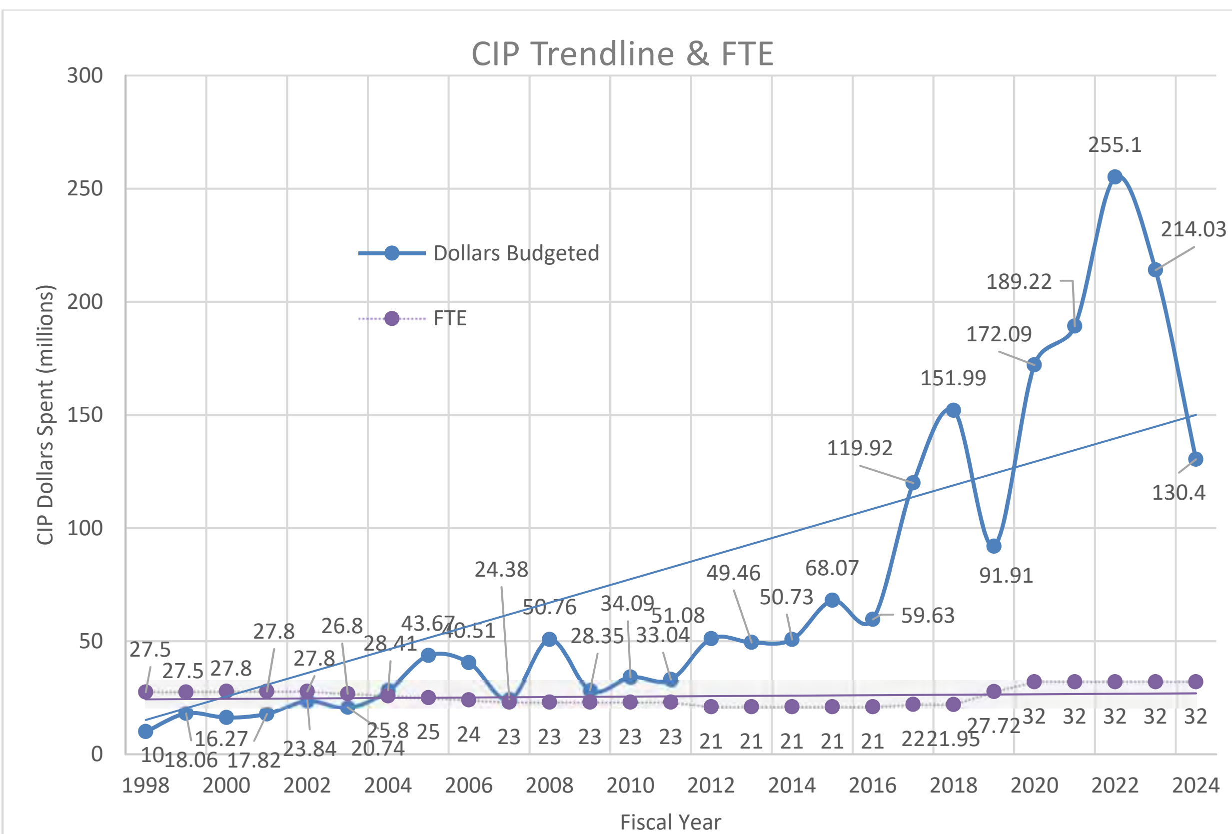


Figure 2 – CIP vs. Engineering group FTE staffing level

APPENDIX C: Public Utilities' Energy Management and Greenhouse Gas Mitigation Projects

Public Utilities Energy Management and Greenhouse Gas Mitigation Projects

Environmental sustainability is at the root of the Department of Public Utilities' legacy and public ethic. Indeed, the Department's mission statement is "serving our community, protecting our environment." The Department has been a steward of water resources serving the Salt Lake Valley for more than a century. Public Utilities later took on the role of protecting public health and the environment through wastewater treatment and stormwater systems and developing street lighting as a self-sustaining utility.

One major component of this legacy is actively addressing the Department's energy use and greenhouse gas emissions, as climate change will have significant implications for Public Utilities' capacity to provide water services to its customers. Mayor Biskupski requested each City Department include as part of its FY2020 budget a demonstrated reduction of greenhouse gas emissions. The Department is providing a summary of efforts identified in the recommended budget that will contribute to this goal.

There are several City policies and goals that drive the Department's efforts regarding energy efficiency, greenhouse gas reduction, and other sustainability practices. These policies include:

- Comprehensive Energy Management of Salt Lake City Facilities Executive Order
- LEED Design Standards Executive Order
- Net-Zero Energy Buildings Executive Order
- Climate Positive 2040
- Elevate Buildings Ordinance

In addition to these governing City policies, the Department has also developed a Public Utilities Energy Policy to guide energy efficiency efforts for all operations and capital projects:

> *SLCDPU uses energy wisely while continuing to exceed the expectations of those we serve. We implement prudent and environmentally responsible strategies and programs in our facilities and operations that minimize our energy use without sacrificing service reliability.*

The FY2020 recommended budget includes funding, both operational and capital, for several efforts that support the Department's Energy Policy and various City goals, ordinances, and Executive Orders. These projects have been identified in the Capital Plans for all enterprise funds. Each identified project has a sustainability component that will contribute to the fulfillment of the various requirements. Examples include:

- A Wire-to-Water Energy Efficiency Study was completed in January 2019 and identified an energy savings potential of 12%. This savings percentage translates to approximately $200,000 and 4,000,000 kWh per year with all capital and operation improvements identified and recommended in the study. Five key projects were identified in the study whose implementation would result in 2,600

metric tons per year of avoided carbon emissions at an initial capital cost of $2,525,000 with a 5.7-year payback period.

  - Select Sources According to Energy Requirements
  - Implement a Leak Detection Program
  - Preserve Pressure from Parley's Water Treatment Plant
  - Install Flow Meters at Pump Stations
  - Optimize the Military Pump Station

- Within the Water Utility, the major upgrade projects at each of the three drinking water treatment plants will consider energy efficiency, reduction of greenhouse gases, and compliance with all executive orders and initiatives. There are also several other Water Utility capital projects that will contribute to the Department's overall sustainability goals, including pump and motor upgrades, the AMI meter replacement program, and designated funding to address specific projects recommended in the Wire-To-Water Energy Efficiency Study. The Parley's Canyon hydropower project design is budgeted for FY 2020, with completion anticipated by 2022. At this time, it is anticipated the project will provide a renewable energy source that is anticipated to generate $126,600 per year in revenue.
- The Sewer Utility also includes several projects in the Capital Plan that will meet sustainability goals, including pump replacements, upgrades to existing reclamation facility, inflow and infiltration studies, and flow meter installation. Most significantly, the design of the new Water Reclamation Facility includes a Sustainability Task Force that is dedicated to the analysis and implementation of energy efficiency/greenhouse gas reduction improvements throughout the occupied buildings and process components of the plant.
- There are several lift station rehabilitation and abandonment projects identified in the Stormwater Capital Plan that will contribute to the achievement of sustainability goals. Rehabilitation projects may entirely replace the pumps and motors or significantly repair these components to reduce overall energy use of the lift station. The abandonment projects will remove a source of energy use altogether, again creating a positive effect on the Stormwater Utility's sustainability impact.
- The goal of the Street Lighting Utility is to have all street lights equipped with energy efficient technology by 2023. The Utility is on track to meet this goal. Data from 2018 indicates that more than 60% of street lights are energy efficient with approximately 3,580,650 kWh in savings since 2014. The high efficiency upgrade projects in the Capital Plan are planned solely to meet the energy efficiency goals for the Street Lighting Utility.

APPENDIX D: Rate Change Comparisons and Customer Impacts

Water Rate Change Comparisons

Comparison of Monthly Water Base Rate Options for City Customers

Meter Size (inches)	2019 Current Rate	2019 Rate Study	2020 Proposed Rate	Changes: Current to Rate Study $	Current to Rate Study %	Rate Study to Proposed $	Rate Study to Proposed %	Current to Proposed $	Current to Proposed %
3/4	9.89	8.84	9.28	-1.05	-11%	0.44	5%	-0.61	-6%
1	9.89	11.56	12.14	1.67	17%	0.58	5%	2.25	23%
1 1/2	11.68	18.37	19.29	6.69	57%	0.92	5%	7.61	65%
2	12.68	26.55	27.88	13.87	109%	1.33	5%	15.20	120%
3	21.28	48.34	50.76	27.06	127%	2.42	5%	29.48	139%
4	22.78	72.86	76.50	50.08	220%	3.64	5%	53.72	236%
6	32.89	140.98	148.03	108.09	329%	7.05	5%	115.14	350%
8	59.11	222.71	233.85	163.60	277%	11.14	5%	174.74	296%
10	109.63	576.91	605.76	467.28	426%	28.85	5%	496.13	453%

Comparison of Monthly Water Base Rate Options for County Customers

Meter Size (inches)	2019 Current Rate	2019 Rate Study	2020 Proposed Rate	Changes: Current to Rate Study $	Current to Rate Study %	Rate Study to Proposed $	Rate Study to Proposed %	Current to Proposed $	Current to Proposed %
3/4	13.35	11.93	12.53	-1.42	-11%	0.59	5%	-0.82	-6%
1	13.35	15.61	16.39	2.25	17%	0.78	5%	3.04	23%
1 1/2	15.77	24.80	26.04	9.03	57%	1.24	5%	10.27	65%
2	17.12	35.84	37.64	18.72	109%	1.80	5%	20.52	120%
3	28.73	65.26	68.53	36.53	127%	3.27	5%	39.80	139%
4	30.75	98.36	103.28	67.61	220%	4.91	5%	72.52	236%
6	44.40	190.32	199.84	145.92	329%	9.52	5%	155.44	350%
8	79.80	300.66	315.70	220.86	277%	15.04	5%	235.90	296%
10	148.00	778.83	817.78	630.83	426%	38.95	5%	669.78	453%

*Rate Study column is the Department's 2018 Comprehensive Water, Sewer and Stormwater Rate Study proposed change over the current rate column. The proposed rate is the proposed increase on top of the rate study rates

Comparison of Water Monthly Usage Rate Options for City Residential Customers

	2019	2019	2020	Changes					
Flat Rate or Block	Current Rate per ccf	Rate Study per ccf	Proposed Rate per ccf	Current to Rate Study		Rate Study to Proposed		Current to Proposed	
				$	%	$	%	$	%
Winter Rate Structure (November - March)									
Flat Rate	1.35	1.30	1.37	-0.05	-4%	0.07	5%	0.02	1%
Summer Rate Structure (April - October)									
Block 1	1.35	1.30	1.37	-0.05	-4%	0.07	5%	0.02	1%
Block 2	1.85	1.78	1.87	-0.07	-4%	0.09	5%	0.02	1%
Block 3	2.57	2.47	2.59	-0.10	-4%	0.12	5%	0.02	1%
Block 4	2.74	2.63	2.76	-0.11	-4%	0.13	5%	0.02	1%

Comparison of Water Monthly Usage Rate Options for County Residential Customers

	2019	2019	2020	Changes					
Flat Rate or Block	Current Rate per ccf	Rate Study per ccf	Proposed Rate per ccf	Current to Rate Study		Rate Study to Proposed		Current to Proposed	
				$	%	$	%	$	%
Winter Rate Structure (November - March)									
Flat Rate	1.82	1.76	1.84	-0.07	-4%	0.09	5%	0.02	1%
Summer Rate Structure (April - October)									
Block 1	1.82	1.76	1.84	-0.06	-3%	0.08	5%	0.02	1%
Block 2	2.50	2.40	2.52	-0.10	-4%	0.12	5%	0.02	1%
Block 3	3.47	3.33	3.50	-0.14	-4%	0.17	5%	0.03	1%
Block 4	3.70	3.55	3.73	-0.15	-4%	0.18	5%	0.03	1%

Rate Structure (Same for City and County)

Block	Current	Study	Proposed
Flat Rate	All Usage	All Usage	All Usage
Block 1	1 - 10 ccf	1 - 10 ccf	1 - 10 ccf
Block 2	11 - 30 ccf	11 - 30 ccf	11 - 30 ccf
Block 3	31 - 70 ccf	31 - 60 ccf	31 - 60 ccf
Block 4	>71 ccf	>61 ccf	>61 ccf

Comparison of Monthly Usage Rate Options
for City CII Customers

Flat Rate or Block	2019 Current Rate per ccf	2019 Rate Study per ccf	2020 Proposed Rate per ccf	Changes: Current to Rate Study $	%	Rate Study to Proposed $	%	Current to Proposed $	%
Winter Rate Structure (November - March)									
Flat Rate	1.35	1.42	1.49	0.07	5%	0.07	5%	0.14	10%
Summer Rate Structure (April - October)									
Block 1	1.35	1.42	1.49	0.07	5%	0.07	5%	0.14	10%
Block 2	1.85	1.94	2.04	0.09	5%	0.10	5%	0.19	10%
Block 3	2.57	2.70	2.84	0.13	5%	0.14	5%	0.27	11%
Block 4	2.47	2.87	3.01	0.40	16%	0.14	5%	0.54	22%

Comparison of Monthly Usage Rate Options
for County CII Customers

Flat Rate or Block	2019 Current Rate per ccf	2019 Rate Study per ccf	2020 Proposed Rate per ccf	Changes: Current to Rate Study $	%	Rate Study to Proposed $	%	Current to Proposed $	%
Winter Rate Structure (November - March)									
Flat Rate	1.82	1.92	2.01	0.09	5%	0.09	5%	0.19	10%
Summer Rate Structure (April - October)									
Block 1	1.82	1.92	2.01	0.09	5%	0.09	5%	0.19	10%
Block 2	2.50	2.62	2.75	0.12	5%	0.14	5%	0.26	10%
Block 3	3.47	3.65	3.83	0.18	5%	0.19	5%	0.36	11%
Block 4	3.33	3.87	4.06	0.54	16%	0.19	5%	0.73	22%

Rate Structure (Same for City and County)

Block	Current	Study	Proposed
Flat Rate	All Usage	All Usage	All Usage
Block 1	0-AWC	0-AWC	0-AWC
Block 2	AWC-300%	AWC-300%	AWC-300%
Block 3	300%-700%	300%-600%	300%-600%
Block 4	>700%	>600%	>600%

*CII= Commercial, Industrial, and Institutional
*AWC = Average Winter Consumption. "AWC-300%" means usage greater than a customer's AWC and less than or equal to

Comparison of Water Monthly Usage Rate Options
for City Irrigation Customers

Flat Rate or Block	2019 Current Rate per ccf	2019 Rate Study per ccf	2020 Proposed Rate per ccf	Changes: Current to Rate Study $	Current to Rate Study %	Rate Study to Proposed $	Rate Study to Proposed %	Current to Proposed $	Current to Proposed %
Winter Rate Structure (November - March)									
Flat Rate	1.85	1.71	1.80	-0.14	-8%	0.09	5%	-0.05	-3%
Summer Rate Structure (April - October)									
Block 1	1.85	1.71	1.80	-0.14	-8%	0.09	5%	-0.05	-3%
Block 2	2.57	2.38	2.50	-0.19	-7%	0.12	5%	-0.07	-3%
Block 3	2.74	2.53	2.66	-0.21	-8%	0.13	5%	-0.08	-3%

Comparison of Water Monthly Usage Rate Options
for County Irrigation Customers

Flat Rate or Block	2019 Current Rate per ccf	2019 Rate Study per ccf	2020 Proposed Rate per ccf	Changes: Current to Rate Study $	Current to Rate Study %	Rate Study to Proposed $	Rate Study to Proposed %	Current to Proposed $	Current to Proposed %
Winter Rate Structure (November - March)									
Flat Rate	2.50	2.31	2.42	-0.19	-8%	0.12	5%	-0.07	-3%
Summer Rate Structure (April - October)									
Block 1	2.50	2.31	2.42	-0.19	-8%	0.12	5%	-0.07	-3%
Block 2	3.47	3.21	3.37	-0.26	-7%	0.16	5%	-0.10	-3%
Block 3	3.70	3.42	3.59	-0.28	-8%	0.17	5%	-0.11	-3%

Rate Structure (Same for City and County)

Block	Current	Study	Proposed
Flat Rate	All Usage	All Usage	All Usage
Block 1	1CCF-Target Budget	1CCF-Target Budget	1CCF-Target Budget
Block 2	Target Budget up to 300% of Target Budget	Target Budget up to 300% of Target Budget	Target Budget up to 300% of Target Budget
Block 3	Over 300% of Target Budget	Over 300% of Target Budget	Over 300% of Target Budget

* "Target budget" means the estimated amount of water consumed per acre, as established by the Public Utilities Director or his/her designee each year for customer based on factors including, but not limited to, evapotranspiration, and considering efficient water practices. A different target budget is established for each month of the irrigation season.

Proposed Water Rate Change Customer Impacts

Water Rate Change
Annual Impact on Select City Customers

Account Type	Annual Usage	Meter Size	2019 Current Rate	2020 Proposed Rate	$ Change	% Change
Residential Minimum Use	72 ccf	3/4	215.88	210.00	(5.88)	-2.72%
Residential Low Use	96 ccf	3/4	248.28	242.88	(5.40)	-2.17%
Residential Medium Use	255 ccf	3/4	559.17	556.95	(2.22)	-0.40%
Residential High Use	838 ccf	1	1,973.18	2,016.94	43.76	2.22%
Industrial Use	96,476 ccf	2	140,552.76	151,270.96	10,718.20	7.63%
Commercial Use	11,597 ccf	2	16,365.71	17,684.93	1,319.22	8.06%

Water Rate Change
Monthly Impact on Select City Customers

Account Type	Monthly Usage	Meter Size	2019 Current Rate	2020 Proposed Rate	$ Change	% Change
Residential Minimum Use	6 ccf	3/4	17.99	17.50	(0.49)	-2.72%
Residential Low Use	8 ccf	3/4	20.69	20.24	(0.45)	-2.17%
Residential Medium Use	21 ccf	3/4	46.60	46.41	(0.18)	-0.40%
Residential High Use	70 ccf	1	164.43	168.08	3.65	2.22%
Industrial Use	8,040 ccf	2	11,712.73	12,605.91	893.18	7.63%
Commercial Use	966 ccf	2	1,363.81	1,473.74	109.94	8.06%

Water Rate Change
Annual Impact on Select County Customers

Account Type	Annual Usage	Meter Size	2019 Current Rate	2020 Proposed Rate	$ Change	% Change
Residential Minimum Use	72 ccf	3/4	291.44	283.50	(7.94)	-2.72%
Residential Low Use	96 ccf	3/4	335.18	327.89	(7.29)	-2.17%
Residential Medium Use	255 ccf	3/4	754.88	751.88	(3.00)	-0.40%
Residential High Use	838 ccf	1	2,663.79	2,722.87	59.08	2.22%
Industrial Use	96,476 ccf	2	189,746.23	204,215.80	14,469.57	7.63%
Commercial Use	11,597 ccf	2	22,093.71	23,874.66	1,780.95	8.06%

Water Rate Change
Monthly Impact on Select County Customers

Account Type	Monthly Usage	Meter Size	2019 Current Rate	2020 Proposed Rate	$ Change	% Change
Residential Minimum Use	6 ccf	3/4	24.29	23.63	(0.66)	-2.72%
Residential Low Use	8 ccf	3/4	27.93	27.32	(0.61)	-2.17%
Residential Medium Use	21 ccf	3/4	62.91	62.66	(0.25)	-0.40%
Residential High Use	70 ccf	1	221.98	226.91	4.92	2.22%
Industrial Use	8,040 ccf	2	15,812.19	17,017.98	1,205.80	7.63%
Commercial Use	966 ccf	2	1,841.14	1,989.55	148.41	8.06%

Sewer Rate Change Comparisons

Comparison of Monthly Sewer Class Rate Changes

Flow $ Per CCF

	2019	2019	2020	Changes					
Class	Current Rate	Rate Study	Proposed Rate	Current to Rate Study		Rate Study to Proposed		Current to Proposed	
				$	%	$	%	$	%
1	1.86	1.94	2.29	0.08	4%	0.35	18%	0.43	23%
2	1.86	1.94	2.29	0.08	4%	0.35	18%	0.43	23%
3	1.86	1.94	2.29	0.08	4%	0.35	18%	0.43	23%
4	1.86	1.94	2.29	0.08	4%	0.35	18%	0.43	23%
5	1.86	1.94	2.29	0.08	4%	0.35	18%	0.43	23%
6	1.86	1.94	2.29	0.08	4%	0.35	18%	0.43	23%
7	Special Rate by Customer								

BOD $ Per CCF

	2019	2019	2020	Changes					
Class	Current Rate	Rate Study	Proposed Rate	Current to Rate Study		Rate Study to Proposed		Current to Proposed	
				$	%	$	%	$	%
1	0.78	0.68	0.80	-0.10	-13%	0.12	18%	0.02	3%
2	1.28	1.11	1.31	-0.17	-13%	0.20	18%	0.03	2%
3	2.10	1.83	2.16	-0.27	-13%	0.33	18%	0.06	3%
4	3.01	2.62	3.09	-0.39	-13%	0.47	18%	0.08	3%
5	3.80	3.29	3.88	-0.51	-13%	0.59	18%	0.08	2%
6	4.67	4.05	4.78	-0.62	-13%	0.73	18%	0.11	2%
7	Special Rate by Customer								

TSS $ Per CCF

	2019	2019	2020	Changes					
Class	Current Rate	Rate Study	Proposed Rate	Current to Rate Study		Rate Study to Proposed		Current to Proposed	
				$	%	$	%	$	%
1	0.40	0.49	0.58	0.09	4%	0.35	18%	0.18	45%
2	0.82	1.00	1.18	0.18	4%	0.35	18%	0.36	44%
3	1.39	1.70	2.01	0.31	4%	0.35	18%	0.62	44%
4	1.90	2.32	2.74	0.42	4%	0.35	18%	0.84	44%
5	2.46	3.01	3.55	0.55	4%	0.35	18%	1.09	44%
6	2.98	3.65	4.31	0.67	4%	0.35	18%	1.33	45%
7	Special Rate by Customer								

Total Sewer Rate Per CCF

	2019	2019	2020	Changes					
Class	Current Rate	Rate Study	Proposed Rate	Current to Rate Study		Rate Study to Proposed		Current to Proposed	
				$	%	$	%	$	%
1	3.04	3.11	3.67	0.07	-13%	0.12	18%	0.63	21%
2	3.96	4.05	4.78	0.09	-13%	0.20	18%	0.82	21%
3	5.35	5.47	6.45	0.12	-13%	0.33	18%	1.10	21%
4	6.77	6.88	8.12	0.11	-13%	0.47	18%	1.35	20%
5	8.12	8.24	9.72	0.12	-13%	0.59	18%	1.60	20%
6	9.51	9.64	11.38	0.13	-13%	0.73	18%	1.87	20%
7	Special Rate by Customer								

Class Structure

Block	BOD Strength mg/l	TSS Strength mg/l
1	0-300	0-300
2	300-600	300-600
3	600-900	600-900
4	900-1200	900-1200
5	1200-1500	1200-1500
6	1500-1800	1500-1800
7	>1800	>1800

Proposed Sewer Rate Change Customer Impacts

Sewer Rate Change
Annual Impact on Select City Customers

Account Type	Annualized Average Winter Water Usage (CCF)	2019 Current Rate	2020 Proposed Rate	$ Changes	% Change
Residential Minimum Use	24 ccf	145.92	88.08	(57.84)	-39.64%
Residential Low Use	48 ccf	145.92	176.16	30.24	20.72%
Residential Medium Use	96 ccf	291.84	352.32	60.48	20.72%
Residential High Use	180 ccf	547.20	660.60	113.40	20.72%
Industrial 2,4	24,168 ccf	121,806.72	137,999.28	16,192.56	13.29%
Commercial 2,1	408 ccf	1,444.32	1,530.00	85.68	5.93%

*Industrial & Commercial charges are calculated based on flow rate, BOD and TSS

Sewer Rate Change
Monthly Impact on Select City Customers

Account Type	Annualized Average Winter Water Usage (CCF)	2019 Current Rate	2020 Proposed Rate	$ Changes	% Change
Residential Minimum Use	2 ccf	12.16	7.34	(4.82)	-39.64%
Residential Low Use	4 ccf	12.16	14.68	2.52	20.72%
Residential Medium Use	8 ccf	24.32	29.36	5.04	20.72%
Residential High Use	15 ccf	45.60	55.05	9.45	20.72%
Industrial 2, 4	2,014 ccf	10,150.56	11,499.94	1,349.38	13.29%
Commercial 2,1	34 ccf	120.36	127.50	7.14	5.93%

*Industrial & Commercial charges are calculated based on flow rate, BOD and TSS

Stormwater Rate Change Comparisons

Comparison of Monthly Stormwater Rate Changes

Account Type	ERUs	2019 Current Rate	2020 Proposed Rate	Changes Current to $	Changes Current to %
Single and Duplex <.25 Acre	All ERU	4.94	5.43	0.49	9.92%
Single and Duplex >.25 Acre	All ERU	6.91	7.60	0.69	9.99%
Triplex and Fourplex	All ERU	9.88	10.87	0.99	10.02%
All other Parcels	Per ERU	4.94	5.43	0.49	9.92%

*1 ERU = 1 residential property or 75 feet of street frontage for non-residential properties

Proposed Stormwater Rate Change Customer Impacts

Stormwater Rate Change
Annual Impact on Select City Customers

				Changes	
		2019	2020	Current to Proposed	
Account Type	ERUs	Current Rate	Proposed Rate	$	%
Residential less than .25 Acre	Any ERU	59.28	65.16	5.88	9.92%
Residential more than .25 Acre	Any ERU	82.92	91.20	8.28	9.99%
Industrial*	300 ERU	1,482.00	1,629.00	147.00	9.92%
Commercial	120 ERU	592.80	651.60	58.80	9.92%

Stormwater Rate Change
Monthly Impact on Select City Customers

				Changes	
		2019	2020	Current to Proposed	
Account Type	ERUs	Current Rate	Proposed Rate	$	%
Residential less than .25 Acre	Any ERU	4.94	5.43	0.49	9.92%
Residential more than .25 Acre	Any ERU	6.91	7.60	0.69	9.99%
Industrial	25 ERU	123.50	135.75	12.25	9.92%
Commercial	10 ERU	49.40	54.30	4.90	9.92%

APPENDIX E: Supplemental Information

Water Rates Compared with Recognizable Cities in Western States

Ranking	City or District Name	Average Monthly Charge
1	Flagstaff, AZ (1)	$ 121.40
2	Cheyenne, WY (2)	$ 68.60
3	Denver, CO (3)	$ 56.34
4	Reno, NV (4)	$ 51.14
5	Phoenix, AZ (5)	$ 44.67
6	Boise, ID (6)	$ 44.44
7	Las Vegas, NV (7)	$ 42.26
8	Salt Lake City, UT- 2019 Current	$ 37.44
	Salt Lake City, UT- 2020 Proposed	$ 37.17
9	Henderson, NV (8)	$ 26.47

* Cities compared with 7,480 gallons per month (10 CCF) and 24,000 gallons summer usage (32.09 CCF).
** Based on eight months Winter and four months Summer usage

Sewer Rates Compared with Nearby States

City or District Name	Average Monthly Charges
Reno, NV	$ 46.77
Boise, ID **	$ 43.33
Phoenix, AZ **	$ 37.02
Flagstaff, AZ	$ 29.92
Cheyenne, WY **	$ 29.32
Salt Lake City- 2020 Proposed	$ 29.36
Denver, CO	$ 26.99
Henderson, NV	$ 25.78
Salt Lake City- 2019 Current	$ 24.32
Las Vegas, NV	$ 19.76

*   Monthly Average Charges calculated based on 5,984 gallons per month (or 8 CCF)
** Includes Monthly base rate

Sewer Rates Compared with Local Cities November 2018

Ranking	City or District Name	Annual Charge
1	City of South Salt Lake	$ 502.66
2	Kearns Improvement District	$ 425.34
3	Magna City	$ 381.63
4	Ogden City	$ 364.56
	Salt Lake City- 2020 Proposed	$ 352.32
5	South Valley Sewer District	$ 332.56
6	Murray City **	$ 323.63
7	West Jordan City **	$ 323.09
8	Granger - Hunter Improvement District	$ 322.55
9	Midvalley Improvement District	$ 295.29
10	Salt Lake City- 2019 Current	$ 291.84
11	Taylorsville - Bennion Improvement District**	$ 265.95
12	Cottonwood Improvement District	$ 259.36
13	Sandy Suburban Improvement District	$ 257.04
14	Mt Olympus Improvement District	$ 234.69
15	South Davis Sewer District	$ 146.95

* Annual cost based on 12 months at 5,984 gallons per month (or 8 CCF per month) average winter consumption. Flat rate based on monthly rate multiplied by 12.

** Includes monthly base rate

Stormwater Rates Compared with Local Cities November 2018

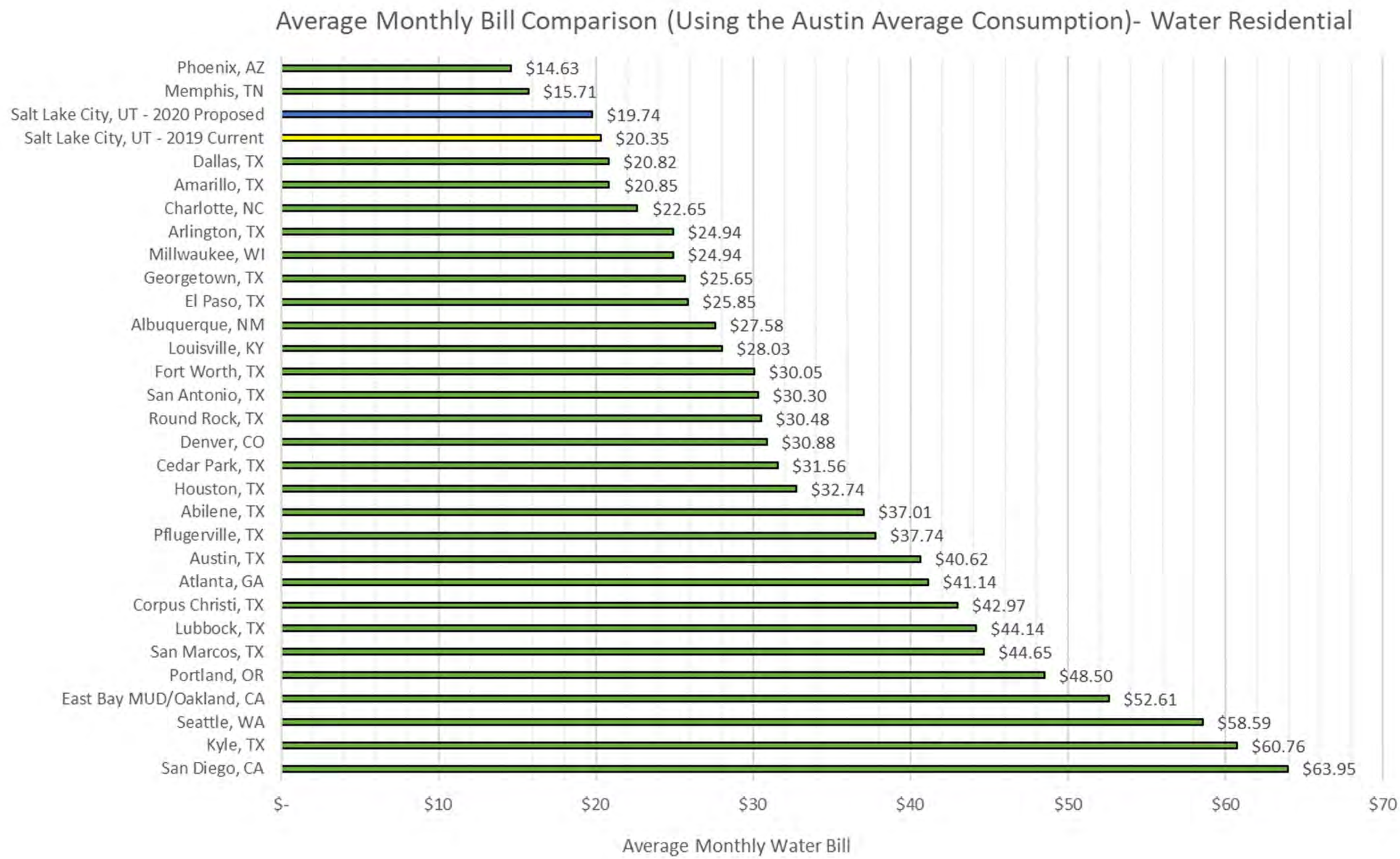
RANKING	CITY NAME	CURRENT RATE
1	PLEASANT GROVE	12.48
2	PROVO	9.20
3	DRAPER CITY	9.00
4	OGDEN CITY	7.85
5	SOUTH JORDAN CITY	7.15
6	BOUNTIFUL CITY	7.00
7	OREM	6.75
8	AMERICAN FORK	6.00
8	SANDY CITY	6.00
	SALT LAKE CITY (PROPOSED)	5.43
9	SALT LAKE CITY (Current)	4.94
10	MURRAY CITY	4.65
11	WEST JORDAN CITY	4.50
12	TAYLORSVILLE CITY	4.00

Public Utilities Department Local Area Water Rate Comparison
November 2018 (Highest to Lowest Ranking)

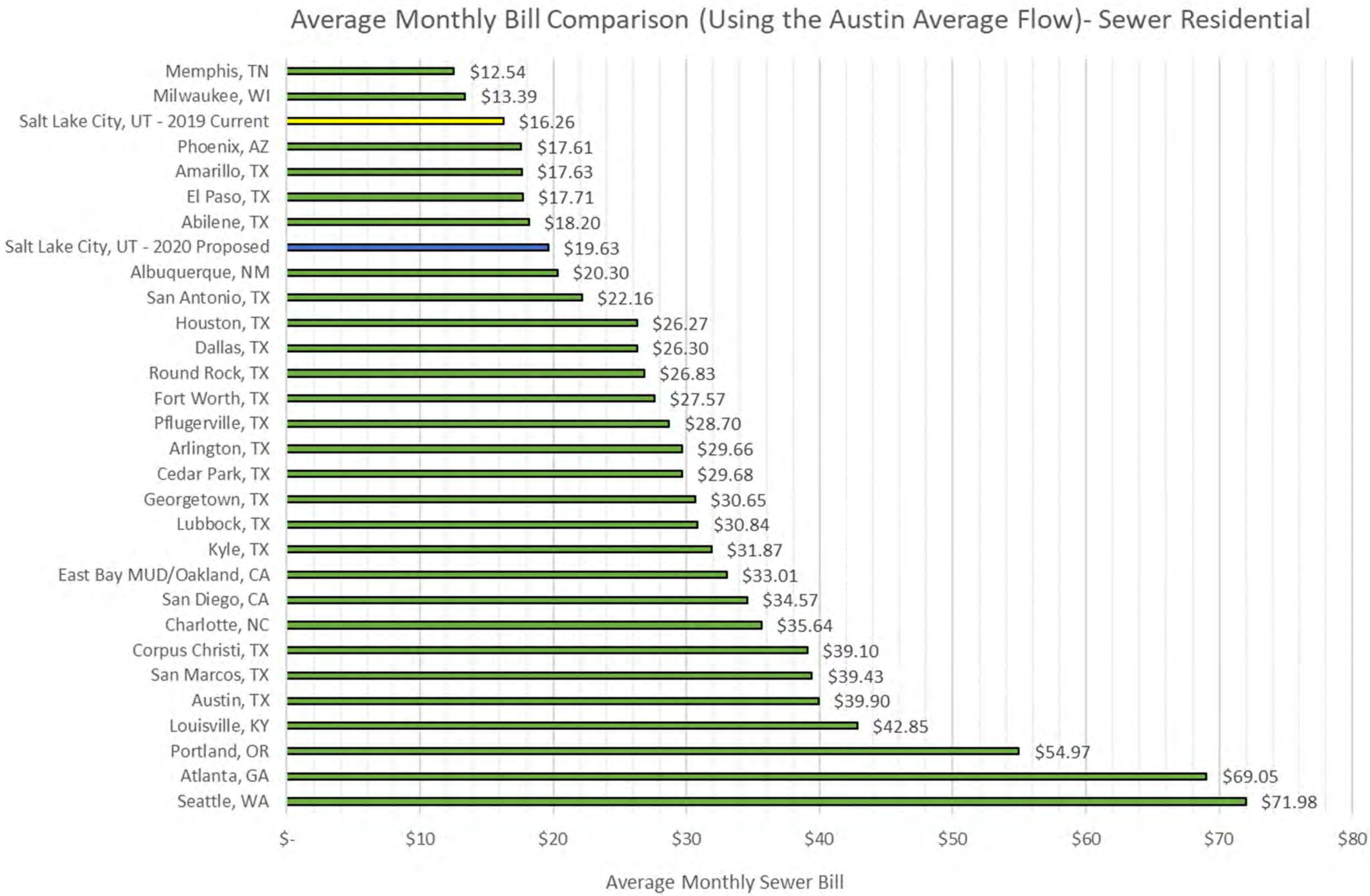
RANKING	CITY OR DISTRICT NAME	MONTHLY MINIMUM CHARGE	MINIMUM ALLOWANCE IN GALLONS	RATE OVER MINIMUM ALLOWANCE	PER GALLONS	MONTHLY FLOURIDE CHARGE	WINTER @ 7,480 GAL PER MONTH	SUMMER @ 23,936 GAL PER MONTH	TOTAL WINTER CHARGES*	TOTAL SUMMER CHARGES*	YEARLY TAX ON $200,000 PROPERTY	TOTAL CHARGES
1	PARK CITY - GRADUATED RATES (1)	49.08	0	6.12 - 10.31	1,000		104.01	269.91	832.07	1079.64		1911.71
2	AMERICAN FORK - GRADUATED RATES (2)	22.67	3,000	3.52 - 4.96	1,000		39.51	120.03	316.04	480.13		796.17
3	DRAPER CITY - GRADUATED RATES (3)	20.25	0	2.05 - 3.71	1,000		39.08	97.00	312.65	388.01		700.66
4	SOUTH JORDAN CITY - GRADUATED RATES (4)	30.00	0	2.00 - 2.50	1,000		45.33	84.09	362.64	336.36		699.00
5	RIVERTON CITY - GRADUATED RATES (5)	2.50	0	3.76 - 3.91	1,000		31.00	95.34	247.97	381.36		629.33
6	PLEASANT GROVE - GRADUATED RATES (6)	20.81	5,000	2.52 - 5.27	1,000		27.06	98.90	216.48	395.61		612.09
7	OGDEN CITY - GRADUATED RATES (7)	20.90	0	1.79 - 2.74	1,000		35.70	80.78	285.56	323.14		608.70
8	SALT LAKE CITY - OUTSIDE OF CITY	13.35	0	1.82 - 3.47	748		31.55	88.49	252.40	353.96		606.36
	SALT LAKE CITY - OUTSIDE OF CITY (Proposed)	12.53	0	1.84 -3.50	748		30.93	88.33	247.44	353.32		600.76
9	SANDY CITY - OUTSIDE OF CITY (8)	19.95	0	1.80 - 2.75	1,000		34.82	80.07	278.56	320.30		598.86
10	WEST JORDAN CITY (11)	26.58	0	1.65 - 2.18	1,000		39.04	71.41	312.34	285.64		597.98
11	KEARNS IMPROVEMENT DIST-GRADUATED RATES (9)	11.60	0	2.33 - 2.92	1,000		29.03	75.59	232.23	302.37	51.04	585.64
12	MAGNA - GRADUATED RATES (10)	17.41	6,000	1.89 - 2.12	1,000	0.98	21.19	53.65	169.50	214.62	178.81	562.92
13	SANDY CITY - INSIDE OF CITY (12)	14.43	0	1.64 - 2.53	1,000		28.01	69.65	224.12	278.59	35.75	538.46
14	SALT LAKE CITY - INSIDE OF CITY (13)	9.89	0	1.35 - 2.57	748		23.39	65.53	187.12	262.12	33.22	482.46
	SALT LAKE CITY - INSIDE OF CITY (Proposed)	9.28	0	1.37 - 2.59	748		22.98	65.56	183.84	262.24	35.75	481.83
15	BOUNTIFUL CITY - RESIDENTIAL HIGH ELEVATION	23.57	5,000	1.98	1,000		28.48	61.06	227.84	244.25		472.10
16	CITY OF SOUTH SALT LAKE	19.00	5,000	2.25	1,000	2.00	26.58	63.61	212.64	254.42		467.06
17	GRANGER - HUNTER IMPROVEMENT DISTRICT (14)	13.00	0	1.61 -1.86	1,000		25.10	54.73	200.80	218.92	28.55	448.27
18	BOUNTIFUL CITY - RESIDENTIAL LOW ELEVATION	21.39	5,000	1.79	1,000		25.83	55.29	206.63	221.14		427.78
19	JVWCD	3.00	0	1.87 - 2.34	1,000		16.99	59.01	135.90	236.04	44.00	415.94
20	PROVO	15.29	0	0.87 - 1.44	1,000		21.80	49.76	174.38	199.03		373.41
21	TAYLORSVILLE/BENNION IMPROVEMENT DISTRICT (15	7.00	0	1.43 - 1.87	1,000		18.35	49.12	146.78	196.48	6.88	350.14
22	MURRAY CITY - GRADUATED RATES (16)	10.00	0	0.95 - 1.40	748		19.90	46.95	159.20	187.80		347.00
23	OREM - GRADUATED RATES (17)	17.16	0	0.79 - 0.99	1,000		23.07	38.66	184.55	154.63		339.18

CALCULATION OF COMPARISONS

** BASED ON EIGHT MONTHS WINTER AND FOUR MONTHS SUMMER*
(1) RATES ARE $6.12/THOUSAND FOR 0-5,000 GALLONS, $9.81/THOUSAND FOR 5,001-15,000 GALLONS, & $10.31/THOUSAND FOR 15,001-25,000 GALLONS
(2) RATES ARE $22.67 FOR 0-3,000 GALLONS, $3.52/THOUSAND FOR 3,001-6,000 GALLONS, $4.24/THOUSAND FOR 6,000-9,000 GAL & $4.96/THOUSAND OVER 9,000 GALLONS
(3) RATES ARE $2.05/THOUSAND FOR 0-5,000 GALLONS, $3.46/THOUSAND FOR 5,001-20,000 GALLONS, & $3.71/THOUSAND FOR 20,001-50,000 GALLONS
(4) RATES ARE $2.00/THOUSAND FOR 0-6,000 GALLONS, $2.25/THOUSAND FOR 6,001-17,000 GALLLONS & $2.50/THOUSAND FOR 17,001 - 42,000 GALLONS
(5) RATES ARE $3.76 FOR 0-5,000 GALLONS & $3.91/THOUSAND OVER 5,000 GALLONS
(6) RATES ARE $20.81 FOR 0-5,000 GALLONS, $2.52/THOUSAND FOR 5,001-10,000 GALLONS, $3.68/THOUSAND FOR 10,001-15,000 GALLONS & $5.27/THOUSAND OVER 15,000 GALLONS
(7) RATES ARE $1.79/THOUSAND FOR 0-6,000 GALLONS & $2.74/THOUSAND FOR 6,001-42,000 GALLONS
(8) RATES ARE $1.80/THOUSAND FOR 0-6,000 GALLONS & $2.75/THOUSAND FOR 6,001-40,000 GALLONS
(9) RATES ARE $2.33/THOUSAND FOR 0-10,000 GALLONS & $2.92/THOUSAND FOR 10,001-25,000 GALLONS
(10) RATES ARE $1.64/THOUSAND FOR 0-6,000 GALLONS & $2.53/THOUSAND FOR 6,001-40,000 GALLONS
(11) RATES ARE $17.41 FOR 0-6,000 GALLONS, $1.89/THOUSAND FOR 6,001-18,000 GALLONS, & $2.12/THOUSAND FOR 18,001-35,000 GALLONS
(12) RATES ARE $1.65 FOR 0-7,000 GALLONS, $1.90/THOUSAND FOR 7,001-20,000 GALLONS, & $2.18/THOUSAND FOR OVER 20,000 GALLONS
(13) INCLUDES METROPOLITAN WATER PROPERTY TAX
(14) RATES ARE $1.61/THOUSAND FOR 0-7,000 GALLONS, $1.73/THOUSAND FOR 7,001-15,000 GALLONS & $1.86/THOUSAND FOR OVER 15,000 GALLONS
(15) RATES ARE $1.43/THOUSAND FOR 0-6,000 GALLONS & $1.87/THOUSAND FOR 6,001-25,000 GALLONS
(16) RATES ARE $.95/HUNDRED FOR 0-8 HCF, $1.15/HUNDRED FOR 9-25 HCF & $1.40/HUNDRED FOR 26-49 HCF
(17) RATES ARE $.79/THOUSAND FOR 0-11,000 GALLONS, $.99/THOUSAND FOR 11,001-34,000 GALLONS

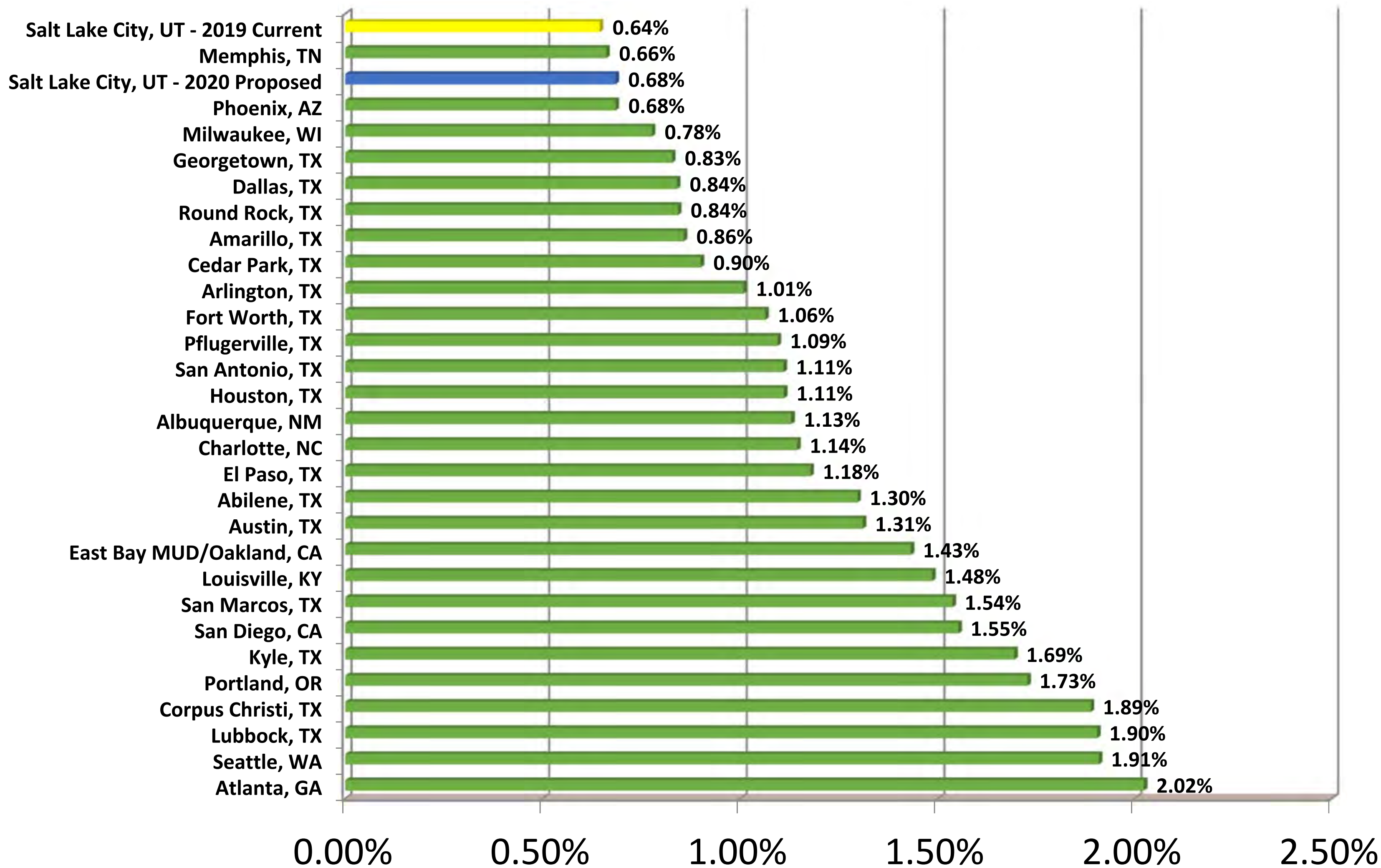


*Cities Other than SLC- Data Source Rates from March 2018 Austin National Survey
** Rates Calculated of an average of 5,800 gallons a month or 7.54 CCF

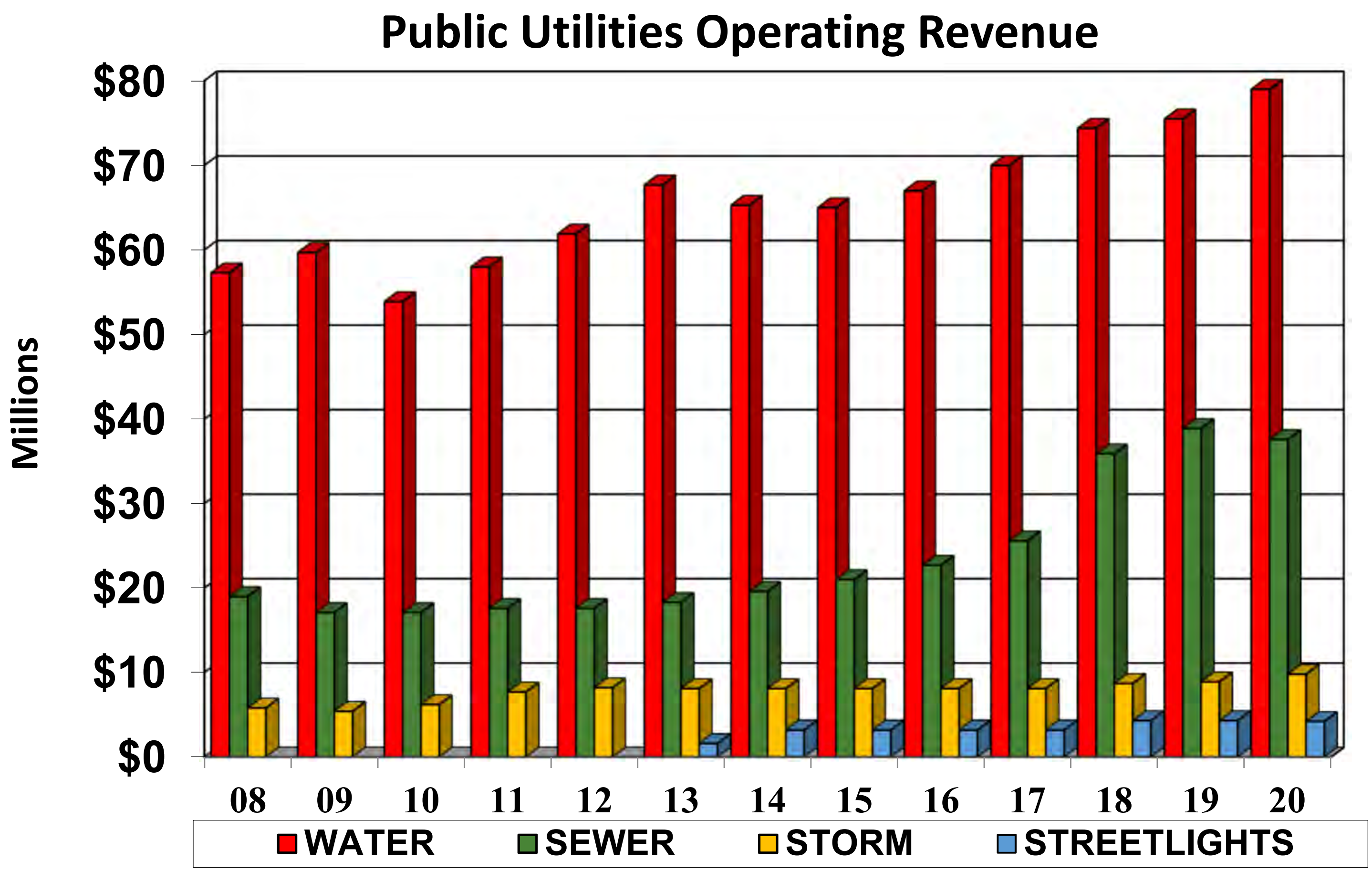


*Cities Other than SLC- Data Source Rates from March 2018 Austin National Survey
** Rates Calculated of an average of 4,000 gallons a month or 5.35 CCF

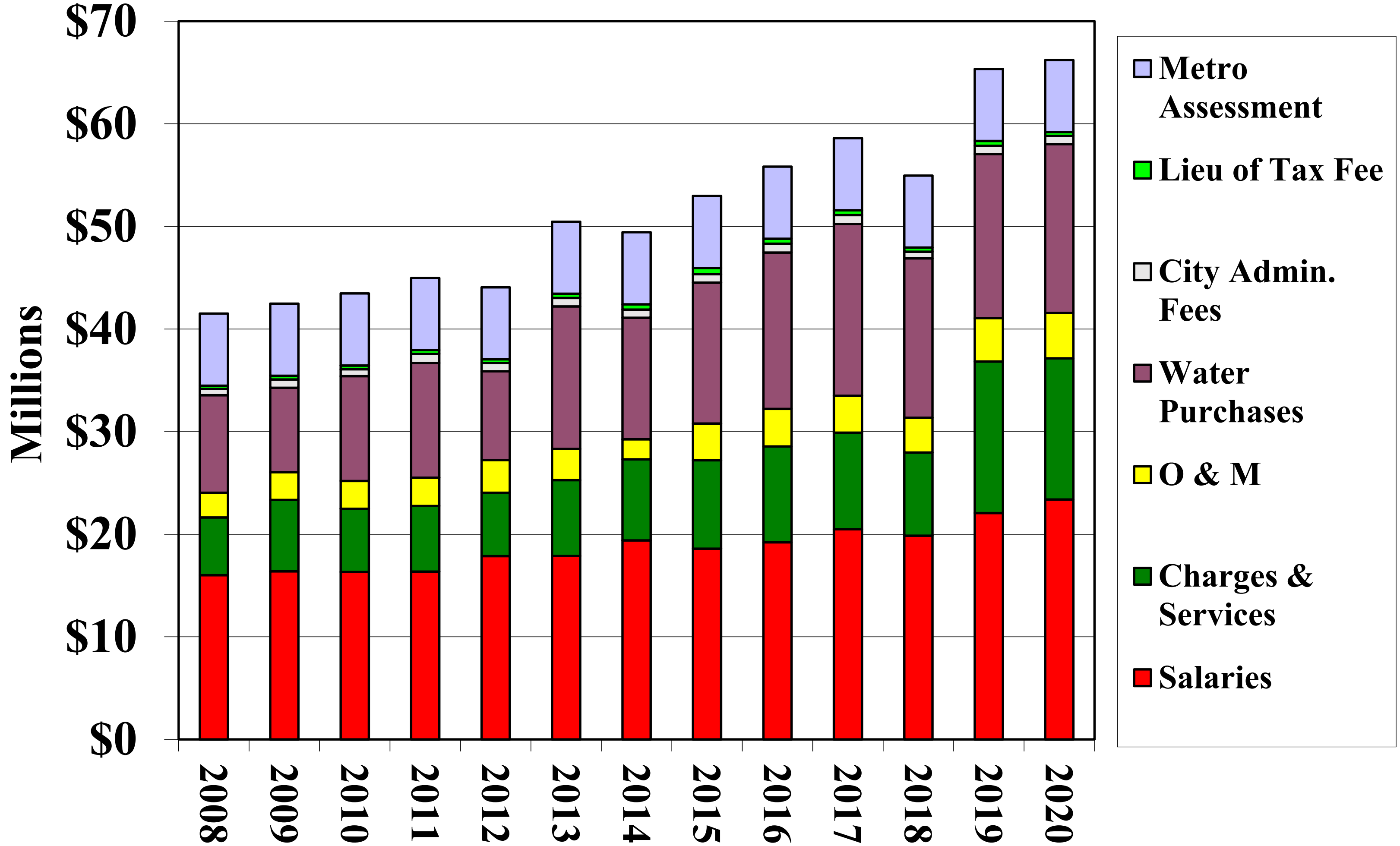
Residential Water & Sewer Bill as a Percent of Median Household Income
(Using Austin Average Consumption & Flows as of March 2018 Report)

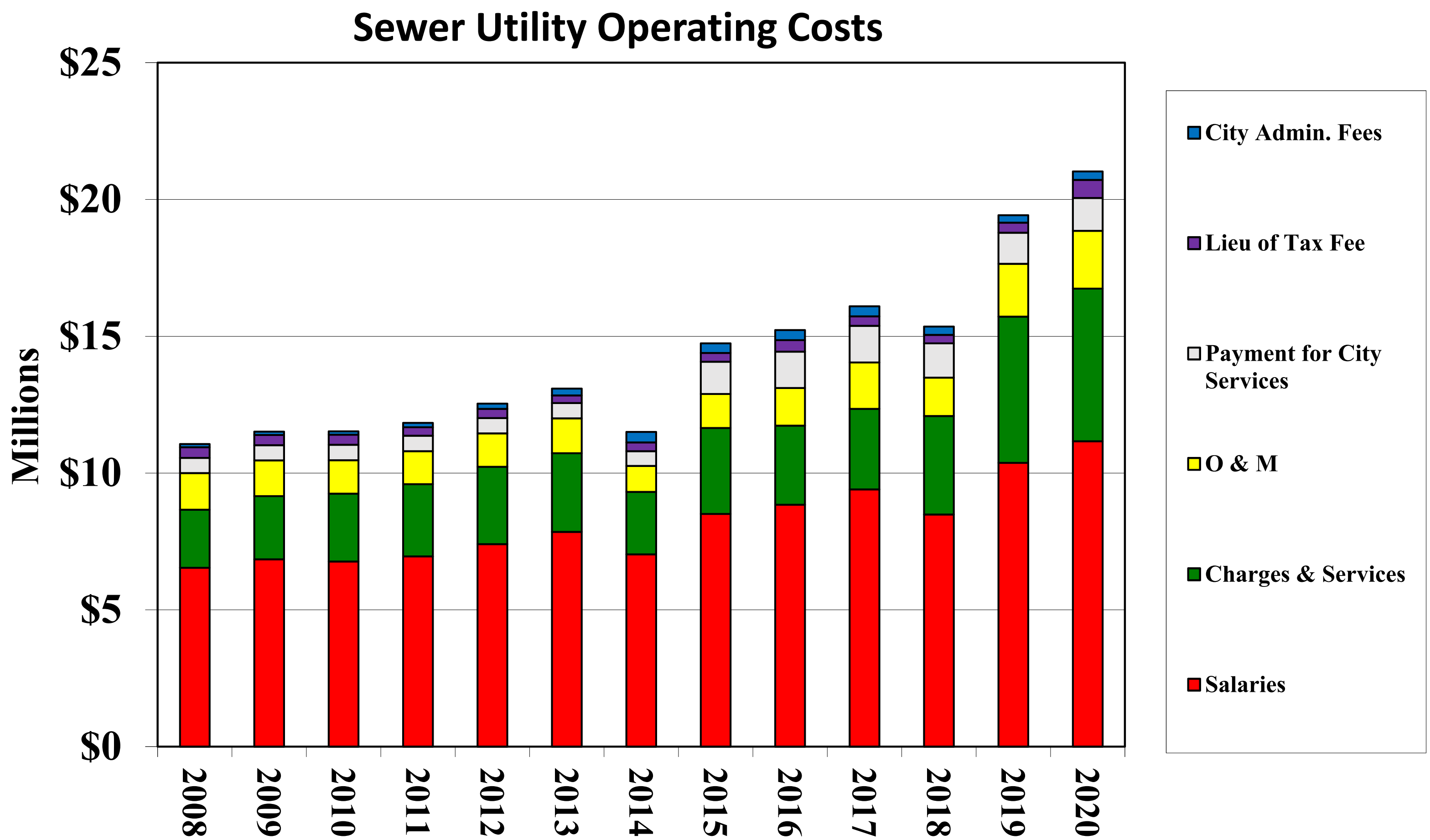


* The percentage of median household income was calculated by taking the results of each individual city's bill based on that city's rates and the usage of the Austin average consumption and flows. From those results, we divide the annual amount by the individual city's 10 year average median income.
** Median Income source: www.deptofnumbers.com/income/us/l

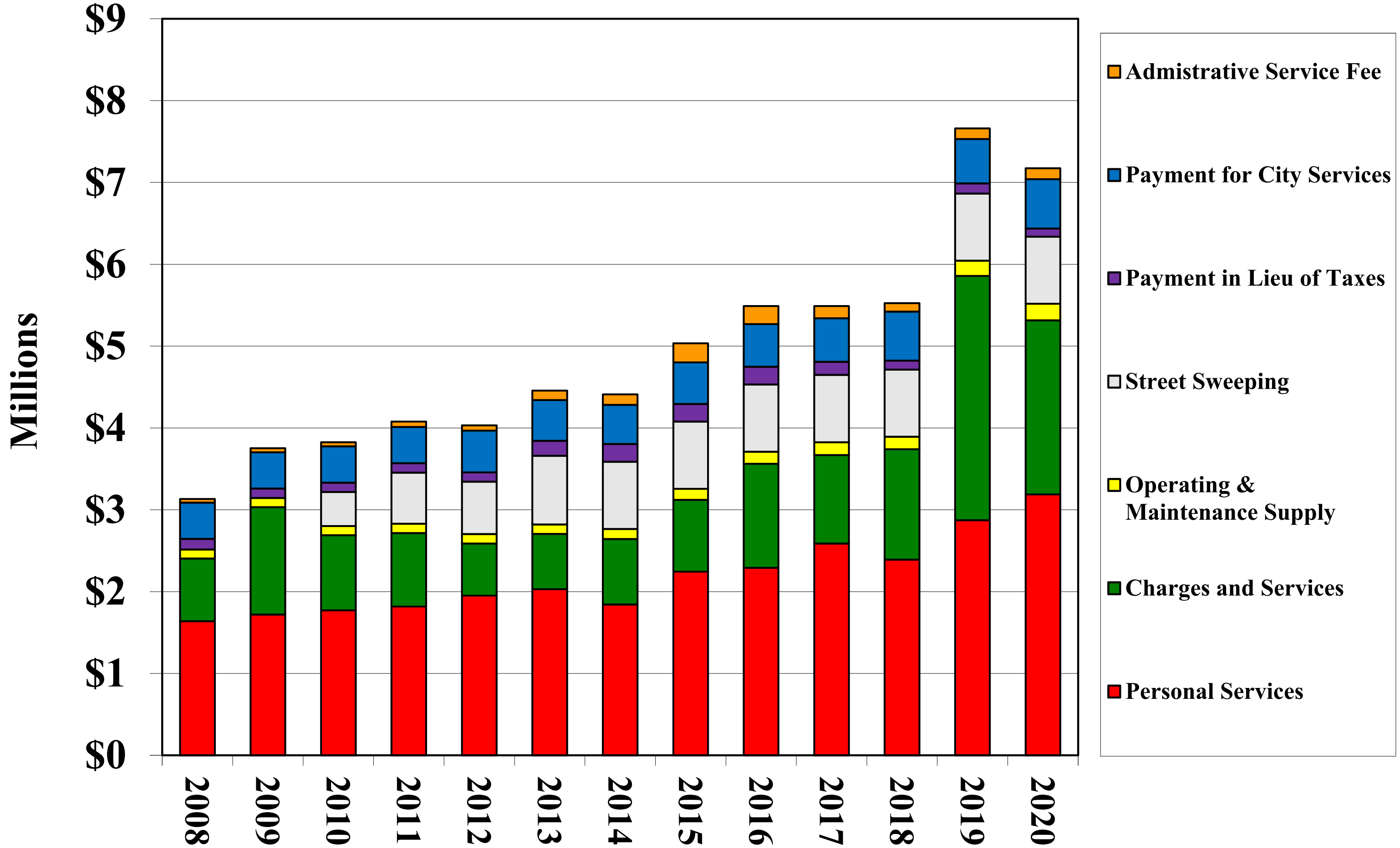

Public Utilities Operating Revenue
$80
$70
$60
$50
$40
$30
$20
$10
$0
Millions
08
09
10
11
12
13
14
15
16
17
18
19
20
WATER
SEWER
STORM
STREETLIGHTS

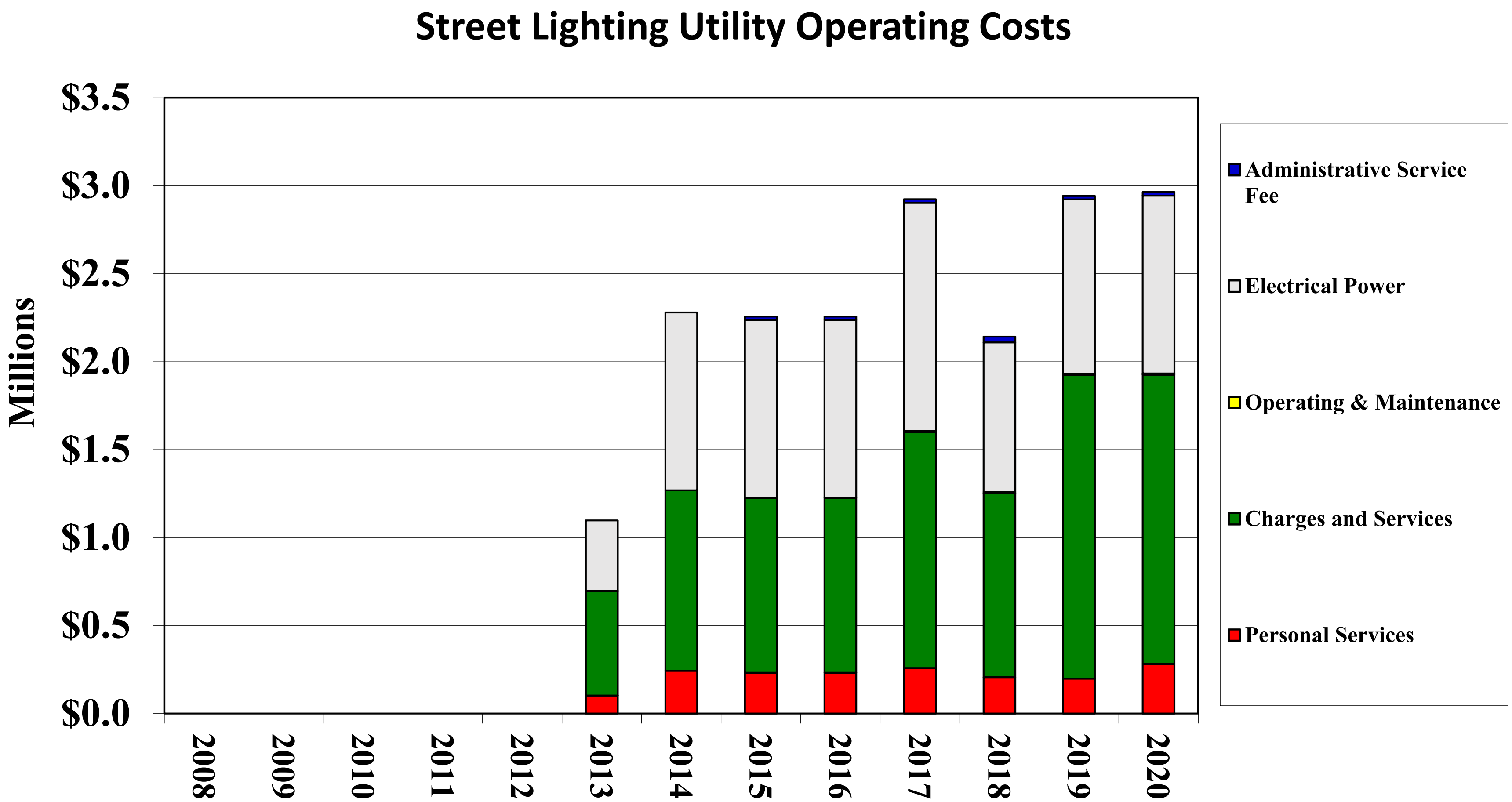
Water Utility Operating Costs

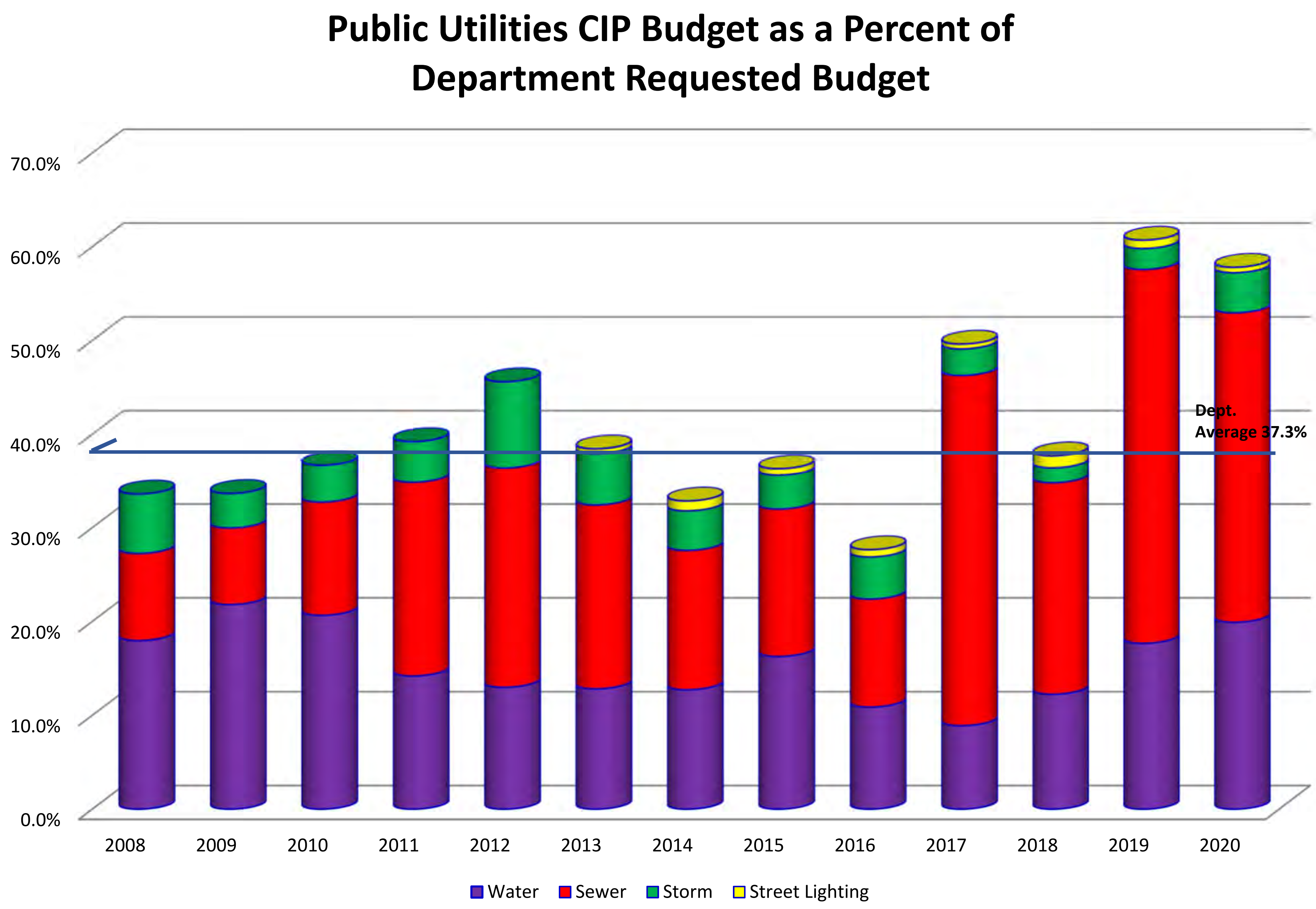



Sewer Utility Operating Costs
$25
$20
$15
$10
$5
$0
Millions
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
City Admin. Fees
Lieu of Tax Fee
Payment for City Services
O & M
Charges & Services
Salaries

Stormwater Utility Operating Costs

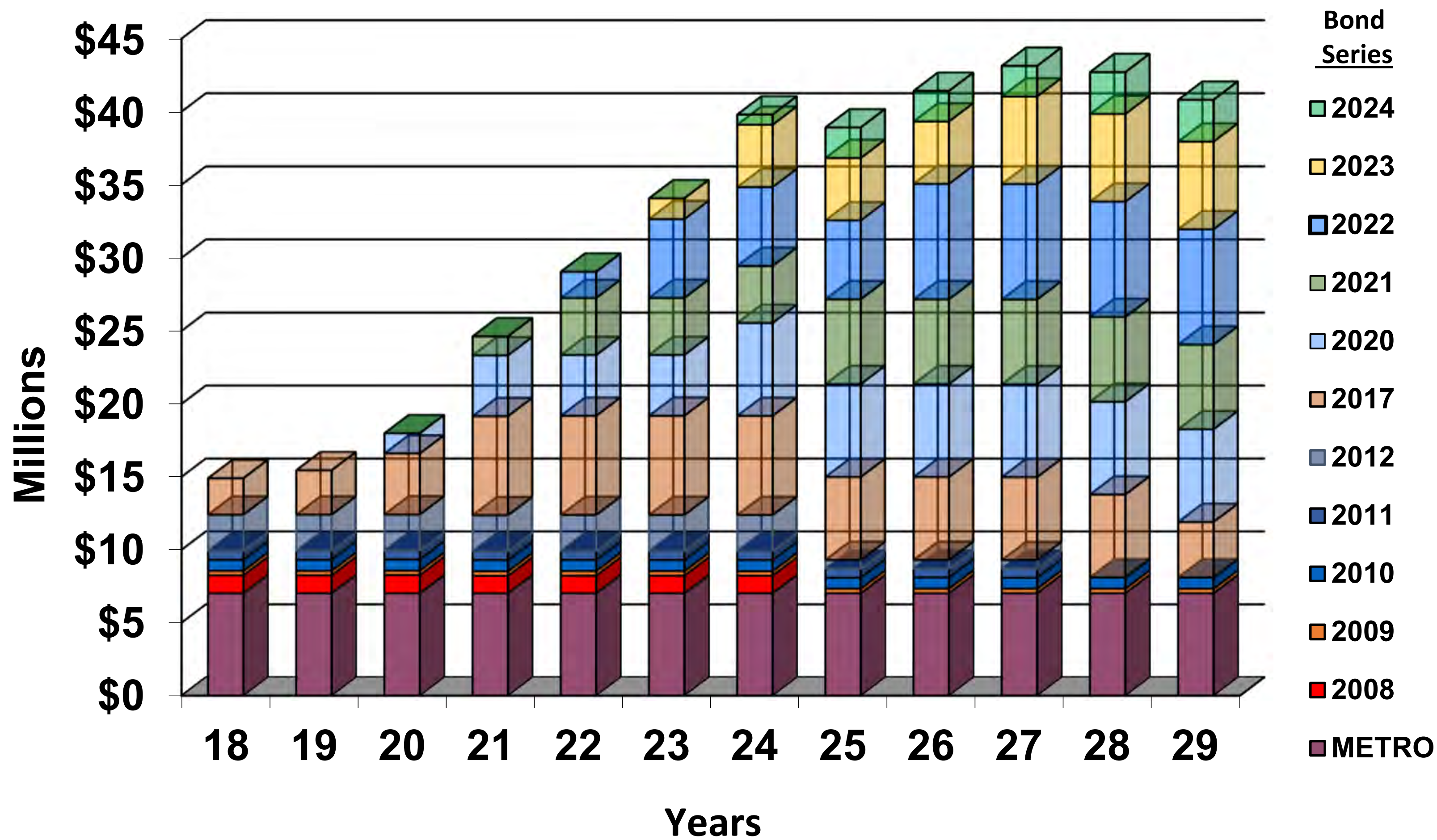


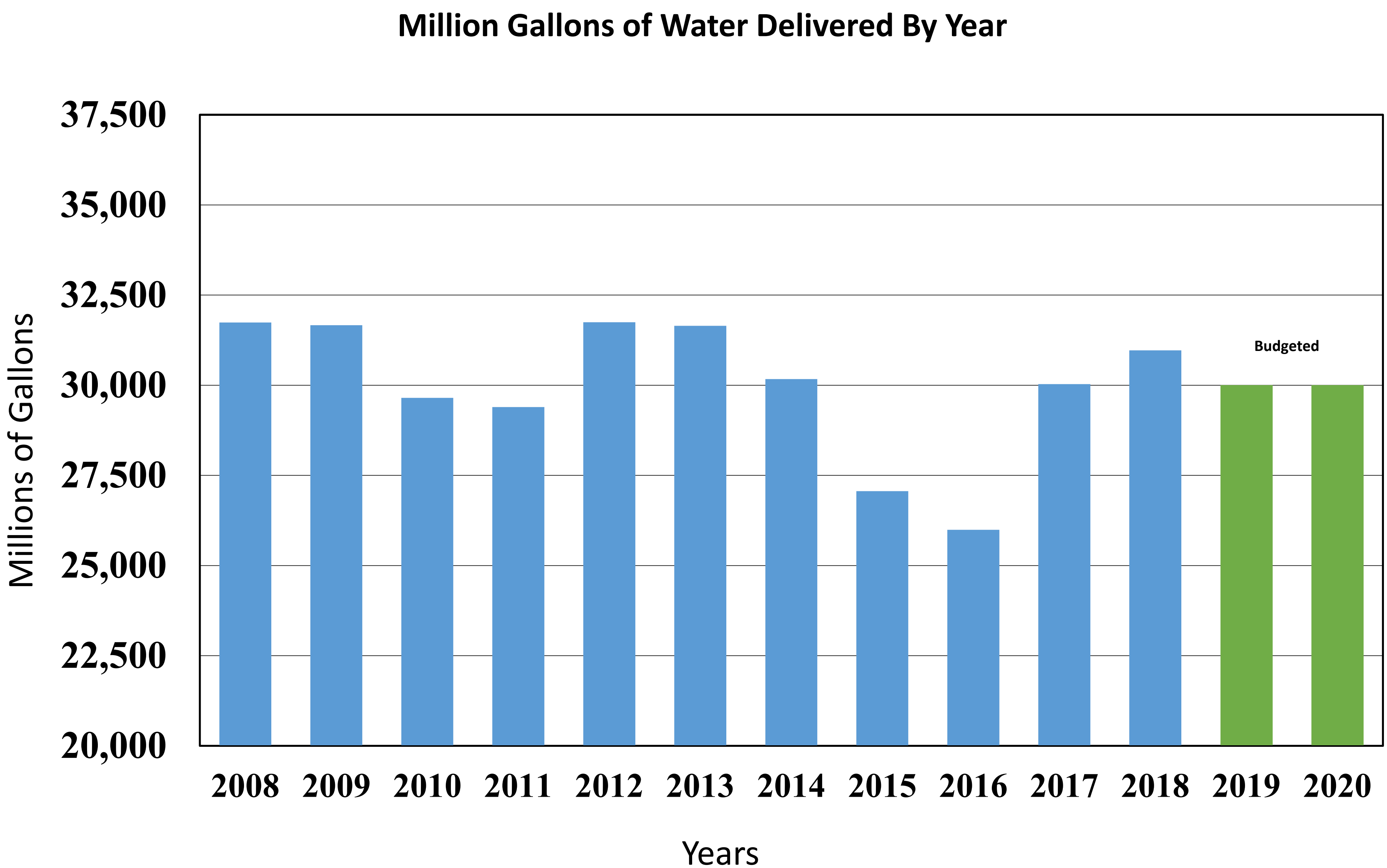

Street Lighting Utility Operating Costs
$3.5
$3.0
$2.5
$2.0
$1.5
$1.0
$0.5
$0.0
Millions
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
Administrative Service Fee
Electrical Power
Operating & Maintenance
Charges and Services
Personal Services

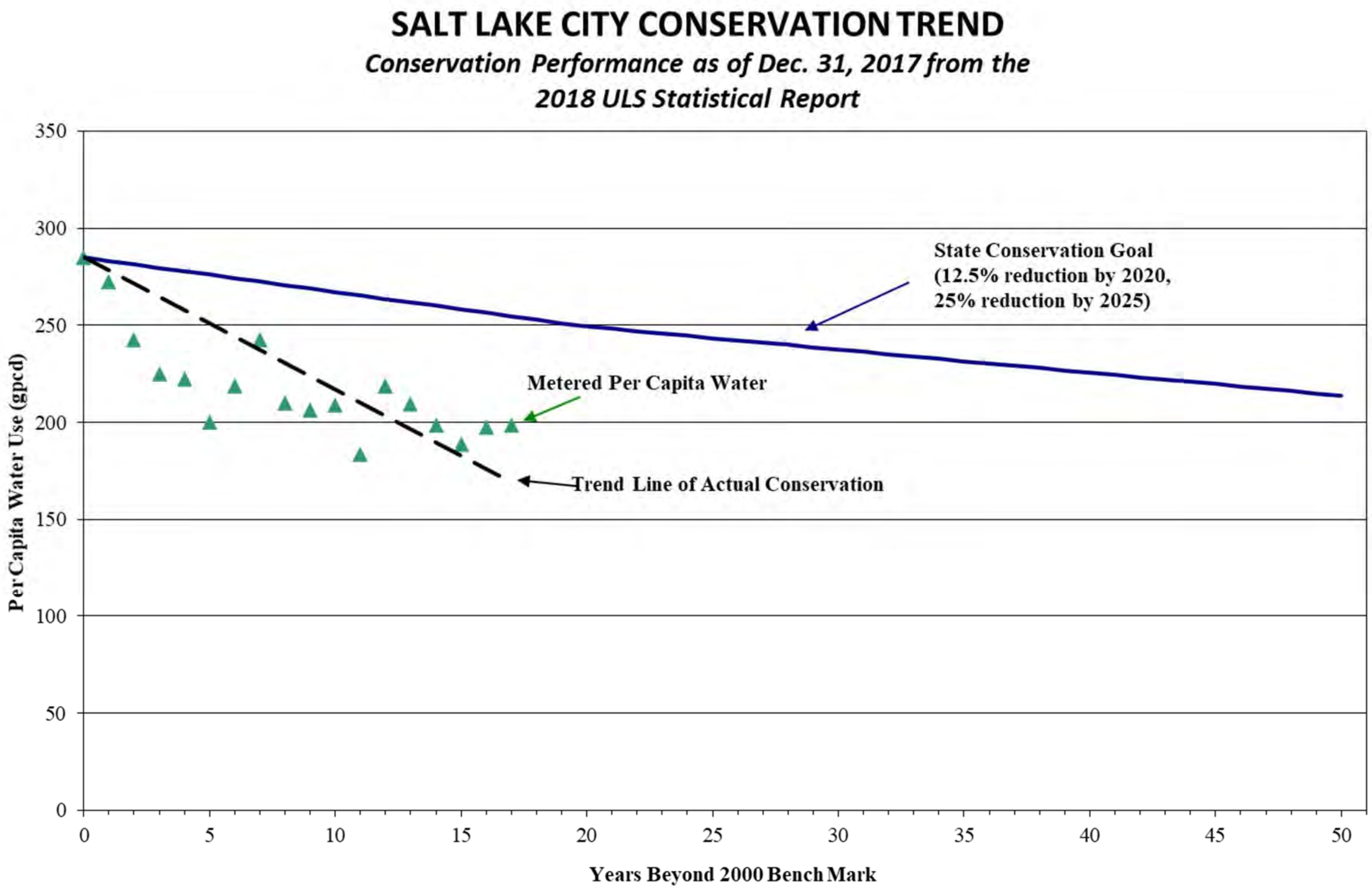


Public Utilities CIP Budget as a Percent of Department Requested Budget
70.0%
60.0%
50.0%
40.0%
30.0%
20.0%
10.0%
0.0%
Dept. Average 37.3%
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
Water
Sewer
Storm
Street Lighting

Public Utilities Proposed Debt Service Schedule and Metropolitan Water Assessment



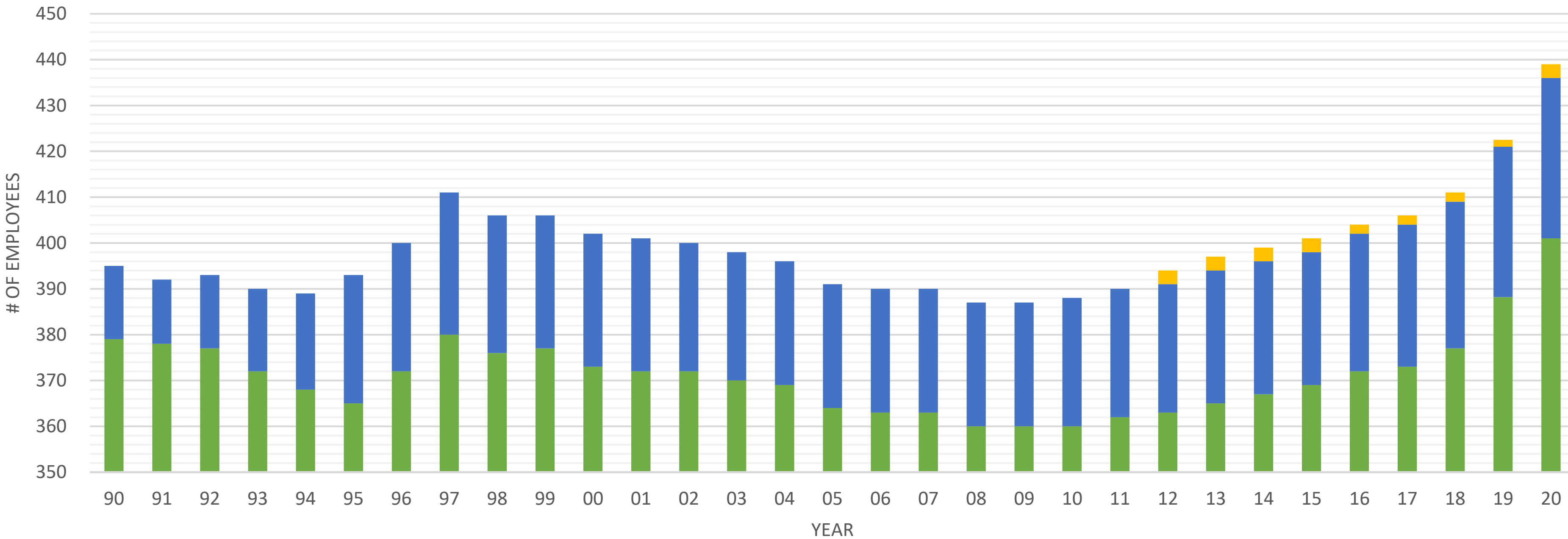

Million Gallons of Water Delivered By Year
37,500
35,000
32,500
30,000
27,500
25,000
22,500
20,000
Millions of Gallons
Budgeted
2008
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
Years


SALT LAKE CITY CONSERVATION TREND
Conservation Performance as of Dec. 31, 2017 from the
2018 ULS Statistical Report
State Conservation Goal
(12.5% reduction by 2020,
25% reduction by 2025)
Metered Per Capita Water
Trend Line of Actual Conservation
Per Capita Water Use (gpcd)
Years Beyond 2000 Bench Mark
0
50
100
150
200
250
300
350
5
10
15
20
25
30
35
40
45
50

Proposed Personnel Adjustments FY 2019/2020

	TOTAL	WATER	SEWER	STORM WATER	STREET LIGHTING
Prior FY Ending FTE Balances by Fund	422.50	272.77	115.43	32.80	1.50
NEW POSITIONS REQUESTED FOR FY 19/20					
1) RECORDS TECHNICIAN	1.00	0.80	0.10	0.10	
2) COMMUNITY & ENGAGEMENT COORD	1.00	0.50	0.40	0.10	
3) SUSTAINABILITY PROGRAM MANAGER	1.00	1.00			
4) GIS LEAK DETECTOR SYSTEM TECH II UNON	1.00	0.50	0.30	0.20	
5) OFFICE TECHNICIAN II	1.00		1.00		
6) PRETREATMENT INSPECTOR/PERMIT WRITER	1.00		1.00		
7) PRETREATMENT SENIOR SAMPLER/INSPECTOR	1.00		1.00		
8) FOG/SEWER RATE PROGRAM SUPERVISOR	1.00		1.00		
9) MAINTENANCE ELECTRICIAN IV	1.00	1.00			
10) ENGINEERING TECH I	1.00				1.00
11) ENGINEERING TECH II	2.00	1.00	0.50	0.50	
12) ENGINEERING TECH III	1.00	0.50	0.25	0.25	
13) ENGINEER II	1.00	0.50	0.25	0.25	
14) ENGINEER III	2.00	1.00	0.50	0.50	
Total Increase of 16 FTE's for Public Utilities Dept.	438.50	279.57	121.73	34.70	2.50
Two Seasonal Watershed Workers	1.00	1.00			
TOTAL FTE'S	439.50	280.57	121.73	34.70	2.50
CHANGES TO FTE DUE TO REORGANIZATION:		1.65	-1.10	-0.55	0.00
Agency Totals for FY 2019/2020	439.50	282.22	120.63	34.15	2.50

Public Utilities Number of Employees By Fund By Fiscal Year



Year	90	91	92	93	94	95	96	97	98	99	00	01	02	03	04	05	06	07	08	09	10	11	12	13	14	15	16	17	18	19	20
Water & Sewer	379	378	377	372	368	365	372	380	376	377	373	372	372	370	369	364	363	363	360	360	360	362	363	365	367	369	372	373	377	388	401
Storm Water	16	14	16	18	21	28	28	31	30	29	29	29	28	28	27	27	27	27	27	27	28	28	28	29	29	29	30	31	32	33	35
Street Lighting																							3	3	3	3	2	2	2	2	3
# of Water Connections	84,098	84,526	85,921	86,360	86,665	87,233	85,514	89,191	90,393	89,776	80,218	90,766	91,283	81,751	92,955	92,344	90,748	90,912	90,920	90,976	90,958	90,624	90,251	90,349	90,435	90,451	91,467	91,545	91,802	???	???

Public Utilities

Sewer Collections

Program Objectives:

- Existing capacity & condition issues
- Growth related infrastructure
- Odor control
- Support of Roadway Bonding

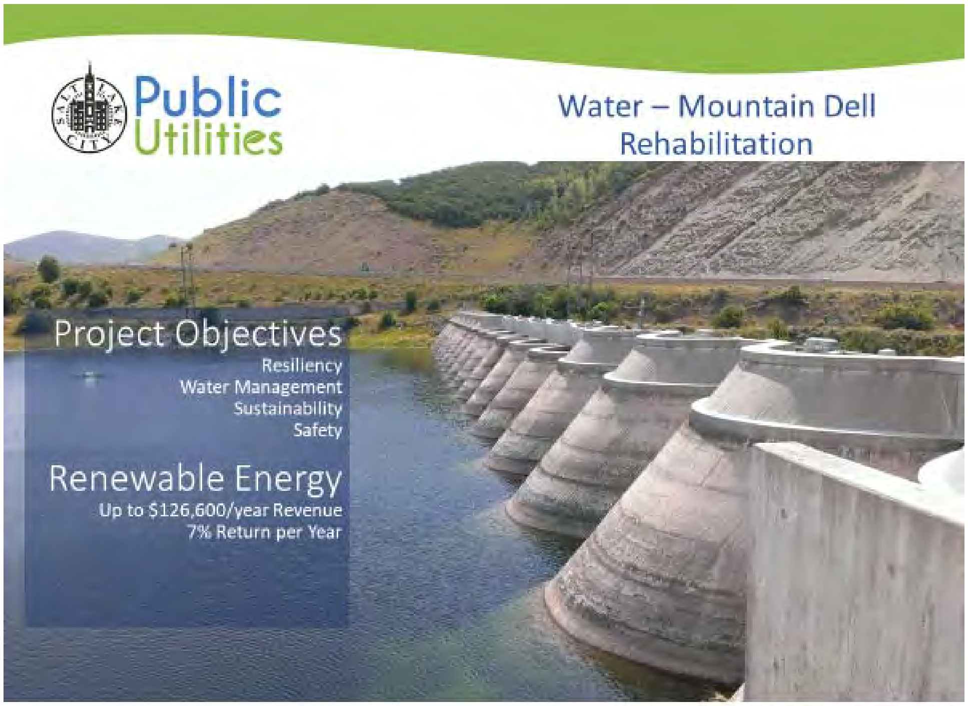
Program Magnitude:

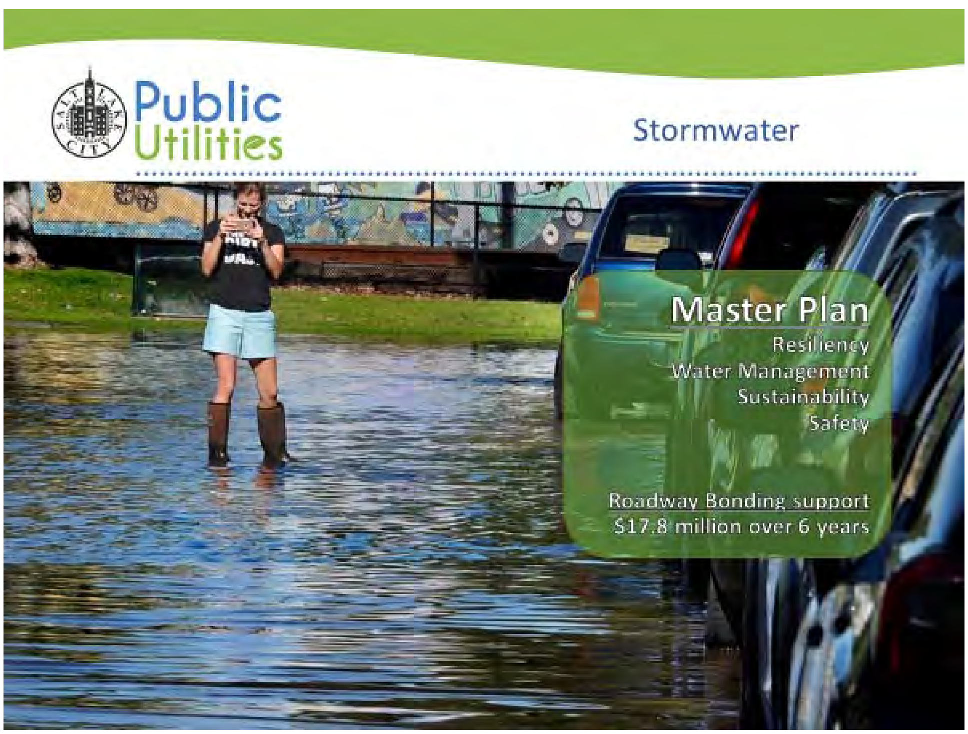
- +/- $191M in capital infrastructure through 2025

Public Utilities

Water – Capital Program

- **East West Aqueduct Phase I ($10.0 million)**
- **Treatment Plant rehabilitation ($8.0 million)**
- **Road way bond support $9.65 million FY 20 (~$27.54 million over 6 years)**
- **Total Water Main Replacements ($23 million)**


Public Utilities
Water – Mountain Dell Rehabilitation
Project Objectives
Resiliency
Water Management
Sustainability
Safety
Renewable Energy
Up to $126,600/year Revenue
7% Return per Year


Public Utilities
Stormwater
Master Plan
Resiliency
Water Management
Sustainability
Safety
Roadway Bonding support
$17.8 million over 6 years

JACQUELINE M. BISKUPSKI
Mayor

DEPARTMENT OF
PUBLIC UTILITIES

CITY COUNCIL TRANSMITTAL

Patrick Leary, Chief of Staff

Date Received: 4/5/2019
Date sent to Council: 4/9/2019

TO: Salt Lake City Council
Charlie Luke, Chair

DATE: April 5, 2019

FROM: Laura Briefer, MPA
Director, Department of Public Utilities

SUBJECT: Request for City Council adoption of new water and sewer rate structures pursuant to the recommendations of the 2018 Comprehensive Water, Sewer, and Stormwater Rate Study, and in coordination with approval of Public Utilities' approved Fiscal Year 2019-2020 Budget

STAFF CONTACTS: Lisa Tarufelli, Finance Administrator, lisa.tarufelli@slcgov.com

Laura Briefer and Lisa Tarufelli will address the Council on this resolution.

DOCUMENT TYPE: Ordinance (**Exhibit A**)

RECOMMENDATION: Approve an ordinance that would adopt the recommended new water and sewer rate structures, in coordination with approval of Public Utilities' proposed Fiscal Year 2019-2020 Budget.

BUDGET IMPACT:
The rate structure design is revenue neutral and does not impact Public Utilities' budget.

BACKGROUND/DISCUSSION:
Public Utilities completed a Comprehensive Water, Sewer, and Stormwater Rate Study (Rate Study) in 2018. The executive summary of the Rate Study is included in **Exhibit B**. Public Utilities' objectives are to retain defensible rate structures and fees, while meeting other important rate objectives, such as sufficient revenue, rate stability, conservation, and equity. For this Rate Study, Public Utilities contracted with Raftelis, a recognized expert in water rate setting, and used industry-standard utility cost of service methodology as reflected in the American Water Works Association *Manual of Water Supply Practices M1, Principles of Water Rates, Fees, and Charges* and in the *Water Environment Federation Manual of Practice No. 27, Financing and Charges for Wastewater Systems.*

Water Rates

Three substantive changes are recommended to the existing water rate structure to address key objectives of conservation, affordability, rate stability, demand management, and interclass equity. These include the following structural changes:

- Change the system-wide cost of service rate structure (where volume rates by block are the same for all customers) to a customer class cost of service volume rate structure. This results in different volume rates for residential, commercial, and industrial classes that reflect the specific cost to provide service to each class. The Rate Advisory Committee (RAC) established for the Rate Study, and the Public Utilities Advisory Committee (PUAC) felt this rate structure meets goals related to equity. It also reduces the allocation of costs to residential classes, which helps to address essential use affordability for the residential class.
- Reduce the block four threshold from 70 ccf (hundred cubic feet) to 60 ccf for residential, duplex and triplex customer classes. Reduce the commercial, institutional, and industrial customer class block four threshold from 700% of annual winter consumption (AWC) to 600% of AWC. This addresses both conservation and demand management priorities through stronger water pricing signals.
- Retain the fixed charge by meter size, but modify the price ratio between the meter sizes to reflect the capacity potential of each meter size relative to a ¾" meter. This addresses goals related to equity and helps promote residential essential use affordability.

A cost of service analysis was also completed to establish a new secondary water irrigation rate. This is due to the development of secondary water systems operated at certain Salt Lake City golf courses. Public Utilities does not operate a secondary water irrigation system, so secondary water irrigation rates had not been previously established. To help address conservation and demand management goals, the design of the secondary irrigation water rate structure includes the same inclining block volume rate structure as the culinary water irrigation meter rate.

Sewer Rates

The RAC and PUAC recommended reducing the minimum sewer charge from four units to two units. The reduction in the minimum charge has an essential use affordability benefit, and also incentivizes indoor water use efficiency. The RAC and PUAC recommended retaining the existing customer class volumetric rate structure by volume and strength of wastewater flow, which helps address interclass equity goals. Rates for each class increase due to the updated cost of service analysis, and the reduction of the minimum sewer charge.

PUBLIC PROCESS:

A major component of the Rate Study was public engagement through the formation of the RAC. The RAC included citizen representatives, environmental advocacy organizations, commercial and industrial representatives, low-income advocacy groups, and numerous City departments and divisions. The RAC's two overarching purposes were to represent and communicate community values and provide input, including recommendations to the PUAC, Salt Lake City Mayor, and Council. Over six meetings during fall and winter 2017, the RAC developed rate structure alternatives based on the following ranked pricing objectives:

1) Conservation
2) Essential Use Affordability
3) Demand Management

4) Rate Stability
5) Interclass Equity

To meet these objectives, the RAC recommended modifications to the water and sewer rate structures. The RAC provided their recommendations to the PUAC at the January 8, 2018 meeting. During the January 25, 2018 PUAC meeting, committee members finalized their recommendation to the administration. These recommendations are presented in the Rate Study. Public Utilities then presented the Rate Study's recommended structural changes to the water and sewer rates to the City Council during the October 2nd, 2018 work session.

EXHIBITS:

Exhibit A: Proposed Salt Lake City Ordinance Adopting New Water and Sewer Rate Structures

Exhibit B: Executive Summary of the Salt Lake City Department of Public Utilities Comprehensive Water, Sewer, and Stormwater Rate Study

Exhibit A

Proposed Salt Lake City Ordinance Adopting New Water and Sewer Rate Structures

SALT LAKE CITY ORDINANCE
No. of ____ 2019

(Adopting New
Water and Sewer Rate Structures)

WHEREAS, Salt Lake City Department of Public Utilities convened a Rate Advisory Committee comprised of community representatives and stakeholders, and completed a Comprehensive Water, Sewer, and Stormwater Rate Study in 2018;

WHEREAS, as part of the 2018 Rate Study, the Rate Advisory Committee and the Public Utilities Advisory Committee recommended changes in the structure of water and sewer rates to meet primary objectives of conservation, essential water use affordability, water demand management, rate stability, and interclass equity;

WHEREAS, the key structural changes reflecting the above objectives include: (1) changing water rates from a system-wide cost of service basis to a class cost of service basis to meet equity and essential water use affordability goals; (2) reduction of the block four threshold to meet conservation and demand management goals; and (3) reduction of the sewer minimum charge to meet essential water use affordability goals;

WHEREAS, a new rate for secondary irrigation water was established, including an inclining rate block structure, to facilitate the use and conservation of secondary irrigation water at certain Salt Lake City parks and golf courses

WHEREAS, the Salt Lake City Consolidated Fee Schedule is proposed to be amended to incorporate new water and sewer rate structures in coordination with approval of Public Utilities' Fiscal Year 2019-2020 budget; and

WHEREAS, the Salt Lake City Council finds that good grounds exist for updating the calculation of water and sewer rates to better reflect the policies and priorities of the Council and are necessary, reasonable, and equitable.

NOW, THEREFORE, be it ordained by the City Council of Salt Lake City, Utah:

SECTION 1. The Salt Lake City Consolidated Fee Schedule shall be amended, in pertinent part, to reflect changes to water and sewer rate structures in coordination with approval of Public Utilities' Fiscal Year 2019-2020 Budget.

SECTION 2. This ordinance shall become effective on the date of its first publication.

Passed by the City Council of Salt Lake City, Utah this __ day of ______, 2019.

____

CHAIRPERSON

ATTEST:

____

CITY RECORDER

Transmitted to Mayor on ______________________.

Mayor's Action: _________ Approved. ___________ Vetoed.

____

MAYOR

____

CITY RECORDER

APPROVED AS TO FORM

Date: 4-5-19

By: ER Vetta

(SEAL)

Bill No. _______ of 2019.

Published: ___________________

HB_ATTY-#76899-v1-Water_&_Sewer_Rate_Changes_Ordinance_4-5-2019_

Exhibit B

Executive Summary of the Salt Lake City Department of Public Utilities Comprehensive Water, Sewer, and Stormwater Rate Study

SALT LAKE CITY DEPARTMENT OF PUBLIC UTILITIES

Comprehensive Water, Sewer, and Stormwater Rate Study

Draft-Final Report / July 17, 2018

* Executive Summary and Secondary water rate summary

RAFTELIS

5619 DTC Parkway
Suite 850
Greenwood Village, CO 80111

Phone 303.305.1135

www.raftelis.com

RAFTELIS

July 16, 2018

Ms. Laura Briefer
Director of Public Utilities
Salt Lake City Department of Public Utilities
1530 South West Temple
Salt Lake City, UT 84115

Subject: Comprehensive Water, Sewer, and Stormwater Rate Study

Dear Ms. Briefer,

Raftelis is pleased to provide this 2018 Water, Sewer and Stormwater Rate Study to the Salt Lake City Department of Public Utilities.

The Report details the revenue requirement, cost of service, and rate design analysis used to develop proposed fiscal year 2019 water, sewer, and stormwater rates. This study also includes a review and update to the City's miscellaneous water, sewer, and stormwater fees. As part of this study, the City convened a Rate Advisory Committee (RAC). The RAC was charged with reviewing and providing recommendations to Staff and the Public Utilities Advisory Board (PUAC) on water and sewer rate structure alternatives. The RAC's final recommendations are discussed in this report along with the PUAC recommendation to City Council.

We would like to thank you, Mr. Brad Stewart, Mr. Kurt Spjute and the members of the RAC for their assistance and support during this study. Questions regarding this report and the Study should be direct to Mr. Cristiano or me at the contact information below.

Sincerely,
RAFTELIS, INC.

Richard D. Giardina   Todd Cristiano

Rick Giardina
Executive Vice President
rgiardina@raftelis.com
303-305-1136

Todd Cristiano
Manager
tcristiano@raftelis.com
303-305-1138

TABLE OF CONTENTS

LIST OF TABLES

LIST OF APPENDICES

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1. EXECUTIVE SUMMARY

1.1 Introduction

The Salt Lake City Department of Public Utilities (Department) retained Raftelis to conduct a water, sewer, stormwater rate and miscellaneous fees study. This study included the following:

- Engaging a Rate Advisory Committee (RAC) to provide input and feedback on water and sewer rate structure alternatives to the PUAC.
- Development of revenue requirements for the water, sewer and stormwater utilities for fiscal year (FY)19[1][2].
- Analysis of customer class cost of service for each utility.
- Design of cost-of-service rates and rate alternatives as recommended by the Rate Advisory Committee for FY19.
- Review and update the Department's miscellaneous fees for the water, sewer and stormwater utilities.

Raftelis applied industry standard methodologies supported by the American Water Works Association (AWWA) *Principles of Water, Rates, Fees, and Charges* M1 manual and the Water Environment Federation *Financing and Charges for Wastewater Systems Manual of Practice, No. 27* in the development and design of utility rates.

1.2 Study Findings and Recommendations

1.2.1 Rate Advisory Committee

Department Staff assembled a Rate Advisory Committee to participate in a review of the Department's water and sewer rate structures. Raftelis along with The Langdon Group and Department Staff, facilitated six meetings with the RAC. These meetings included, among other topics, the identification and ranking of pricing objectives, RAC input on alternative rate structures, and the RAC's recommended rate structure for FY19 implementation designed to meet the identified goals and objectives. The results were presented to the Department's Public Utilities Advisory Committee (PUAC) on January 25, 2018 for their review and recommendation to the Mayor and City Council.

Appendix A contains the *2018 Rate Advisory Committee* report summarizing the water and sewer rate structure recommendations. The RAC developed rate alternatives based on the following ranked pricing objectives:

1. Conservation
2. Essential use affordability
3. Demand management
4. Rate stability

---

[1] FY19 is the period from July 1, 2018 through June 30, 2019.

[2] The term 'FY19 Utility Presented' shown in this report are the adopted FY18 rates for water, sewer, and stormwater multiplied by the FY19 proposed revenue adjustment for each utility.

5. Interclass equity
6. Intraclass equity

To meet these objectives, the RAC recommended the following modifications to the water and sewer rate structures:

Water Rate Structure Recommended Alternatives

- Retain the fixed charge by meter size. Modify the price ratio between the meter sizes to reflect capacity potential of each meter size to a ¾" meter. This fixed charge modification is recommended regardless of which volumetric rate alternative is selected.
- The RAC recommended two water volumetric rate structure alternatives using a class-based cost-of-service rate for consideration to the PUAC. Table 1.1 compares the existing rate structure and the alternative rate structures. ***Many alternatives were considered by the RAC. For purposes of this report, the original "names" of the alternatives, as considered by the RAC, have been retained.***

    - ***Alternative #2: COS/Existing Structure Adjusted for COS.*** Retain the fixed-block rate structure for all residential customers and the average winter consumption (AWC)-based rate structure for commercial, institutional and industrial (CII) customers.
        - Reduce the block 4 threshold from 70 hundred cubic feet (ccf) to 60 ccf for the single residence, duplex, and triplex customer classes.
        - Reduce the CII block 4 threshold from 700% of AWC to 600% of AWC.
    - ***Alternative #3: COS/AWC All*** Modify the existing fixed-block structure for single residence, duplex, and triplex to an AWC-based 4 block rate structure, the same structure as CII.
        - Set the single residence, duplex, and triplex customer class block 4 threshold at 600% of AWC.
        - Reduce the CII customer class block 4 threshold from 700% of AWC to 600% of AWC.

Table 1.1: Water – Current and Proposed Rate Structure Alternatives
City and County

Block	Residential(1)			CII(2)	
	FY19 Utility Presented	Alt. #2 COS/Existing	Alt. #3 COS/AWC All	FY19 Utility Presented	Alt. #2/ Alt. #3
Winter Period (Nov-Mar)	Block 1 Rate for All Usage			Block 1 Rate for All Usage	
Summer Rate Structure (April through November)					
Block 1	0-10 ccf	0-10 ccf	0-AWC(3)	0-AWC	0-AWC
Block 2	11-30 ccf	11-30 ccf	AWC-300%	AWC-300%	AWC-300%
Block 3	31-70 ccf	31-60 ccf	300%-600%	300%-700%	300%-600%
Block 4	>70 ccf	>60 ccf	>600%	>700%	>600%

(1) Single residence block 1: 0 to 10 ccf
Duplex block 1: 0 to 13 ccf
Triplex block 1: 0 to 16 ccf
(2) Alternative #2 and Alternative #3 CII rate structures are the same.
(3) AWC = Average Winter Consumption. "AWC – 300%" means usage greater than a customer's AWC and less than or equal to 300% of the customer's AWC.

Sewer Rate Structure Recommended Alternatives

- Retain the customer class volumetric rate structure by volume and strength of wastewater flow for each alternative. Strength categories include biochemical oxygen demand (BOD) and total suspended solids (TSS). The two alternatives recommended are:
  - ***Alternative #1: No Minimum Charge.*** Eliminate the minimum charge. Customers are only charged for their AWC monthly flow.
  - ***Alternative #3: Reduced Minimum Charge.*** Reduce the minimum charge allowance from 4 ccf to 2 ccf. This reduces the minimum charge by approximately 43 .

Table 1.2 shows the existing sewer rate structure. The proposed structure remains unchanged from the existing.

Table 1.2: Sewer – FY19 Utility Presented and FY19 Proposed Raftelis Rate Structure

<table>
<tr><th>Class[1]</th><th>BOD Strength mg/l</th><th>TSS Strength mg/l</th><th>Flow $ per ccf</th><th>BOD $ per ccf</th><th>TSS $ per ccf</th></tr>
<tr><td>1</td><td>0 - 300</td><td>0 - 300</td><td colspan="3">Applies to Existing and All Alternatives</td></tr>
<tr><td>2</td><td>300 - 600</td><td>300 - 600</td><td rowspan="5">Same volume rate for all classes</td><td rowspan="5">Volume rate varies by BOD strength</td><td rowspan="5">Volume rate varies by TSS strength</td></tr>
<tr><td>3</td><td>600 - 900</td><td>600 - 900</td></tr>
<tr><td>4</td><td>900 - 1,200</td><td>900 - 1,200</td></tr>
<tr><td>5</td><td>1,200 - 1,500</td><td>1,200 - 1,500</td></tr>
<tr><td>6</td><td>1,500 - 1,800</td><td>1,500 - 1,800</td></tr>
<tr><td>7</td><td>>1,800</td><td>>1,800</td><td colspan="3">Special Rate by Customer</td></tr>
<tr><td colspan="6">(1) Customers in classes 1 through 6 are billed monthly based on their average winter consumption (AWC) times the sum of the rates for flow, BOD, and TSS rates or a minimum charge whichever is greater. AWC is the average of water usage for the months November through March.</td></tr>
</table>

1.2.2 Public Utilities Advisory Committee

Staff presented the water and sewer alternatives at the PUAC's January 25, 2018 meeting. The PUAC recommended the following:

- Water:
  - Monthly fixed charge: Varies by meter size; capital costs by meter size varies by on meter capacity ratios.
  - Volume rate structure: Alternative #2: COS/Existing Structure Adjusted for COS
- Sewer: Alternative #3: Reduced Minimum Charge

The remainder of this report will show the proposed water and sewer rates under these alternatives. The term "proposed rates" refers to rates based on the recommended rate structure alternatives from the PUAC.

1.2.3 Water Rate Study

FY19 Proposed Raftelis water rates for were developed based on the following:

- A system-wide 4% revenue increase over FY18
- Customer class cost-of-service analysis
- Rate structure recommendations from the RAC and final recommendations from the PUAC

Fixed Charge

The proposed fixed charge varies by meter size. The fixed charge recovers the following costs: meter reading/billing, customer service, and a portion of capital costs. Meter reading, billing and customer service costs do not vary by meter size. Capital costs increase as meter size increases recognizing the additional costs to serve larger capacity customers. The capital cost differential by

meter size is based on the ratio of the maximum allowable flow capacity to a ¾" meter. Table 1.3 shows the FY19 Utility Presented and FY19 Proposed Raftelis fixed charges.

Table 1.3: Water – FY19 Utility Presented and FY19 Proposed Raftelis Fixed Charges(1)

Meter Size	FY19 Utility Presented	FY19 Proposed Raftelis	Change - $	Change - %
3/4"	$9.89	$8.84	($1.05)	(11%)
1"	9.89	11.56	1.67	17%
1 ½"	11.68	18.37	6.69	57%
2"	12.68	26.55	13.87	109%
3"	21.28	48.34	27.06	127%
4"	22.78	72.86	50.08	220%
6"	32.88	140.98	108.10	329%
8"	59.11	222.71	163.60	277%
10"	109.63	576.91	467.28	426%

(1) County fixed charges are 1.35 times City fixed charges.

Volume Rates

The proposed volume structures for residential and commercial (CII) retains the 4-block inclining structure. The irrigation volume structure retains the 3-block inclining structure. The residential rate structure is a fixed block structure while the commercial or CII class is an individualized structure. Residential rates include single residence, duplex, and triplex classes. CII includes commercial, industrial, and institutional customers. The CII structure's thresholds are based on each customer's average winter consumption (AWC). The irrigation structure retains the individualized target budget-based structure. The volume rates developed in this study are based on each class' cost of service. Table 1.4 shows the FY19 Utility Presented and FY19 Proposed Raftelis rates.

Table 1.4: Water – FY19 Utility Presented and FY19 Proposed Raftelis Residential Volume Rates(1) City Customers

Block	FY19 Utility Presented $ per ccf	FY19 Proposed Raftelis $ per ccf	Change - $	Change - %
RESIDENTIAL(2)				
		Winter (November - April)		
All Usage	$1.35	$1.30	($0.05)	(3.7%)
		Summer (April - October)		
1	$1.35	$1.30	($0.05)	(3.7%)
2	1.85	1.78	(0.07)	(3.8%)
3	2.57	2.47	(0.10)	(3.9%)
4	2.74	2.63	(0.11)	(4.0%)
COMMERCIAL				
		Winter (November - April)		
All Usage	$1.35	$1.42	$0.07	5.2%
		Summer (April - October)		
1	$1.35	$1.42	$0.07	5.2%
2	1.85	1.94	0.09	4.9%
3	2.57	2.70	0.13	5.1%
4	2.74	2.87	0.13	4.7%
IRRIGATION				
		Winter (November - April)		
All Usage	1.85	1.71	($0.14)	(7.6%)
		Summer (April - October)		
1	$1.85	1.71	(0.14)	(7.6%)
2	2.57	2.38	(0.19)	(7.4%)
3	2.74	2.53	(0.21)	(7.7%)

(1) County rates are 1.35 times City rates

(2) Includes single residence, duplex, and triplex. See Table 1.1 for the block thresholds for each class.

1.2.4 Sewer Rate Study

FY19 Proposed Raftelis sewer rates were developed based on the following:

- A system-wide 15% revenue increase
- Customer class cost-of-service analysis
- Rate structure recommendations from the RAC and final recommendations from the PUAC

The FY19 Proposed Raftelis sewer structure and rates retain the customer class by sewer strength classification. The customer classes are assessed unit charges ($ per ccf) for flow, BOD, and TSS. Table 1.5 summarizes the FY19 Utility Presented and FY19 Proposed Raftelis rate structure and rates.

Table 1.5: Sewer - Comparison of FY19 Utility Presented and FY19 Proposed Raftelis Rates

Class	BOD Strength mg/l	TSS Strength mg/l	FY19 Utility Presented(1)	FY19 Proposed Raftelis(2)	Change - $	Change - %
1	0 – 300	0 – 300	$3.05	$3.11	$0.06	2.0%
2	300 – 600	300 – 600	3.97	4.05	$0.08	2.0%
3	600 – 900	600 – 900	5.37	5.47	$0.10	1.9%
4	900 – 1,200	900 – 1,200	6.79	6.88	$0.09	1.3%
5	1,200 – 1,500	1,200 – 1,500	8.13	8.24	$0.11	1.4%
6	1,500 – 1,800	1,500 – 1,800	9.53	9.64	$0.11	1.2%
7	>1,800	>1,800		*Special Rate by Customer*		
Extra Strength Rates, $ per lb						
Chemical oxygen demand (COD)			$0.221	$0.356	$0.135	61.3%
Biochemical oxygen demand (BOD)			0.442	0.713	$0.271	61.3%
Total suspended solids (TSS)			0.264	0.451	$0.187	70.9%

(1) Customers in classes 1 through 6 are billed monthly based on their average winter consumption (AWC) times the sum of the flow rates for flow, BOD, and TSS or a minimum charge of $11.93 whichever is greater. AWC is the average of water usage for the months November through March.

(2) Customers in classes 1 through 6 are billed monthly based on their average winter consumption (AWC) times the sum of the flow rates for BOD, and TSS rates or a minimum charge of $6.82 whichever is greater. AWC is the average of water usage for the months November through March.

1.2.5 Stormwater Rate Study

Table 1.6 shows compares the FY19 Utility Presented and FY19 Proposed Raftelis stormwater fees. There is no change to the structure for FY19.

Table 1.6: Stormwater - Comparison of FY19 Utility Presented and FY19 Proposed Raftelis Rates

Customer Class	FY19 Utility Presented	FY19 Proposed Raftelis	Change $	Change %
1 or 2 Units < .25 acres	$4.94	$4.94	$0.00	0.0%
1 or 2 Units > .25	6.91	6.91	0.00	0.0%
3 or 4 Units	9.88	9.88	0.00	0.0%
Impervious Area Based	5.43	5.43	0.00	0.0%

1.2.6 Miscellaneous Fees Study

The Department assesses fees for various goods and services associated with providing water, sewer, and stormwater service. These goods and services directly benefit the customer requesting the service. As such, these costs are passed directly to the customer rather than through all rate payers. Raftelis reviewed selected fees from the water, sewer, and stormwater utilities, proposed updates and also evaluated new fees for the utilities. The existing and proposed fees can be found in Section 7 of this report. The fee categories reviewed include:

- Water connection fees
- Meter inspection and testing
- Fire hydrant maintenance fees
- Flat water charge – City and County Agencies
- Pressure testing
- Disconnection
- Plan review fees
- Sewer inspections/Industrial wastewater discharge permits
- Stormwater inspection fees
- Stormwater discharge permits

Table 3.12: Water – FY19 Typical Monthly Summer Bills - Single Residence City Customers

Usage ccf	FY19 Utility Presented	FY19 Proposed Raftelis	Change ($)	Change (%)	% of Summer Bills
0	$9.89	$8.84	($1.05)	(10.6%)	4.8%
5	16.64	15.34	(1.30)	(7.8%)	23.1%
10	23.39	21.84	(1.55)	(6.6%)	18.5%
20	41.89	39.64	(2.25)	(5.4%)	19.5%
30	60.39	57.44	(2.95)	(4.9%)	12.2%
40	86.09	82.14	(3.95)	(4.6%)	7.7%
50	111.79	106.84	(4.95)	(4.4%)	4.8%
60	137.49	131.54	(5.95)	(4.3%)	3.0%
70	163.19	157.84	(5.35)	(3.3%)	1.9%

3.12 Secondary Irrigation Water Rate

The Department requested a review and update of the secondary irrigation water rate for select golf courses and parks. This secondary water service is to the culinary irrigation water demands of select sites. The cost to provide this service includes an annual return on the Department's water resources cost and a water delivery cost.

The secondary irrigation water rate follows the same inclining block volume rate structure as the culinary irrigation-only meter rate. Each customer is provided a monthly budget based on the following factors: permeable area, historical evapotranspiration and standard watering practices. Water use within the budget is charged at a rate comparable to Block 2 of the standard residential rate (a block established to reflect reasonable outdoor use). Water use that exceeds the budget is charged in the higher blocks. It is hoped the structure provides incentive for wise use of water. Table 3.13 on the next page shows the summary calculation. Detailed calculations are contained in the appendix.

Table 3.13: Water - Secondary Irrigation Water Rate Calculation

Annual Costs	Units	Unit Cost $ per AF	Unit Cost $ per ccf
Annual return water resource costs	$5,194,331		
Reliable Water Supply, Acre-Feet (AF)	115,713		
Water resource unit cost, $ per AF		$44.89	$0.10335
Water delivery cost	$1,641,658		
Projected volume, AF	14,009		
Water delivery cost, $ per AF		$117.19	
Total, $ per AF		**$162.08**	**$0.37315**
Rate Structure, $ per AF			
Block 2		$162.08	37.3 cents
Block 3		307.95	71.4 cents
Block 4		623.01	$1.434




SALT LAKE CITY DEPARTMENT OF PUBLIC UTILITIES
RENEWABLE ENERGY STUDY CONTRACT No.51360066

SALT LAKE CITY RENEWABLE ENERGY PLAN

Energy Strategies, Sunrise Engineering, Utah Clean Energy, Carollo Engineers
Consulting Team

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1.0 EXECUTIVE SUMMARY

The Salt Lake City Department of Public Utilities (DPU) is striving to reduce its reliance on electricity generated from fossil fuels as it provides essential services to its customers. To achieve these objectives, DPU seeks to diversify its energy portfolio through the development of renewable resources on Salt Lake City and DPU owned and managed properties, including solar photovoltaic (PV) systems, hydroelectric, cogeneration, wind power, and wastewater heat recovery systems. To support this goal, DPU selected a consultant team to conduct a renewable energy feasibility assessment and create this renewable energy plan. The projects described in this report offer DPU the opportunity to harness the sun, wind, and water to generate clean electricity. By exploring these renewable energy projects now, DPU will be prepared to adapt to future trends and needs and to improve its operations city-wide.

DPU selected a consultant team headed by Energy Strategies and including Sunrise Engineering, Utah Clean Energy, and Carollo Engineers, collectively referred to as the “Consultant Team,” to conduct the renewable energy feasibility assessment. The Consultant Team members have extensive experience helping private companies, institutions of higher education, and government agencies evaluate the technical, economic and regulatory feasibility of renewable energy and other clean energy technologies.

This study consisted of three sequential phases: a Preliminary Site Scoping Evaluation (Phase I), a Site-Specific Evaluation (Phase II), and a detailed evaluation of six potential project sites, including a regulatory assessment, an economic analysis, and recommendations for funding mechanisms and resources for each project (Phase III).

Phase I Preliminary Scoping Evaluation

DPU provided a list of 151 properties which were identified as potential sites for renewable energy projects. All 151 sites were screened and those found not to be suitable for a renewable energy project were eliminated. The remaining 42 sites were ranked using a screening matrix based on six criteria: suitability of the site for a renewable energy project, interconnection opportunities, zoning compatibility, permitting, and generation potential. Although not all 42 sites were ultimately reviewed in the Phase II analysis, many of these sites could support a viable renewable energy project. Combined, these sites could generate 18,779 megawatt-hours (MWh) of renewable energy.

Salt Lake City completed a 1 MW solar photovoltaic farm on a former landfill site at 1955 West 500 South in 2014. Existing incentives for solar, including a 30% federal tax credit which expires in 2016, can reduce the upfront expense of installing panels. DPU has the opportunity to install a solar farm more than three times the size of the landfill solar farm at the Terminal and Park Reservoirs.

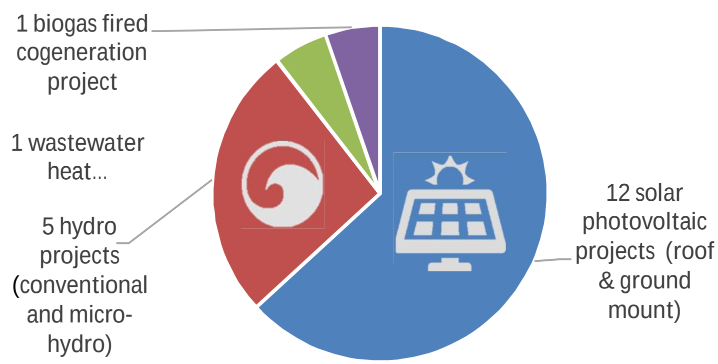
Phase II Site-Specific Evaluation

The results of the Phase I screening evaluation were presented to DPU for review and 19 sites were selected for more detailed evaluation in Phase II. These sites were chosen for further screening based on their score in Phase I screening matrix, because they provide opportunities for DPU to evaluate innovative technologies, or for both reasons. The 19 selected sites included:

- The 14 highest-scored sites from the Phase I analysis,
- 3 solar PV sites which received lower scores due to smaller generation potential but scored well in other categories,
- 2 projects that were not scored because further analysis was required: a wastewater heat recovery project at the West Temple trunkline and a cogeneration project at the Salt Lake City Water Reclamation Facility.

Combined, these projects could generate 13,690 megawatt hours of electricity, enough to offset approximately 44 percent of the electricity currently purchased by DPU from Rocky Mountain Power (RMP) and Murray City Power.

Figure 1-1. Projects Evaluated in Phase II



Conclusions and Recommendations of the Phase II Regulatory and Economic Analysis

From this group of 19 projects, DPU selected a representative cross-section of six projects to undergo a more detailed evaluation including regulatory assessment and economic analysis. A sixth project, wastewater heat recovery, was originally included in the Phase III detailed analysis. The wastewater heat recovery technology proved to be incompatible with the existing Central Heating Plant, so a demonstration project at the West Temple Trunkline was included in the analysis instead. The combined estimated overnight capital cost for the two solar photovoltaic (PV) and two hydroelectric projects is $14.8 million, and these four projects would be able to generate 6,287 MWh of electricity, and avoid 4,735 $MTCO_2e$ of greenhouse gas (GHG) emissions.

Table 1-1. Sites Included in Phase III Detailed Analysis

Site	Technology	Capacity (kW)	Benefit
Salt Lake City Water Reclamation Facility	Biogas Cogeneration	1,400	Use biogas to produce electricity; reduce the amount of biogas which is flared; offset purchases from RMP.
West Temple Trunkline	Wastewater Heat Recovery	N/A	Recover heat from wastewater; reduce natural gas consumption
15th East Reservoir[1]	Roof-mounted Solar PV	274	Produce electricity
Mountain Dell Dam	Hydroelectric	260	Produce electricity
Terminal & Park Reservoirs	Roof-mounted Solar PV	3,488	Produce electricity
Pressure Reducing Valve Station B11-R13	Hydroelectric Reverse-pump Turbine	190	Produce electricity

Regulatory Analysis:

The regulatory and financing assessment identified regulatory barriers and optimal rate schedules for each of the six Phase III sites in addition to various financing options available for each of the projects. While some of the rate options discussed are available now, others are currently under review by the Utah Public Service Commission (PSC). For those rates that are currently under review by the PSC, it is recommended that DPU continue to monitor the proceedings until new rates will be finalized.

A primary question asked regarding each potential site was whether electricity production from a renewable energy project at the site would exceed electricity usage at the site. Utah's net metering policy allows a facility to receive a credit for electricity produced on-site which can be used to offset purchases of electricity from the utility. However, electricity produced in excess of total annual usage is forfeited without compensation. If a renewable energy project produces more electricity than is

[1] Although a 274-kW solar installation was evaluated at the 15th East Reservoir, a smaller installation of approximately 25-kW could entirely offset electric usage on-site and potentially improve the economic viability of this project.

used on-site annually, the facility must contract to sell the excess electricity at wholesale rates or else forfeit it. Whether or not a facility is able to use the electricity on-site or must sell it obviously impacts the overall economics of the renewable energy project. Virtual net metering and selling excess electricity to the grid can help offset the capital investment in a renewable energy project.

While the Consultant Team recognizes it is DPU's preference to internally fund renewable energy projects using revenue from its utility operations, there are opportunities to leverage DPU's available funds with other funding sources to accelerate the deployment of City-owned renewable energy projects. All of the funding sources and financing mechanisms identified are viable options for lowering the upfront capital investment required by DPU. Moreover, from the perspective of DPU, lowering the capital investment will improve the economics of projects.

Economic Analysis:

Each project underwent an economic analysis which compared the projected cost of utility service at a given site to the potential savings DPU could capture by producing renewable energy. The economic value of each project was expressed as Net Present Value (NPV). First, each site was assessed using current regulatory and economic assumptions, including utility prices which are predicted to increase modestly over time. Next, two costs-of-carbon sensitivities were run to account for costs associated with future GHG regulations.[2] Assumed costs were \$25/MTCO_2e and \$50/MTCO_2e. Finally, one more sensitivity analysis was run assuming electricity generated by the pressure reducing valve project and the Terminal and Park Reservoirs solar PV project could be used to offset electricity consumed at other DPU facilities through virtual alternative net metering arrangement (which is not currently available in Utah). The results of the economic analysis are summarized in Table 1-2.

Summary and Conclusions

A detailed analysis of each of the six selected projects is provided in this report: table 9-1 provides an economic ranking of all six projects under several different regulatory scenarios, and table 9-2 ranks all six energy projects based on their potential to reduce DPU's greenhouse gas footprint. DPU must weigh several different factors when prioritizing amongst the projects presented in this report, including the economic analysis, the estimated avoided greenhouse gas emissions, the feasibility of each project, and other potential benefits of a project (such as increasing the visibility of Salt Lake City's energy initiatives). A summary of each project is provided below, including challenges associated with the project and recommendations for cost-effective completion, should DPU choose to pursue that project.

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[2] Federal agencies measure the potential impact of carbon emission regulations by assigning a cost to CO_2 emissions, represented as \$/megaton of carbon dioxide or carbon dioxide equivalent. This figure is used both to estimate the economic damages associated with an increase in carbon dioxide (CO_2) emissions and the value of a reduction in CO_2 emissions. The EPA has selected four Social Cost of Carbon values for use in regulatory analyses, representing various assumed discount rates. The most recent estimates for these values are available at http://www.epa.gov/climatechange/EPAactivities/economics/scc.html.

Table 1-2. Summary of Economic Analysis

Site	Technology	Rate Schedule	Overnight Capital Cost	Non-Fuel Operating Expense	Levelized Cost	Net Present Value compared to Cost of Utility Service ($Millions)		
			2014$ Millions	2014$ Millions	$ per MWh	$0 per $MTCO_2e$	$25 per $MTCO_2e$	$50 per $MTCO_2e$
Salt Lake City Water Reclamation Facility	Biogas Cogeneration (no BNR, no Nat. Gas)	Sch. 31 (9)	$0.00	$76.579	$25.60	($1.458)	($1.996)	($2.533)
	Biogas Cogeneration (BNR, Nat. Gas)	Sch.31 (9)	$0.00	$123.907	$61.50	$3.112	$3.468	$3.824
15th East Reservoir[3]	Roof-mounted Solar PV	Net metered	$0.920	$0.013	$153.50	$0.426	$0.314	$0.202
West Temple Trunkline	Wastewater Heat Recovery	N/A	$0.695	$0.000	N/A	$0.695	$0.584	$0.566
Mountain Dell Dam	Hydroelectric	Net metered	$1.551	$0.019	$92.00	$0.355	$0.064	($0.228)
Terminal & Park Reservoirs[3]	Roof-mounted Solar PV	Sch. 37	$11.292	$0.150	$139.50	$10.155	$8.699	$7.242
		Net metered			$139.50	$2.354	$0.898	($0.559)
Pressure Reducing Valve Station B11-R13	Hydroelectric Reverse-pump turbine	Sch. 37	$0.999	$0.015	$55.50	$0.585	$0.258	($0.068)
		Net metered			$55.50	($0.188)	($0.515)	($0.841)

Several projects rise to the top because they offer DPU attractive opportunities to reduce its environmental impact and the risk associated with carbon regulations while also lowering operations costs. If DPU were able to use electricity produced by one renewable energy project to offset electricity consumption at a different DPU site, either through virtual net metering or another, alternative net metering arrangement, savings associated with some projects would increase significantly. Although grants and financing mechanisms were not evaluated in the economic

[3] Costs and NPV are for a turnkey project without using a power purchase agreement (PPA) or other incentives. For solar PV projects, a PPA or prepaid lease structure would allow DPU to take advantage of a federal tax incentive through third-party ownership and could result in significant upfront cost reductions (up to 30percent). A PPA can be structured such that ownership reverts to DPU after tax advantages are fully utilized. In the case of the 15th East Reservoir, although a 274-kW solar installation was evaluated at the 15th East Reservoir, a smaller installation of approximately 25-kW could entirely offset electric usage on-site. Financial incentives to install a larger system are limited and the NPV would improve if the system were sized to meet the electricity needs of the on-site facility.

analysis, they would significantly reduce the overnight capital cost of several projects. For example, using a power purchase agreement (PPA) for solar photovoltaic installations allows DPU to realize savings of up to 30 percent due to a federal tax incentive for solar. Similar savings are achieved if DPU were to receive an incentive through the Utah Solar Incentive program. A portfolio of available financing options is described in Chapter 8, including the Blue Sky Grant Program, Qualified Energy Conservation Bonds, the U-Save Energy Program, the Utah Solar Incentive Program, and PPAs. Table C summarizes the challenges and recommendations associated with each project.

Salt Lake City Water Reclamation Facility

At the Salt Lake City Water Reclamation Facility, two cogeneration engines already exist and are used to convert excess biogas into clean energy. However, the current rate schedule at the facility does not allow for the sale of excess electricity to the grid, so the engines are not both operated at the same time for fear that they will produce excess energy. Switching to a rate schedule which does allow for the sale of excess electricity to the grid would allow DPU to operate both engines concurrently, burn more waste biogas, and produce more clean electricity to offset on-site electricity use. In the future, DPU may be required to convert to a Bio Nutrient Removal (BNR) process, which will reduce the amount of excess biogas production while also increasing electricity usage. Although the NPV of biogas cogeneration is negatively impacted by a BNR process, DPU could better utilize existing cogeneration engines with no infrastructure upgrades until required to switch to a BNR process.

The Salt Lake City Water Reclamation Facility uses cogeneration engines to convert waste biogas into clean electricity. By switching to a rate schedule that allows the Water Reclamation Facility to export excess power to the grid, the Facility could operate the existing cogeneration engines more frequently, make use of more waste biogas, and produce more clean energy.

Mountain Dell Dam

A hydroelectric turbine at the existing Mountain Dell Dam could be used to generate power to offset on-site electricity usage and poses no significant technical or regulatory challenges. If the future regulatory costs of carbon regulation are assumed to be \$50/MTCO$_2$e, a hydroelectric turbine at the Mountain Dell Dam has an attractive NPV.

B11-R13 Pressure Reducing Valve (PRV)

A micro-hydroelectric turbine at the B11-R13 PRV could produce electricity from the energy that is generated when the pressure in water pipelines is reduced before it is delivered to homes and

businesses. The NPV of this site is attractive if the site were able to virtually net meter and electricity produced at this PRV could be used to offset DPU load at other facilities. Virtual net metering is not currently available in Utah and there is no significant load at the PRV itself, so the electricity could instead be sold to the grid. The NPV of the project is still attractive even without virtual net metering when future carbon costs are assumed to be $50/MTCO_2e.

Terminal and Park Reservoirs

A large solar photovoltaic installation at these reservoirs could produce a significant amount of clean energy, however there is minimal DPU load on-site. If virtual net metering were available it would improve the NPV of this project significantly. Although leases and PPAs were not considered in this analysis, a lease or PPA would allow DPU to take advantage of a federal tax incentive through a third-party ownership structure and could result in significant upfront cost reductions (up to 30 percent). A PPA can be structured such that ownership reverts to DPU after tax advantages are fully utilized, and using a PPA would also significantly impact the assumed NPV. Notably, this project has the potential for the biggest environmental impact. Solar photovoltaic panels could produce enough electricity to offset 3,381 $MTCO_2e$ of emissions associated with utility electricity. This represents approximately 13 percent of the GHG emissions associated with DPU's consumption of purchased electricity and natural gas.

Reservoirs can be used to produce clean energy in several different ways. A hydroelectric turbine at the existing Mountain Dell Dam could be used to generate power and offset on-site electricity usage. Solar photovoltaic panels can be sited on top of enclosed reservoirs, such as the 15th East Reservoir and the Terminal and Park Reservoirs, so that otherwise un-utilized real estate can become a source of clean electricity.

15th East Reservoir

A 274-kW solar installation was evaluated at the 15th East Reservoir which would produce an average of 335,000 kWh of electricity each year. However, electricity meters located at this site report that the on-site load is only 70,000 kWh of electricity each year. A smaller 25-kW installation at this site could net meter and offset on-site electricity usage, however this option was not evaluated. Although DPU could build a 274-kW installation, as evaluated in this study, and contract to sell the excess electricity, a smaller net metered solar installation will offer a more attractive NPV. A lease or a PPA, which was not considered in this evaluation, would allow DPU to take advantage of a federal tax incentive through a third-party ownership structure and could result in upfront cost reductions of up to 30 percent.

Salt Lake City Wastewater Heat Recovery

Wastewater heat recovery at a site located adjacent to DPU's main office in Salt Lake City would utilize a heat exchanger to extract heat from wastewater flowing in the sewer trunkline along West Temple and provide space heating to DPU's main office. Although this project would allow DPU to reduce natural gas purchases, it would increase electricity usage. Even when the cost of carbon regulation is assumed to be \$50/MTCO_2e, the NPV of the cost of utility service of the wastewater heat recovery system is estimated to exceed the value of natural gas service provided by Questar over the 30 year-life of the project.

Table 1-3. Summary of Recommendations

Site	Technology	Summary	Challenges	Recommendations
Salt Lake City Water Reclamation Facility	Biogas Cogeneration	Best and most cost-effective opportunity for DPU to generate renewable electricity. A change in operations of engines would enable SLCWRF to burn additional biogas or NG and generate at least 50 percent more electric power.	• Federal water quality standards may require DPU to switch to a bio-nutrient removal (BNR) process in the future. • Existing tariff schedule does not allow generation to exceed load at the site.	• Make operational changes to increase capacity factor of engines and more effectively utilize biogas from site • Evaluate benefits of implementing a FOG program to increase biogas production • Evaluate whether SLCWRF can move to a different rate schedule that would enable it to sell excess electricity back to RMP.
	Biogas Cogeneration (BNR, NG)	Bio-nutrient removal process (BNR) may be required in the future and will have a negative impact on biogas production and make the existing cogeneration system uneconomic.	• Changing to a BNR process will use more electricity and produce less biogas as a byproduct	• If required to switch to BNR process, explore viability of supplementing biogas production by implementing a FOG program.
15th East Reservoir	Roof-mounted Solar PV	Excellent candidate for roof mounted solar PV technology. Limited load at the site makes a 274 kW system uneconomic however economics would improve significantly with a 25 kW system designed to meet site load.	• Minimal electricity usage on site • Unfavorable QF power purchase rates	• Additional analysis should be conducted by DPU to evaluate viability of installing smaller capacity system designed to meet load. • Explore economics of RMP grants and entering into a third party PPA or lease structure to significantly reduce up front capital cost and take full advantage of 30% federal tax credit
West Temple Trunkline	Wastewater Heat Recovery	At this site and given the technology configuration evaluated, the project is uneconomic and would offset natural gas consumption but increase electricity use.	• Low natural gas and electricity prices. • There are many more economically viable renewable energy projects at DPU owned sites.	• A technology demonstration should be considered if other partners, i.e. Questar or RMP, can be found to offset the upfront capital investment a technology demonstration project could be viable.
Mountain Dell Dam	Hydroelectric	An attractive site for renewable energy development because of the ease of interconnection, potential to offset 75% of load and it is eligible for net metering.		• This project is an excellent candidate to for development in the next 5 years. • Evaluate alternative financing options such as a PPA or lease to improve the economics
Terminal & Park Reservoirs	Roof-mounted Solar PV	Solar PV at this site has the potential to produce a large amount of renewable energy and offset GHG emissions.	• $11.3 million capital costs • Unfavorable QF power purchase rates and minimal site load make this project uneconomic	• Evaluate the use of a PPA or lease financing arrangement to take advantage of federal tax credits and apply to the Utah Solar Incentive Program to significantly improve the economics of the project. • Negotiate with RMP to allow this project to offset load at other DPU loads at full retail price.
Pressure Reducing Valve Station B11-R13	Hydroelectric Reverse-pump turbine	Significant RE generation potential. Cost effective when $50 price for carbon included in financial analysis. Attractive technology that can be used at numerous sites on SLC water delivery system.	• Most PRVs have minimal on-site load • Low QF power purchase terms	• Negotiate with RMP to allow this project to offset load at other DPU loads at full retail price. • Economics could be improved by adopting alternative financing approaches.

2.0 INTRODUCTION

2.1 Background

In early 2013, Salt Lake City introduced its *Sustainable Salt Lake – 2015 Plan*, a roadmap designed to enhance Salt Lake City's resiliency, vitality, and sustainability. The plan lays out key goals and strategies for Salt Lake City regarding renewable energy and GHG reductions, including a long-term goal to transform all Salt Lake City municipal facilities into "net zero" energy users. Short-term strategies include increasing renewable energy generation on Salt Lake City's municipal facilities to 2.5-MW and supporting the installation of 10-MW of photovoltaic solar on buildings in the Salt Lake metropolitan area, both by 2015. Reaching these targets will help Salt Lake City reach its 2015 climate change goals to reduce GHG emissions attributed to city buildings and fleet by 13 percent by 2015.

The Salt Lake City Department of Public Utilities (DPU) provides drinking water, wastewater treatment, and other essential services to residents and visitors of the Salt Lake Valley. In line with its mission to serve the Salt Lake Valley and also protect our environment, - DPU is striving to reduce its reliance on electricity generated from fossil fuels and diversify its energy portfolio through the development of renewable energy resources.

DPU has already taken steps towards incorporating more sustainable energy practices in its operations: a significant portion of DPU's water distribution system is designed to rely on gravity rather than electric pumps. Methane produced by anaerobic digesters at the Salt Lake City Water Reclamation Facility (SLCWRF) on average generates six million kWh of electricity per year. The electricity from this cogeneration system is used to power treatment plant operations, and preliminary assessments suggest there is excess digester capacity at the facility. In addition, DPU has examined other renewable energy options, including micro-hydroelectric opportunities in its water distribution system, and DPU and Salt Lake City properties that are potentially suitable for solar photovoltaic (PV) systems.

DPU is interested in expanding its efforts to develop renewable energy and reduce its reliance on electricity generated from fossil fuels as it provides these essential services to its service area and county residents. DPU owns and manages Pressure Reducing Valve (PRV) stations on its water distribution system, water rights, dam sites, a wastewater treatment plant that produces methane, covered reservoirs, building rooftops and other properties that could potentially support renewable energy projects. The access to these sites and the potential availability of wind, solar, biogas and hydroelectric resources presents an opportunity to develop new sources of clean energy, and that could position DPU as a leader in helping Salt Lake City achieve its renewable energy and GHG emissions goals.

In recognition of the opportunity to further develop its renewable energy potential at sites owned by Salt Lake City, DPU issued a Request for Qualifications (November 2013) and a Request for

Proposals (December 2013) Renewable Energy Study RFP No. 51360066, seeking the technical expertise and analysis needed to conduct an evaluation of existing and potential renewable energy projects, and to develop a Renewable Energy Plan for DPU.

2.2 Project Team

To support Salt Lake City's on-going efforts to diversify its energy portfolio and reduce its reliance on carbon-intensive fossil fuels, DPU selected a consultant team headed by Energy Strategies that included Sunrise Engineering, Utah Clean Energy, and Carollo Engineers (Consultant Team) to conduct the renewable energy feasibility assessment. The Consultant Team members have extensive experience helping private companies, institutions of higher education, and government agencies evaluate the technical, economic and regulatory feasibility of renewable energy and other clean energy technologies.

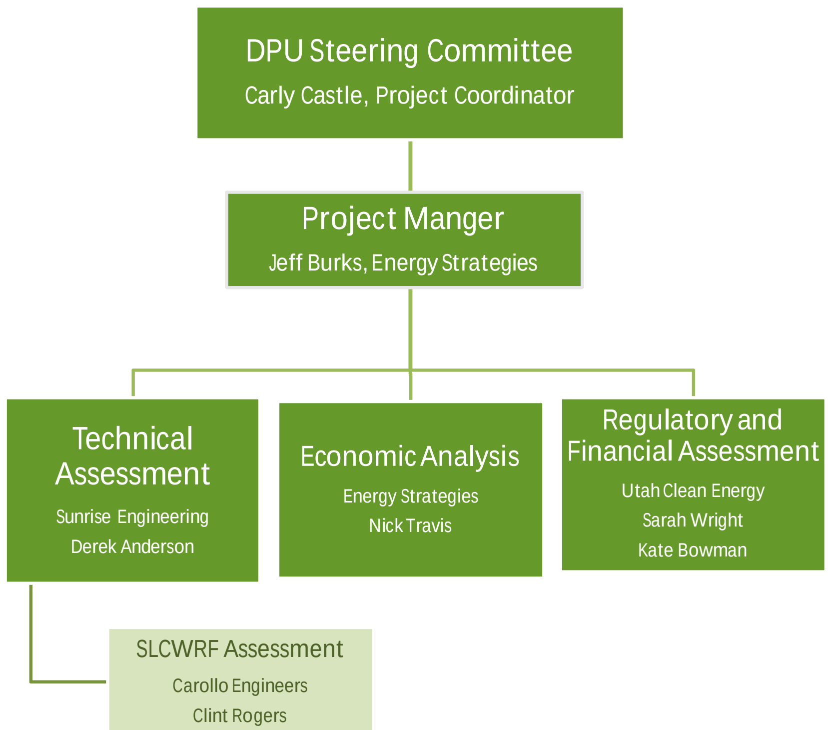
Energy Strategies L.L.C. has conducted over 100 technical, economic, and financial investment analyses and regulatory assessments of utility scale; and distributed renewable energy and co-generation systems for both public and private sector clients. Sunrise Engineering and Carollo Engineers have provided engineering assessments, design, and installation services for numerous small hydroelectric, micro-hydroelectric, biogas-to-energy, wind, and solar projects for both municipal governments and private developers. Utah Clean Energy has worked closely with Salt Lake City on their solar energy, energy efficiency, and climate policy initiatives since 2002, and provides integral experience and proven success within state regulatory and policy arenas to assist in the development and implementation of the Renewable Energy Plan.

In addition to the Consultant Team, Carly Castle, Special Projects Coordinator for DPU, and the DPU Steering Committee rounded out the project team that worked on the renewable energy development planning project. DPU Steering Committee members included:

- Jeff Niermeyer, Director
- Tom Ward, Deputy Director
- Laura Briefer, Deputy Directr
- Tyler Poulson, Program Manager, Division of Sustainability
- Jim Lewis, Finance Manager
- Mark Christensen, Financial Analyst
- Dale Christensen, Water Reclamation Manager
- Giles Demke, Wastewater Plant Maintenance Engineer
- Mark Stanley, Operations and Maintenance Superintendent
- Jesse Stewart, Water Quality Manager

The Consultant Team worked closely with Salt Lake City DPU personnel to ensure that all renewable energy options were identified and to implement a scope of work that would result in an actionable plan. If implemented, the plan will support Salt Lake City and DPU's goals to reduce dependence on fossil-generated electricity, increase the deployment of renewable energy, and reduce its GHG emissions.

Figure 2-2. Project Team



2.3 Overview of Approach

The evaluation of potential renewable energy projects at locations owned by Salt Lake City and DPU was divided into three sequential phases: a Phase I Preliminary Site Scoping Evaluation, a more detailed Phase II Site-Specific Evaluation, and a third phase evaluation where a cross section of six renewable energy projects evaluated in Phase II were selected to undergo a regulatory assessment and economic analysis.

The purpose of the Phase I Preliminary Scoping Evaluation was to conduct a high-level site assessment to identify, evaluate, and rank sites located at Salt Lake City properties and facilities based on the sites' ability to support a renewable energy project and generate power. The evaluation was designed to provide an initial, high-level screening of potential sites and provide DPU with a prioritized list of sites recommended for more detailed evaluation in Phase II.

The purpose of the Phase II assessment was to provide DPU with sufficient detail about siting characteristics, economic feasibility, regulatory pathways, and options for financing renewable energy projects to enable Salt Lake City to develop an implementation plan for project development. The

19 renewable energy projects selected from Phase I were screened through three sequential assessments in Phase II. The first, a detailed on-site assessment, was conducted by Sunrise Engineering (or by Carollo Engineers for the Salt Lake City Water Reclamation Facility). The on-site assessments recognized that even though a site may exhibit favorable generation potential in Phase I, environmental conditions, geological characteristics, interconnection access, and permitting and zoning limitations may preclude development of a renewable energy project at the location. An on-the-ground detailed assessment of 20 criteria was conducted at each site, including generation potential, interconnection and permitting requirements, zoning standards, and sustainability characteristics. Each site assigned a score for each assessment category using a 0 to 5 scale. Scorecard results were tabulated and input into a spreadsheet tool that scored each project on a weighted 100 point scale. These projects were then ranked according to score with 100 representing the best possible score.

Using the ranked results and input from the Consultant Team, the DPU Steering Committee selected a representative cross section of six projects from the 19 ranked projects taking into consideration technology, location, generation capacity, cost effectiveness, and project visibility. Six projects were selected for further evaluation, including a comprehensive evaluation of the regulatory feasibility and economic viability of each project.

Utah Clean Energy completed a regulatory assessment and identified financing options for each project. The regulatory assessment details current statutes, rules, and regulations that have the potential to impact the development, interconnection, and delivery of each renewable energy project evaluated.

Energy Strategies employed an annual cash flow model to evaluate the economic viability of each of the six renewable energy projects relative to a “Business as Usual” (BAU) scenario. The economic model provided an incremental analysis and comparison of both cash flow and GHG emissions savings associated with each proposed renewable energy project compared to the BAU case to establish the cost effectiveness and environmental benefits of each project.

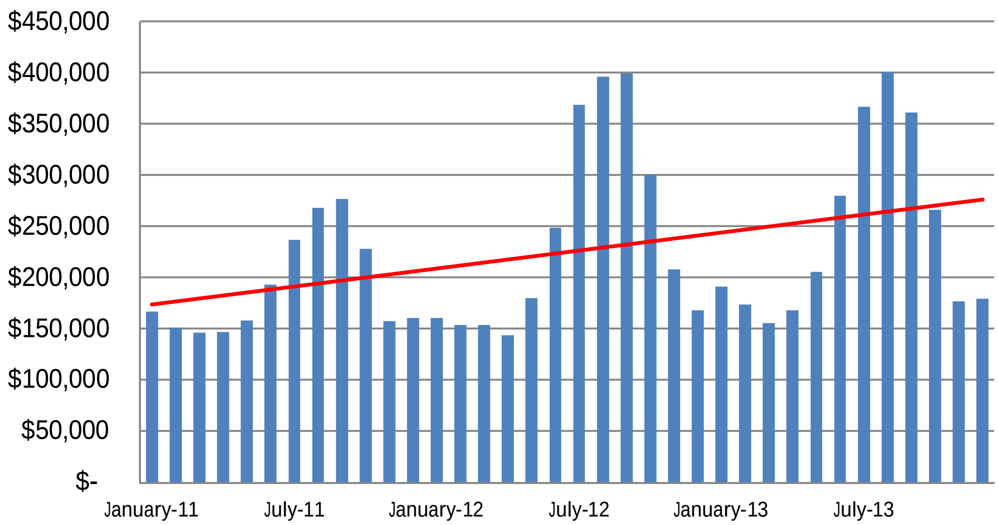
The results of the evaluation process employed by the Consultant Team were intended to provide DPU with sufficient detail on the 19 renewable energy projects evaluated in Phase II to allow for their subsequent development. A detailed description of methodologies for screening of renewable energy projects, detailed evaluations of site characteristics, economics, and regulatory options was provided in this report.

3.0 ENERGY USE PROFILE AND CO_2 EMISSIONS FOOTPRINT

Energy is one of the biggest economic and environmental costs of delivering water to taps and treating wastewater, and DPU is striving to reduce its reliance on coal and fossil fuels as it provides these essential services to its service area.

DPU supplies more than 349,000 customers in Salt Lake City and surrounding areas in Salt Lake County with culinary water, providing an average of 89.8 million gallons of water daily. Delivery of water to Salt Lake City service area residents depends on a complex network of free-flowing streams, reservoirs, aqueducts, water treatment plants, distribution systems, and water mains. DPU also collects and treats wastewater at the Salt Lake City Water Reclamation Facility (SLCWRF), a 56-million gallon wastewater treatment plant. Additionally, DPU manages the street lighting enterprise fund, which is responsible for maintaining and operating more than 15,000 street lights within Salt Lake City. To manage this vast system, DPU uses a significant amount of energy. In 2013, DPU consumed 32,320 MWh of electricity and burned 16,819 decatherms (DTH) of natural gas to operate the systems it manages. Figure 3-1 illustrates DPU's electricity and natural gas expenditures by month.

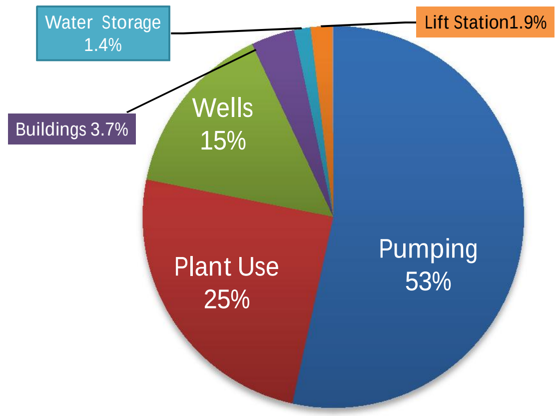
Figure 3-1. Electricity and Natural Gas Expenditures by Month



DPU is served by two electric utilities; Rocky Mountain Power (RMP) provides the vast majority of DPU's electricity, and Murray City Power provides power to a single pump station. The electricity provided by RMP has a significant environmental footprint in terms of water consumed and emissions of criteria pollutants and CO_2. Electric rate structures vary by facility.

In general, the majority of DPU's electricity use is from pumping water and wells to supply water to its customers. About 75 percent of DPU's electricity demand is assigned to wells and pumps, as illustrated in Figure 3-2.

Figure 3-2. Energy Consumed by End Use



3.1 Electricity

DPU has a peak energy demand in the summer months and its energy demand is correlated to its customers' water demand. Unfortunately, DPU's demand for electricity peaks during the summer (when the cost of electricity is higher), and electricity demand is lower in the winter (when the cost of electricity is lower). The monthly and yearly changing electricity demand can be seen in Figure 3-3.

In 2013, DPU spent $2.8 million dollars on electricity alone. DPU pays six different rates for electricity, which are based on RMP rate schedules for different types of facilities. The average price paid by DPU in 2013 was 8.7 cents per kWh, an increase from the average price in 2011 (7.9 cents/kWh) and in 2012 (8.2 cents/kWh). DPU paid approximately 10 percent more for electricity in 2013 than in 2011, as shown in Table 3-1. This change in the average price is based on a number

Figure 3-3. Electricity Consumption by Month 2011-2013

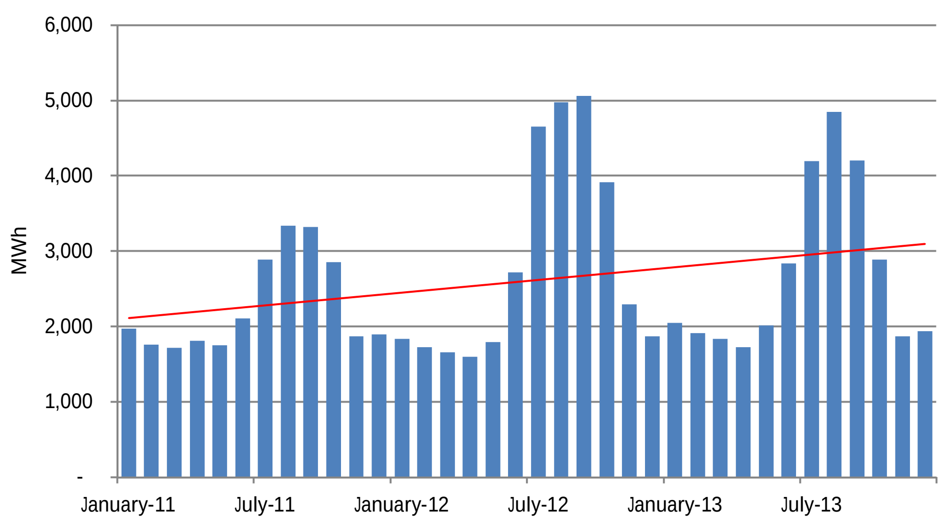


Table 3-1. DPU Electricity Use

Year	MWh	Average $/kWh	Dollars Spent	Emissions Tons CO_2[2]
2011	27,295	$0.079	$ 2,158,849	22,655
2012	34,085	$0.082	$ 2,774,725	28,291
2013	32,320	$0.087	$ 2,805,383	26,826

of factors, including higher RMP electricity rates and more purchases of electricity during summer peak energy times.

The challenge for DPU in future years will be to manage costs given a growing population and increasing electricity costs. For example, in 2011 DPU spent $2.1 million on electricity, however, in 2013 DPU spent $2.8 million on electricity (an increase of $700,000 or, 23 percent, in two years). This increase in energy expenditures can be seen in Figure 3-3, and the upward trend is illustrated by the red trend line.

3.2 Natural Gas

DPU's natural gas use is very different than its electricity use. Unlike electricity demand, DPU's natural gas usage peaks in the winter months to meet heating demand at plants and buildings. Questar Gas Company (Questar) supplies DPU with natural gas, and DPU's demand follows a typical pattern for natural gas with higher peaks in the winter and less demand in the summer.

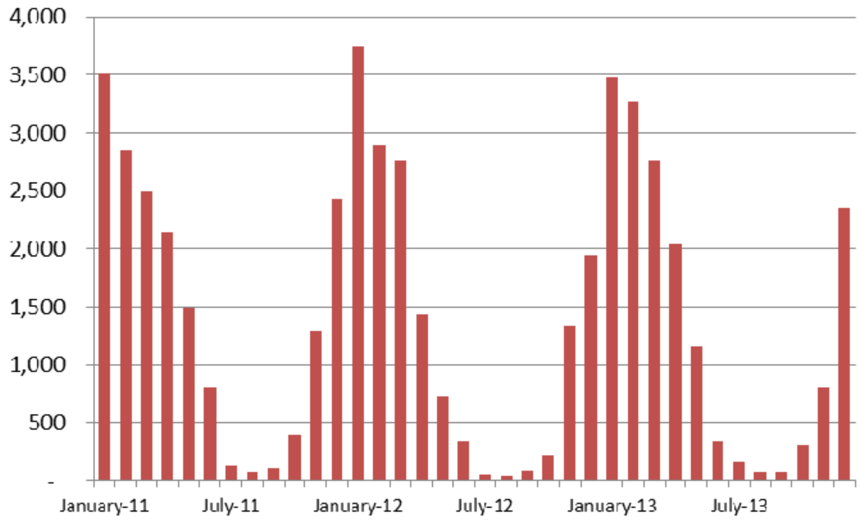
Unlike electricity, DPU's natural gas use and spending has been stable, ranging from $133,661 in 2011 to $123,941 in 2013, as shown in Table 3-2. Figure 3-4 illustrates natural gas consumption by month between 2011 and 2013.

Table 3-2. DPU Natural Gas Use

Year	Decatherm (DTH)	Average $/ DTH	Dollars Spent	Emissions Tons CO_2
2011	17,740	$102	$133,661	1,048
2012	15,609	$83	$110,352	922
2013	16,819	$108	$123,941	994

2 Based on Salt Lake City's assumption that the power provided to them has an emission rate of 1.66lbsCO_2/kWh.

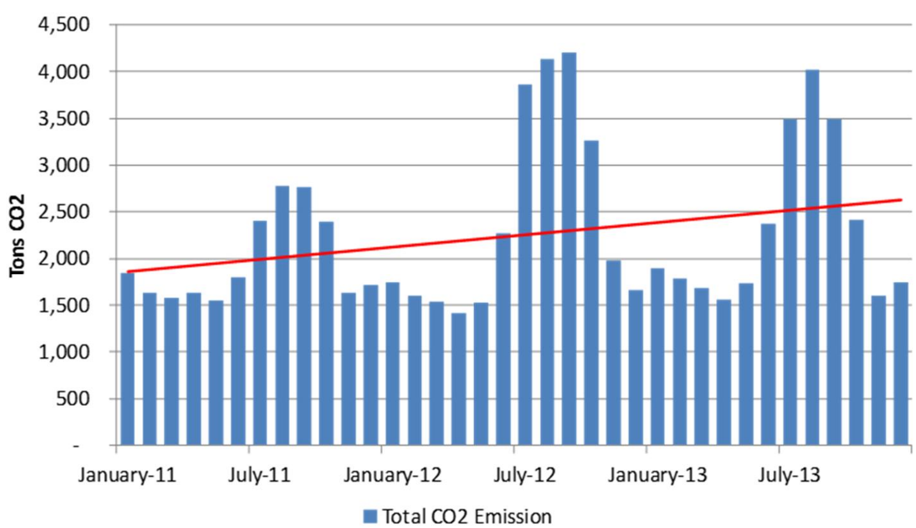
Figure 3-4. Natural Gas Consumption by Month 2011-2013 (DTh)



3.3 DPU Energy Use Carbon Footprint

Salt Lake City estimates there are 1.66 lbs/kWh of CO_2 emissions associated with its electricity use and 13.446 lbs/DTH carbon emission associated with burning natural gas. PacifiCorp, Rocky Mountain Power's parent company, produces 65 percent of its electricity from coal (based on PacifiCorp's 2013 Resource Plan).[3] DPU uses significantly more electricity than natural gas, which means DPU's CO_2 emissions are primarily due to electricity use. In 2013, the CO_2 emissions associated with DPU's consumption of electricity and natural gas totaled 27,820 tons. For the three years data was collected, CO_2 emissions ranged from a low of 23,703 tons in 2011 to a high of 29,213 tons the following year (Figure 3-5).

Figure 3-5. DPU Carbon Footprint from Energy Use 2011-2013



[3] PacifiCorp Integrated Resource Plan, https://www.rockymountainpower.net/about/irp.html.

4.0 PHASE I PRELIMINARY SCOPING EVALUATION

The objective of the Phase I Preliminary Scoping Evaluation was to identify, evaluate, and rank sites located at Salt Lake City properties and facilities which have the potential for renewable energy development. The evaluation was designed to organize 151 sites into a prioritized list based on the evaluation criteria, and then identify those sites which are recommended for evaluation in Phase II.

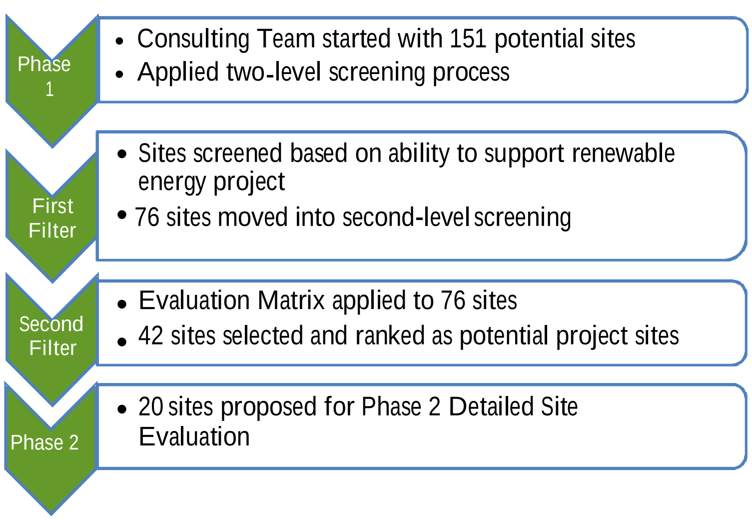
The Phase I evaluation included 50 potential solar photovoltaic (PV) sites (35 water storage facilities, 10 buildings, and 5 open land parcels); 95 potential hydroelectric sites (51 PRV sites, 44 water rights hydropower applications sites, 4 canal drop structures, and 1 pipeline); 2 potential wind power sites; 3 potential wastewater heat recovery sites; and 1 cogeneration site. Several of the water rights hydropower application sites overlapped with PRV sites and the evaluated pipeline sites.

4.1 Assessment Methodology

The 151 sites identified by DPU were put through a two-level screening evaluation. The first level filter assessed the ability of the site to support a renewable energy project and generate power. Sites identified as incapable of supporting a project were immediately eliminated from further consideration (see First Filter in Figure 4.1).

Sites were eliminated if they did not exhibit the necessary physical characteristics to viably support a renewable energy project and generate power. Sites identified as capable of supporting a project were funneled to the second-level filter, a matrix analysis of the project potential based on 6 criteria. Figure 4-1 illustrates the overall process.

Figure 4-1. Phase I Screening Methodology



The purpose of the matrix analysis was to objectively score and rank the remaining sites on a quantitative basis. Projects were ranked in order to select priority project sites which progressed to Phase II of the evaluation.

The matrix employed to conduct the second screening included three site evaluation criteria: annual generation potential, site characteristics, and environmental factors. Annual generation consists of the generation potential at a site. Site characteristics included the potential to offset existing site load, the potential to interconnect and the distance to power distribution infrastructure, and the approximate percentage of DPU load that could be potentially displaced at the site (if available). Environmental factors considered included perceived impact on the surrounding environment and local acceptance of a project. Table 4-1 illustrates the Phase I screening matrix criteria and scoring.

Table 4-1. Phase I Screening Matrix Criteria and Scoring

Category	Weighting Factor	5	4	3	2	1	0
Annual Generation							
Generation (kWh)	5	≥1,000,000	500,000-1,000,000	250,000-500,000	100,000-250,000	<100,000	
Site Characteristics							
Potential to Offset Existing DPU Load	2	Yes					No
Potential to Interconnect	3	Yes		Likely		Maybe	No
Proximity to Load & Distribution Infrastructure	4	≤500 ft	500-1000 ft	1000-1500 ft	1500-2000 ft	2000-2500 ft	2500+ ft
Percentage of DPU Load Displaced	1	81%-100%	61%-80%	41%-60%	21%-40%	1%-20%	<1%
Environmental Factors							
Environmental Impact	5	Negligible	Minor			Moderate	Major
Public Acceptance		100% Positive	90% Positive	80% Positive	70% Positive	60% Positive	50% Positive

Each criterion was given a rating of one through five, five being the highest, and weighted in such a way that if a site were to receive a rating of five for all criteria, it would accumulate a total score of 100 points.

4.2 Solar Photovoltaic Generation

Several types of solar photovoltaic systems were evaluated for this project, including ground-mounted systems of various sizes, small utility-scale systems, and distributed rooftop solar systems. Major factors considered in the design of these systems included shading, solar insolation (the average amount of solar radiation available in a given area and time), location, and mounting considerations. The advantage of the roof-mounted systems is that they require no additional land and can take advantage of existing DPU or City-owned buildings with flat rooftops. Land requirements for PV installations depend on many factors such as tracking technology, efficiency, and capacity factor. Common practice is to state land requirements in terms of acres per MW. Estimates from recent environmental impact studies done for large scale solar PV plants under development in California and Nevada suggest a requirement of between six and nine acres per MW is common.[4]

[4] NREL, "Land-Use Requirements for Solar Power Plants in the United States." http://www.nrel.gov/docs/fy13osti/56290.pdf

Fifty sites were evaluated for solar photovoltaic (PV) power potential. The sites consisted of 35 water storage facilities (reservoirs and tanks), 10 buildings or building complexes, and 5 open land parcels. Due to their proximity, Terminal Reservoir and Park Reservoir were combined as one site, as well as Granite Oaks Tank and Telford Reservoir, leaving 48 sites for evaluation. All of the solar PV sites exhibited the potential to generate electricity, so none of the solar PV sites were eliminated by the level one filter. Table 4-2 provides a summary of the 48 solar PV sites evaluated.

Table 4-2. Solar PV Potential Evaluation Summary

Site Name	Site Type	Capacity (kW)	Average Annual Generation (kWh)	On-Site or Adjacent Loads
Terminal Reservoirs/Park Reservoir	Water Tank/Res. - Roof Mount	1562	2,280,520	Wells 3580 E #4 & #5
Baskin Reservoir	Water Tank/Res. - Roof Mount	395	576,700	Bonneville PS
15th East Reservoir	Water Tank/Res. - Roof Mount	290	423,400	500 S Well & University PS
Military Reservoir	Water Tank/Res. - Roof Mount	256	373,760	Military PS
Victory Road Reservior	Water Tank/Res. - Roof Mount	248	362,080	
Wilson Reservoir	Water Tank/Res. - Roof Mount	241	351,860	Arlington Hills PS
Marcus Reservoir	Water Tank/Res. - Roof Mount	190	277,400	
Morris Reservoir	Water Tank/Res. - Roof Mount	176	256,960	North Bench PS
McEntire Reservoir	Water Tank/Res. - Roof Mount	142	207,320	
13th East Reservoir	Water Tank/Res. - Roof Mount	114	166,440	
Ensign Downs Lower Tank	Water Tank/Res. - Roof Mount	105	153,300	Ensign Downs PS
Tanner Reservoir	Water Tank/Res. - Roof Mount	67	97,820	Dyers Inn Well
Granite Oaks Tank/Telford Reservoir	Water Tank/Res. - Roof Mount	54	78,840	Granite Oaks PS
Tavaci Tank	Water Tank/Res. - Roof Mount	47	68,620	Tavici PS
Capital Hill Tanks	Water Tank/Res. - Roof Mount	45	65,700	
Mt Opympus Tanks	Water Tank/Res. - Roof Mount	45	65,700	Mount Olympus PS
East Bench Tanks	Water Tank/Res. - Roof Mount	38	55,480	Carrigan Cove PS
Ft Douglas Reservoir	Water Tank/Res. - Roof Mount	34	49,640	
Emigrattion Reservoir	Water Tank/Res. - Roof Mount	31	45,260	
White Reservoir	Water Tank/Res. - Roof Mount	30	43,800	
Perry' Hollow Tank	Water Tank/Res. - Roof Mount	28	40,880	
Teton Tanks	Water Tank/Res. - Roof Mount	15	21,900	
Eastwood Tanks	Water Tank/Res. - Roof Mount	14	20,440	Eastwood PS
Carrigan Cove Tank	Water Tank/Res. - Roof Mount	10	14,600	
Ensign Down Upper Tank	Water Tank/Res. - Roof Mount	9	13,140	
Canyon Cover Upper Tank	Water Tank/Res. - Roof Mount	9	13,140	
Canyon Cover Lower Tank	Water Tank/Res. - Roof Mount	9	13,140	
Ferguson Tank	Water Tank/Res. - Roof Mount	9	13,140	
Raineer Tank	Water Tank/Res. - Roof Mount	6	8,760	
North Bench Tank	Water Tank/Res. - Roof Mount	5	7,300	
Neff's Cayon Tank	Water Tank/Res. - Roof Mount	4	5,840	
Olympus Cove Tank	Water Tank/Res. - Roof Mount	2	2,920	
Millcreek Tank	Water Tank/Res. - Roof Mount	2	2,920	Lower Boundary PS
Boeing	Building - Roof Mount	733	1,070,180	Building Load
XPEDX	Building - Roof Mount	456	665,760	Building Load
Highland High School	Building - Roof Mount	333	486,180	Building Load
Roberts Restaurant and Adjacent Building	Building - Roof Mount	267	389,820	Building Load
410 N. Wright Brothers Drive	Building - Roof Mount	228	332,880	Building Load
Salt Lake City Sports Complex	Building - Roof Mount	187	273,020	Building Load
The Leonardo	Building - Roof Mount	91	132,860	Building Load
Sorenson Multicultural and Unity Fitness Center	Building - Roof Mount	58	84,680	Building Load
SLCDPU Buildings	Building - Roof Mount	57	83,220	Building Load
Horizonte Training Center	Building - Roof Mount	13	18,980	Building Load
South Lift	Open Parcel - Ground Mount	299	436,540	South Sewer LS
Smith & Loveless	Open Parcel - Ground Mount	85	124,100	Smith & Loveless and 4000 W Sewer LS
Concord Lift	Open Parcel - Ground Mount	79	115,340	Concord Sewer LS
6200 S. Well	Open Parcel - Ground Mount	63	91,980	6200 S Well & 6200 S Irrigation PS
Greenfield Village	Open Parcel - Ground Mount	51	74,460	Greenfield Village Well

For purposes of estimating capacity and generation it was estimated that 33.5 percent of a rectangular roof, or 30 percent of a circular roof, can be effectively used for installation of PV modules. The estimated capacity and average annual Alternating Current (AC) generation at each of the sites evaluated are summarized in Table 4-2.

Sites that were not adjacent to a DPU load and found to have an average annual generation less than 100,000 kWh were eliminated from further detailed evaluation of site characteristics and environmental factors in the matrix. Nineteen sites were eliminated based on these criteria, leaving 31 sites fully evaluated and ranked.

4.3 Hydroelectric Generation

Three hydroelectric generation technologies were evaluated for potential use at DPU and Salt Lake City sites: a conventional penstock-turbine configuration installed in conjunction with surface water impoundments; reaction turbines installed at Pressure Reducing Valve (PRV) stations used to control pressure in Salt Lake City's culinary water pipeline system; and micro-siphon hydroelectric generation systems that rely on the flow of surface waters in a canal or similar conveyance with a drop structure.

Ninety-five sites were evaluated for hydroelectric potential. The sites consisted of 51 PRVs, 44 water rights hydropower applications sites, four canal drop structures, and one pipeline. Several of the water rights hydropower application sites overlapped PRV sites and the evaluated pipeline site, which brought the total to 95 sites evaluated. Thirty-one of the PRV stations, 40 of the water rights hydropower application sites, and one of the canal drop structures were eliminated after the level one filter was applied. The estimated capacity and average annual generation at each of the 24 remaining sites potentially suitable for installation of hydroelectric technology are summarized in Table 4-3.

Sites that were not adjacent to a DPU load and that were found to have an average annual generation less than 100,000 kWh were eliminated from further detailed evaluation of site characteristics and environmental factors in the matrix. Eleven sites were eliminated based on these criteria, leaving 13 sites fully evaluated in the matrix.

4.4 Wind Power

Wind power is extracted from air flow using wind turbines to produce electric power. Wind power is very consistent from year to year but has significant variation over shorter time scales. As a renewable resource, wind is classified according to wind power classes, which are based on wind speed frequency distributions and air density. These classes range from Class 1 (the lowest) to Class 7 (the highest). In general, at a 50-meter height, wind power Class 4 or higher could be useful for generating wind power with turbines in the range of 250-kW to 750-kW.

Table 4-3. Hydroelectric Potential Evaluation Summary

Site Name	Site Type	Capacity (kW)	Average Annual Generation (kWh)	On-Site or Adjacent Loads
D74-DV1	PRV	359	1,310,352	
B35-R18	PRV	422	1,539,757	
B11-R13	PRV	292	1,064,622	
C41-R20	PRV	281	1,025,114	
B6-R73	PRV	266	970,091	
D69-R40	PRV	63	228,660	
A23-R5	PRV	59	216,797	
C1-R74	PRV	54	196,973	
F78-CR28	PRV	41	151,340	
G35-CR53	PRV	36	131,639	Private Well
E10-R55	PRV	24	88,569	
F60-CR47	PRV	19	70,807	
G38-CR57	PRV	17	62,052	7800 S PS
C12-R15	PRV	16	58,332	
D41-R35	PRV	13	46,610	
B36-R19	PRV	13	46,447	
D69-R39	PRV	11	38,378	
C41-R22	PRV	9	33,786	
F26-CR14	PRV	2	6,834	
F76-CR48	PRV	1	2,546	Dyers Inn Well
Mountain Dell Dam	Surface Water	410	2,370,536	Parley's WTP
Big Spill	Surface Water	15	65,520	On-site pump, lighting and gates
The Tower	Surface Water	8	32,256	On-site gates
2100 S. Plaza	Surface Water	2	8,784	On-site gates

For the evaluation of wind power potential, DPU requested the evaluation of two sites, Mountain Dell Reservoir and the adjacent water treatment plant. For the first level filter the Consultant Team utilized the U.S. Department of Energy and NREL 50-meter height wind resource map for Utah.[5] The map shows Wind Power Density (WPD) estimates at 50 meters (approximately 164 feet) above the ground and identifies wind resources that could be used for community-scale wind development using wind turbines at 50 to 60-meter hub height. The evaluation of the wind resource map indicates that the larger contiguous areas of good-to-excellent resources are located in western Utah, especially near the Raft River Mountains near the Idaho border, and in the area near Milford. Other good–to–excellent wind resource areas are located on the higher ridge crests throughout the state. In the Salt Lake Valley, the best wind resources (Class 2 to Class 4) are located at the mouths of Parley's, Millcreek, Big Cottonwood, and Little Cottonwood Canyons, and along Traverse Ridge.

The evaluation of the wind resource potential at the Mountain Dell Reservoir sites and the adjacent water treatment plant indicate these sites are located in Class 1 (the lowest) zone where the wind speed at the 50-meter height ranges from zero to 12.5 miles per hour. Accordingly, Mountain Dell

[5] Utah 50-Meter Wind Map, U.S. Department of Energy and National Renewable Energy Laboratory http://apps2.eere.energy.gov/wind/windexchange/maps_template.asp?stateab=ut.

Reservoir and the adjacent water treatment plant were not considered to be viable candidates for wind power generation and eliminated from consideration.

4.5 Wastewater Heat Recovery

Municipal wastewater is a promising source of energy which can be harnessed by using the discharge of water through sewer mains as a heat source and retrofitting lines with heat exchangers in conjunction with a larger heat pump. There are two different ways of recovering energy from wastewater: installation of a heat exchanger on the bed of the sewer or an external heat exchanger with an upstream pump and filter installation.

For the evaluation of wastewater heat recovery opportunities, DPU requested the technology be evaluated for its potential application at treated discharge water at the SLCWRF where it could be used for drying sludge. Additionally, the sewer main along 500 South near the Central Heating Plant, and the sewer main along West Temple next to the DPU campus were evaluated to supplement heating load at adjacent buildings.

In the Phase I screening it was determined that utilizing wastewater heat recovery at SLCWRF to increase the efficiency of drying sludge was not likely an economical or operationally feasible application of the technology. A demonstration project at the West Temple trunkline adjacent to the DPU campus was evaluated instead.

4.6 Cogeneration at SLCWRF

Carollo Engineers conducted an assessment of the SLCWRF to identify opportunities to expand or replace cogeneration technology at the site. A preliminary screening of the SLCWRF treatment plant was not undertaken because the site already supported a cogeneration system that used a renewable energy source, biogas, to generate electricity. The project was moved to the Phase II detailed site evaluation for further consideration. During Phase II, the Consultant Team evaluated optimizing the use of the plant’s biogas production with the existing cogeneration system in addition to new generation options.

4.7 Summary of Phase I Evaluation and Site Prioritization

The Phase I evaluation process conducted an initial screening of 151 sites. These included 50 sites for solar PV potential (35 water storage facilities, 10 buildings, and 5 open land parcels); 95 sites for hydroelectric potential (51 PRVs, 44 water rights hydropower applications sites, four canal drop structures and one pipeline); two sites for wind power potential; three sites for wastewater heat recovery potential; and one site for cogeneration potential. This preliminary screening and evaluation identified the technical generation potential of different renewable energy technologies at specific sites owned and operated by DPU. Of the original 151 sites identified, 42 sites were ultimately fully evaluated using the matrix spreadsheet.

The results show that sites with a score of 80 or higher generally had the ability to both generate at a higher capacity and offset either all or a portion of on-site DPU loads. The exceptions were four PRV sites that were not located adjacent to DPU loads but have the potential to generate at a higher capacity than other sites and possibly interconnect at a distribution line. Sites with mid-range scores between 60 and 79 were generally sites that either had a low generation potential but are located adjacent to a DPU load, or generate at a moderate capacity when compared to other sites and must interconnect to a distribution line nearby or potentially a short distance from the site. Sites with a low range score of less than 60 were generally sites with greater environmental impact potential or exhibited site constraints that may render the site more difficult to develop. Table 4-4 illustrates the results of the Phase I scoring. Appendix A provides the complete Phase I evaluation matrix input and results.

Table 4-4. Phase I Evaluation Scores

Ranking	Site Name	Technology	Site Type	Capacity (kW)	Annual Energy (kWh)	Total Points
1	Mountain Dell Dam	Hydroelectric	Surface Water	410	2,370,536	98
2	Terminal Reservoirs/Park Reservoir	Solar PV	Water Tank/Reservoir - Roof Mount	1,562	2,280,520	92
3	Morris Reservoir	Solar PV	Water Tank/Reservoir - Roof Mount	176	256,960	90
4	South Lift	Solar PV	Open Parcel - Ground Mount	299	436,540	90
5	15th East Reservoir	Solar PV	Water Tank/Reservoir - Roof Mount	290	423,400	86
6	Salt Lake City Sports Complex	Solar PV	Buildings - Roof Mount	187	273,020	86
39	Military Reservoir	Solar PV	Water Tank/Reservoir - Roof Mount	256	373,760	86
7	B35-R18	Hydroelectric	PRV	422	1,539,757	85
8	B11-R13	Hydroelectric	PRV	292	1,064,622	85
9	C41-R20	Hydroelectric	PRV	281	1,025,114	85
10	Victory Road Reservior	Solar PV	Water Tank/Reservoir - Roof Mount	248	362,080	85
11	Concord Lift	Solar PV	Open Parcel - Ground Mount	79	115,340	85
12	Baskin Reservoir	Solar PV	Water Tank/Reservoir - Roof Mount	395	576,700	84
13	Wilson Reservoir	Solar PV	Water Tank/Reservoir - Roof Mount	241	351,860	82
16	B6-R73	Hydroelectric	PRV	266	970,091	80
17	East Bench Tanks	Solar PV	Water Tank/Reservoir - Roof Mount	38	55,480	79
18	G35-CR53	Hydroelectric	PRV	36	131,639	78
14	6200 S. Well	Solar PV	Open Parcel - Ground Mount	63	91,980	76
19	Tanner Reservoir	Solar PV	Water Tank/Reservoir - Roof Mount	67	97,820	76
20	Granite Oaks Tank/Telford Reservoir	Solar PV	Water Tank/Reservoir - Roof Mount	54	78,840	76
21	Mt Opympus Tanks	Solar PV	Water Tank/Reservoir - Roof Mount	45	65,700	76
22	Eastwood Tanks	Solar PV	Water Tank/Reservoir - Roof Mount	14	20,440	76
23	Sorenson Multicultural and Unity Fitness Center	Solar PV	Buildings - Roof Mount	58	84,680	76
24	SLCDPU Buildings	Solar PV	Buildings - Roof Mount	57	83,220	76
25	Greenfield Village	Solar PV	Open Parcel - Ground Mount	51	74,460	76
26	Marcus Reservoir	Solar PV	Water Tank/Reservoir - Roof Mount	190	277,400	75
27	Capital Hill Tanks	Solar PV	Water Tank/Reservoir - Roof Mount	45	65,700	75
28	G38-CR57	Hydroelectric	PRV	17	62,052	74
29	D69-R40	Hydroelectric	PRV	63	228,660	70
30	C1-R74	Hydroelectric	PRV	54	196,973	70
31	A23-R5	Hydroelectric	PRV	59	216,797	67
32	Ensign Downs Lower Tank	Solar PV	Water Tank/Reservoir - Roof Mount	105	153,300	67
15	D74-DV1	Hydroelectric	PRV	359	1,310,352	65
33	Big Spill	Hydroelectric	Surface Water	15	65,520	60
34	Smith & Loveless	Solar PV	Open Parcel - Ground Mount	85	124,100	49
35	McEntire Reservoir	Solar PV	Water Tank/Reservoir - Roof Mount	142	207,320	45
36	13th East Reservoir	Solar PV	Water Tank/Reservoir - Roof Mount	114	166,440	45
37	F78-CR28	Hydroelectric	PRV	41	151,340	42
38	Tavaci Tank	Solar PV	Water Tank/Reservoir - Roof Mount	47	68,620	42
39	Salt Lake City Water Reclamation Facility	Cogeneration				
40	Salt Lake City Water Reclamation Facility	WWHR	Treated Wasetwater Effluent			
41	500 South Trunkline	WWHR	Wastewater Conveyance Main			
42	West Temple Trunkline	WWHR	Wastewater Conveyance Main			

As a result of the Phase I screening evaluation, 42 sites were ranked and presented to DPU for review. After consultation with the DPU Steering Committee, 19 sites were selected for more detailed evaluation in Phase II, as shown in Table 4-5.

Table 4-5. Renewable Energy Projects Selected for Phase II Evaluation

Site Name	Technology
Terminal and Park Reservoirs	Roof-mounted Solar PV
Morris Reservoir	Roof-mounted Solar PV
15th East Reservoir	Roof-mounted Solar PV
Victory Road Reservior	Roof-mounted Solar PV
Baskin Reservoir	Roof-mounted Solar PV
Wilson Reservoir	Roof-mounted Solar PV
Sorenson Fitness Center	Roof-mounted Solar PV
DPU Campus	Roof-mounted Solar PV
South Lift Station	Ground-mounted Solar PV
Concord Lift Station	Ground-mounted Solar PV
6200 S. Well	Ground-mounted Solar PV
Greenfield Village Well	Ground-mounted Solar PV
Mountain Dell Dam	Hydroelectric
PRV Station B35-R18	Hydroelectric
PRV Station B11-R13	Hydroelectric
PRV Station C41-R20	Hydroelectric
PRV Station D74-DV1	Hydroelectric
SLCWRF	Biogas Cogeneration
West Temple Trunkline	Wastewater Heat Recovery

5.0 PHASE II SITE-SPECIFIC EVALUATIONS

The Phase I evaluation was designed to filter potential renewable projects into a smaller set of projects that were subjected to a site-specific technical assessment. A total of 19 project sites (12 solar sites, five hydroelectric sites, one wastewater heat recovery site, and one cogeneration site) were evaluated as part of the Phase II Site-Specific Evaluations.

5.1 Overview of Methodology

The Phase II evaluation of the 19 renewable energy project sites was broken down into three sequential assessments. The first, a detailed site assessment, was conducted by Sunrise Engineering, Carollo Engineers, and Utah Clean Energy. The site evaluation was undertaken in recognition of the fact that even though a site may exhibit favorable generation potential in Phase I, structural considerations, environmental conditions, geological characteristics, interconnection access, and permitting and zoning limitations may preclude development of a renewable energy project at the location.

Each site was visited by team members and subjected to a detailed evaluation of its technical capability to support a renewable project. The evaluation criteria and scoring range were developed by the Consultant Team in consultation with the DPU Steering Committee.

The Consultant Team understood DPU was seeking both a quantitative and qualitative evaluation and comparative assessment of renewable energy project sites. A scoring and ranking system was created by the Consultant Team to allow for a consistent and objective ranking and comparative analysis of the diverse range of renewable energy technologies and sites. Assessment of the viability of each renewable energy project was conducted on the basis of six categories covering site compatibility, generation potential, interconnection and permitting requirements, zoning standards, and sustainability characteristics. Each category was scored on the basis of two to six criteria that were assigned a score using a 0 to 5 scale, with five being the highest score. Recognizing that some factors are more important for success than others, the scorecard results were tabulated and input into a spreadsheet tool that assigned a percentage weight to each criteria and each category, and calculated a final weighted score of 0 to 5 for each project. The weighted score for each site was then converted to a 100-point scale. Table 5-1 shows the detailed site evaluation criteria by evaluation category.

5.2 Solar PV

Twelve solar PV sites were selected for the Phase II detailed site evaluation. These project sites are provided in Table 5-2.

5.2.1 Detailed Site Evaluation

Each solar site was evaluated using a four step process: data collection and site analysis, preliminary PV array layout, capacity and generation estimation, and scoring and ranking of projects.

Table 5-1. Detailed Site Evaluation Criteria and Scoring

Evaluation Category	Criteria	Scoring Weight
Site	• Compatibility with the existing site use. • Compatibility with existing infrastructure. • Site access for construction and interconnection activities. • Obvious topographical, geologic, property, environmental constraints. • Potential public safety risk. • Conflicts with established land uses and potential of being a public nuisance.	30%
Interconnection	• Direct access to DPU load or the distribution system. • Complexity and costs of interconnection requirements.	15%
Zoning	• Extent to which the development of a renewable energy project would be compatible with existing zoning ordinances. • Whether those ordinances could potentially be changed if necessary.	15%
Permitting	• Required no. of permits. • Complexity of a permitting process.	10%
Generation	• Quality of the renewable energy resource. • Potential to increase DPU energy system resiliency to power outages and reliability. • Contribute to offsetting electricity load at the site. • Contribute to offsetting DPU's largest and most critical end use loads.	20%
Sustainability	• Contribution to meeting Salt Lake City's renewable energy goals. • Reducing reliance on fossil fuel generated electricity. • Contribute to meeting Salt Lake City's GHG goals. • Whether the project will enhance opportunities to educate Salt Lake City residents and improve public perception of DPU and Salt Lake City's commitment to clean energy and air. • Potential to enhance opportunities for local clean energy vendors and jobs. • Demonstrates leadership in the deployment of distributed renewable energy systems in Salt Lake City and help remove regulatory or policy barriers.	10%

Data collection consisted of a site visit to each of the 12 solar sites. Site assessments included the evaluation of site characteristics including current use of the site, structural design issues, available space, shading obstacles, consideration of potential interconnection options, zoning requirements, ease of permitting, a more detailed evaluation of generation potential strategies, and anecdotal information obtained from speaking with DPU employees.

Radiation data in the Salt Lake City area was also collected and a shading analysis was performed at each site using a Solar Pathfinder instrument, which takes into account the site latitude and how an obstruction may cause shading at a site over a calendar year.

Table 5-2. Solar PV Sites Evaluated in Phase II

Site Name	Site Type	Installation Type
Terminal and Park Reservoirs	Water Tank/Reservoir	Roof Mount
Morris Reservoir	Water Tank/Reservoir	Roof Mount
15th East Reservoir	Water Tank/Reservoir	Roof Mount
Victory Road Reservior	Water Tank/Reservoir	Roof Mount
Baskin Reservoir	Water Tank/Reservoir	Roof Mount
Wilson Reservoir	Water Tank/Reservoir	Roof Mount
Sorenson Fitness Center	Building	Roof Mount
DPU Campus	Building	Roof Mount
South Lift Station	Open Parcel	Ground Mount
Concord Lift Station	Open Parcel	Ground Mount
6200 S. Well	Open Parcel	Ground Mount
Greenfield Village Well	Open Parcel	Ground Mount

The interconnection assessment evaluated whether there was direct access to DPU loads or electrical distribution and the technical feasibility of interconnection. Each of the solar sites evaluated had a nearby or adjacent DPU service load and potential interconnection point to the electrical distribution system. It was also found that each of the potential sites would require either the upgrade or installation of a pad-mount transformer to facilitate a tie-in to the distribution system.

Five of the solar sites would require a zoning ordinance change in order to install solar PV arrays (Baskin Reservoir, Concord Lift Station, Morris Reservoir, Terminal and Park Reservoirs, Victory Road Reservoir), however, it is not anticipated that an ordinance change would result in a lengthy protracted process. The other seven sites are already zoned for solar array installation.

It is anticipated that a conditional use permit would be required for each site and would be relatively simple to obtain for at least 10 of the 12 potential sites. Two of the sites (Concord Lift Station and Wilson Reservoir) may be more difficult to permit due to adjacent property owner access issues (Concord Lift Station) and the potential to impair scenic vistas (Wilson Reservoir).

A preliminary PV array layout was developed to maximize the number of PV modules that may reasonably be installed at each site. Based on the PV array layout, the potential first year of electricity generation for each site was estimated. The accumulative output for 25 years was also estimated using a module degradation rate of 0.6 percent per year. Table 5-3 provides a summary of the capacity and generation estimates at each site.

5.2.2 Scoring and Ranking of Solar PV Projects

Scores for each of the 12 solar sites were developed following the evaluation of each site. Based on the results of the on-site evaluation of siting characteristics, generation potential, ease of interconnection with load and/or the grid, permitting and zoning, and consideration of additional

sustainability, criteria scores for each solar site were tabulated and ranked relative to the other potential solar PV projects. Table 5-4 provides a summary of the scoring and ranking of each site.

Table 5-3. Solar PV Capacity and Generation Estimates

Site Name	Number of Panels	AC Capacity (kW)	Average Annual Generation (kWh)
Terminal & Park Reservoirs	15,853	3,488	4,489,218
Morris Reservoir	1,244	274	360,918
15th East Reservoir	1,244	274	334,918
Victory Road Reservoir	2,029	446	556,634
Baskin Reservoir	1,908	420	514,706
Wilson Reservoir	1,161	255	335,868
Sorensen Fitness Center			
DPU Campus			
South Lift Station	1,312	289	380,608
Concord Lift Station	288	63	75,461
6200 South Well	220	48	49,644
Greenfield Village Well			

Table 5-4. Solar PV Project Scoring and Ranking

Project Site	Technology	Capacity (kW)	Score
Sorenson Fitness Center	Building Rooftop PV	NA	85.6
DPU Campus	Building Rooftop PV	NA	85.4
15th East Reservoir	Roof Mounted PV	274	84.6
South Lift Station	Ground Mounted PV	289	83.3
Wilson Reservoir	Roof Mounted PV	255	71.9
6200 S. Well	Ground Mounted PV	48	68.6
Greenfield Village Well	Ground Mounted PV	NA	67.3
Morris Reservoir	Roof Mounted PV	274	67.2
Victory Road Reservoir	Roof Mounted PV	446	66.3
Terminal & Park Reservoirs	Roof Mounted PV	3,488	65.0
Baskin Reservoir	Roof Mounted PV	420	62.6
Concord Lift	Ground Mounted PV	63	50.6

5.3 Hydroelectric Generation

Five of the 95 hydroelectric sites evaluated in Phase I were selected for a more detailed Phase II evaluation. The selected sites include one conventional hydroelectric site at Mountain Dell Dam just upstream of the Parley's Water Treatment Plant, and four PRV sites located within the water distribution system, as shown in Table 5-5.

Table 5-5. Hydroelectric Sites Evaluated in Phase II

Site Name	Site Type
Mountain Dell Dam	Surface Water
PRV Station B35-R18	Pressure Reducing Valve
PRV Station B11-R13	Pressure Reducing Valve
PRV Station C41-R20	Pressure Reducing Valve
PRV Station D74-DV1	Pressure Reducing Valve

5.3.1 Detailed Site Evaluation

Evaluation of each hydroelectric site was accomplished in three steps: collection and analysis of flow data, capacity and generation estimation, and scoring and ranking of projects.

Data collection consisted of a site visit to each of the five hydroelectric sites. Site assessments included the evaluation of physical site characteristics (site usage, available space), consideration of potential interconnection strategies, and anecdotal information obtained from speaking with DPU employees. Relevant historical flow data was also provided by DPU for each site. The historical flow data was utilized to develop a flow duration curve providing data on the probability of flow magnitudes based on historical data.

The technical feasibility of interconnection was evaluated at each potential hydroelectric site whether there was direct access to DPU loads or to electrical distribution lines. The proximity and ease of interconnection was preliminarily evaluated including the identification of additional infrastructure that may be necessary. Only the Mountain Dell Dam site had an adjacent DPU service load (Parley's Water Treatment Plant). PRV stations B11-R13, B35-R18, and C41-R20 are each located adjacent to a potential interconnection point to the electrical distribution system. While there are high voltage transmission lines located adjacent to D74-DV1 (adjacent to the I-80 and I-215 interchange), there is no nearby access to the three-phase distribution system. Therefore, construction of a three-phase distribution line would be required to develop hydroelectric power at D74-DV1. Each of the potential sites would require installation of a pad-mount transformer to facilitate a tie-in to the distribution system.

Zoning ordinances in the vicinity of the PRV sites currently allow for utility buildings or structures and transmission wire lines, pipes, or poles. Therefore, it is not anticipated that an ordinance change would be required.

It is anticipated that DPU would be required to either file a notice of intent to construct a qualifying conduit hydropower facility (QCHF), or complete the Conduit Exemption process with the Federal Energy Regulatory Commission (FERC) to complete a project at the Mountain Dell Dam site. For the PRV station sites (B11-R13, B35-R18, and D74-DV1) filing a notice of intent to construct a QCHF with FERC would be required.

Based on a more detailed analysis of flow and head conditions at each hydroelectric site, the capacity and average annual generation at each site was estimated and provided in Table 5-6.

Table 5-6. Hydroelectric Capacity and Generation Estimates

Site Name	Capacity (kW)	Average Annual Generation (kWh)
Mountain Dell Dam	260	690,000
PRV Station B35-R18	220	1,145,000
PRV Station B11-R13	190	773,000
PRV Station C41-R20	170	872,000
PRV Station D74-DV1	300	700,000

The most technically feasible hydroelectric development at Mountain Dell Dam site would be a facility installed upstream of the Parley's Water Treatment Plant at the toe of Mountain Dell Dam, which utilizes the flow and head from Mountain Dell Dam only. Based on our assessment of flow data provided for the Little Dell site and our evaluation of the pre-design report prepared by Alpha Engineering and RB&G Engineering, Inc. (2014), the Consultant Team concluded the results of the report were not reasonable or practical. If DPU still wishes to operate a hydroelectric facility utilizing the head and flow from the Little Dell Bypass, a more detailed evaluation of the hydrology conditions is warranted.

Each of the four PRV stations are technically feasible but would require expansion or reconstruction of the existing vaults to accommodate hydroelectric equipment and controls. It would also be necessary to provide measures to ensure uninterrupted flow to the distribution system in the event the hydroelectric equipment is offline.

In the case of PRV stations B11-R13 and D74-DV1, each vault could be expanded or reconstructed with minimal or no disturbance to adjacent traffic conditions. However, both B35-R18 and C41-R20 are located in vaults directly beneath the roadway. While sites D74-DV1, B35-R18, and C41-R20 have flatter topography directly adjacent to the vault, site B11-R13 is located along a slope which could require significant slope stabilization measures during construction of a vault expansion.

If DPU desires to develop the hydroelectric potential at the PRV stations, it is recommended the sites be metered to collect flow data for at least a year to understand how the flow data from the model may vary from what is actually occurring on-site. This would ensure a more accurate sizing of potential turbine and generator equipment.

5.3.2 Scoring and Ranking of Hydroelectric Projects

For each of the five hydroelectric project sites that underwent a detailed, on-site assessment, scoring was completed based on siting characteristics, generation potential, ease of interconnection with load and/or the grid, permitting and zoning, and consideration of additional sustainability criteria. The scores of each hydroelectric site were tabulated and sites ranked relative to the other projects sites. The Mountain Dell Dam site scored the highest primarily due to its generation potential, proximity to existing load, and interconnection access. A summary of the scoring and ranking results is provided in Table 5-7.

Table 5-7. Hydroelectric Project Scoring and Ranking

Project Site Name	Technology	Capacity (kW)	Score
Mountain Dell Dam	Conventional Hydroelectric	260	80.3
B11-R13	Reverse Pump Turbine	190	58.3
D74-DV1	Reverse Pump Turbine	300	55.4
B35-R18	Reverse Pump Turbine	220	53.8
C41-R20	Reverse Pump Turbine	170	53.8

5.4 Wastewater Heat Recovery

Based on the results of the Phase I preliminary evaluation, the West Temple wastewater heat recovery site located adjacent to DPU Campus was determined to be technically feasible and selected for further evaluation in Phase II.

5.4.1 Detailed Site Evaluation

Data collection consisted of a site evaluation of physical site characteristics (site usage, available space), consideration of potential usage strategies, and anecdotal information obtained from speaking with DPU employees. Relevant historical sewer flow and temperature data were also provided by DPU. The historical data was utilized to understand the energy potential associated with the site.

The proposed wastewater heat recovery facility project would utilize a heat exchanger to extract heat from wastewater flowing in the sewer trunkline along West Temple, adjacent to DPU’s administration campus. The main office currently utilizes four forced air gas units to heat the facility. Wastewater heat recovery technology would utilize a portion of the flow from the adjacent sewer

line, recover heat from the water, and then return it to the sewer line. Where the flow line of the sewer line is approximately 15-feet below street level, water would be screened and pumped to a heat exchanger where heat would be transferred to a water/glycol mixture. The water/glycol mixture would then run to a heat pump which would be connected to the existing forced air system. The heat pump would utilize electric energy to boost the heat potential to the range typically required for a forced air heating system.

The peak output from the system would be approximately 737 MBH (737,000 BTU/hour) utilizing a 156-kW heat exchanger with a 60-kW heat pump. Based on the annual heating profile provided by DPU, it appears a wastewater heat recovery system would meet all the heating requirements for DPU's main office from March through October, and meet a percentage of the need during peak winter heating (January—50 percent, February—60 percent, November—70 percent, December—50 percent). The utility service that would be avoided is natural gas, while additional electricity service is required to operate the heat pump.

5.4.2 Scoring of Wastewater Heat Recovery Site

Scoring for this project considered the viability of the site to support wastewater heat recovery technology, potential to offset natural gas, interconnection with existing heating system load, permitting and zoning, and consideration of additional sustainability criteria. The West Temple Project was not scored because it is a demonstration project that will provide an opportunity to demonstrate the viability of this technology, learn about how it could be used throughout Salt Lake City, and serve as an important educational resource.

5.5 SLCWRF Biogas Cogeneration

The Salt Lake City Water Reclamation Facility was selected to be evaluated in Phase II based on the fact that the site already had a cogeneration system using a renewable energy source—biogas—to generate electricity.

Carollo Engineers prepared a technical memorandum which provides details of the site evaluation, analysis of alternative technologies, and generation assessment. The technical memorandum is included as Appendix B.

5.5.1 Detailed Site Evaluation

Currently at the SLCWRF, digester gas is collected and used to fuel a boiler for digester heating needs or cleaned prior to combustion in two 700-kW engine generators to generate electricity to serve on-site load. Electricity generated through the combustion of digester gas offsets a portion of the power that must be purchased from the local energy utility. Any digester gas in excess of what can be used in the engine generators or boiler is destroyed by flare.

The Consultant Team evaluated two options for maximizing the generation of electricity from biogas at SLCWRF: using the existing generators to combust more biogas through operational

changes, or replacing the generators with newer equipment or other technologies. Based on an analysis of current gas productions, as well as digester gas production projections, the following alternatives were developed and evaluated.

- Alternative 1—Use existing cogeneration engines, run one engine with no natural gas supplementation.
- Alternative 2—Use existing cogeneration engines, run two engines with no natural gas supplementation.
- Alternative 3—Use existing cogeneration engines, run two engines with natural gas supplementation.
- Alternative 4—Replace existing engines with a new engine.
- Alternative 5—Replace existing engines with new micro-turbine.
- Alternative 6—Replace existing engines with new fuel cell.

Each of the alternatives was evaluated based on digester gas production from two treatment process configurations, the current wastewater treatment process, and a biological nutrient removal (BNR) process, which may be required by federal water quality standards in the future.

The results of the detailed analysis as well as recommendations are provided in the complete technical memorandum in Appendix B.

5.5.2 Scoring of SLCWRF Cogeneration Site

Scoring the site was based on the of viability of the site to support generation of renewable electricity, potential to offset natural gas consumed, interconnection requirements, permitting and zoning, and consideration of additional sustainability criteria. The project site scored high due to the existence of the biogas-cogeneration system already in operation including the supporting infrastructure. On a 100 point scale, the project's score was 92.9.

5.6 Summary of Phase II Detailed Site Evaluation Scoring and Ranking

Nineteen project sites went through the Phase II detailed site assessment and were scored according to six categories using 20 criteria covering site, generation potential, interconnection and permitting requirements, zoning standards, and sustainability characteristics. Each criterion was assigned a score of 0 to 5. Scores were then tabulated and input into a spreadsheet tool that calculated a weighted average score based on 100-point scale. The higher the score the more likely the Consultant Team considered the project to be successful in meeting DPU's energy and environmental objectives. Table 5-8 includes all 19 projects ranked from highest to lowest based on the score each project site received. Appendix C provides the detailed Phase II scoring and ranking matrix input and results.

Table 5-8. Detailed Site Evaluation Scoring and Ranking

Site Name	Technology	Capacity (kW)	Scores
SLCWRF	Biogas Cogeneration	1,400	92.9
Sorenson Fitness Center	Building Solar PV	-	85.6
DPU Campus	Building Solar PV	-	85.4
15th East Reservoir	Roof-mounted Solar PV	274	84.6
South Lift Station	Ground-mounted Solar PV	289	83.3
West Temple Trunk-line	Wastewater Heat Recovery	NA	NA
Mountain Dell Dam	Hydroelectric	260	80.3
Wilson Reservoir	Roof-mounted Solar PV	255	71.9
6200 South Well	Ground-mounted Solar PV	48	68.6
Greenfield Village Well	Ground-mounted Solar PV	-	67.3
Morris Reservoir	Roof-mounted Solar PV	274	67.2
Victory Road Reservoir	Roof-mounted Solar PV	446	66.3
Terminal & Park Reservoirs	Roof-mounted Solar PV	3,488	65.0
Baskin Reservoir	Roof-mounted Solar PV	420	62.6
PRV Station B11-R13	Hydroelectric	190	58.3
PRV Station D74-DV1	Hydroelectric	300	55.4
PRV Station B35-R18	Hydroelectric	220	53.8
PRV Station C41-R20	Hydroelectric	170	53.8
Concord Lift Station	Ground-mounted Solar PV	63	50.6

The Consultant Team met with the DPU Steering Committee and used the ranked scores and information from the detailed site evaluations as the basis for developing a short list of projects that would undergo additional economic analysis and regulatory assessment. The Steering Committee and Consultant Team then selected a representative cross section of six projects from the 19 ranked projects. These six projects were advanced to a more comprehensive evaluation. The projects selected for additional assessment are listed in Table 5-9.

Table 5-9. Renewable Energy Projects Selected for Economic and Regulatory Analysis

Site Name	Technology	Capacity (kW)	Scores
SLCWRF	Biogas Cogeneration	1,400	92.9
15th East Reservoir	Roof-mounted Solar PV	274	84.6
West Temple Trunkline	Wastewater Heat Recovery	NA	NA
Mountain Dell Dam	Hydroelectric	260	80.3
Terminal & Park Reservoirs	Roof-mounted Solar PV	3,488	65.0
PRV Station B11-R13	Reverse-pump turbine	190	58.3

6.0 REGULATORY ASSESSMENT—RATE SCHEDULE ANALYSIS

The regulatory assessment addressed tariff options for each of the six renewable energy project sites. The purpose was to identify and make recommendations for the most appropriate rate schedule for the site to maximize the economic benefit of the renewable energy project. Four categories and six rate tariffs were evaluated by the Consultant Team; partial requirements tariffs designed to provide supplementary, backup, and maintenance power to customers who obtain any part of their regular electric requirements from self-generation; tariffs provided by RMP as required by the Public Utilities Regulatory Policy Act (PURPA) to promote greater use of domestic energy and renewable energy;[6] a new tariff designed to serve large customers who would like to build renewable energy projects or purchase renewable energy from third parties and deliver the power to their facilities through RMP's distribution system; and net metering tariffs that allow customers with on-site renewable energy facilities to connect to the electrical grid and receive credit for excess electricity that is produced, but not consumed, on-site. Table 6-1 provides a description of the Rate Tariffs Evaluated.

Table 6-1. Rate Tariffs Evaluated

Tariff Schedule	Description
Electric Service Schedule 31	This schedule is for customers who have on-site generation capacity and require backup and maintenance power. Schedule 31 anticipates that customers will be reducing or eliminating usage of utility power the majority of the time and does not provide credits for electricity production in excess of usage, nor does it allow for resale of excess electricity.
Electric Service Schedule 37	Schedule 37 is available to owners of certified small Qualifying Facilities (QFs): either cogeneration facilities with a design capacity of 1-MW or less, or small power production facilities with capacity of 3-MW or less. Prices for the sale of power through this schedule are published, "standard offer" rates. QFs enter into a written power sales contract with RMP based on the published prices.
Electric Service Schedule 38	Schedule 38 is available to owners of certified cogeneration QFs with capacity greater than 1-MW or small power production QFs with capacity greater than 3-MW. Large QFs negotiate pricing and contract terms directly with RMP.
Electric Service Schedule 32	Customers who want to develop their own renewable energy facilities may contract for the delivery of the electricity from their own off-site renewable projects to their facilities through this tariff. Under this tariff the customer must contract for more than 2-MW of electricity delivery and is responsible for paying all interconnection and integration costs to RMP.
Electric Service Schedule 135 – Net Metering	Schedule 135 is intended primarily to allow an on-site renewable energy project to offset part or all of the customer's own electrical requirements. The customer-generator can aggregate its electrical requirements from multiple meters for the purpose of net metering, as long as all meters are located at or adjacent to the same property. Non-residential facilities can be up to 2-MW.

[6] An owner or operator of a generating facility with a maximum net power production capacity of greater than 1-MW (1,000 kW) may obtain QF status by submitting a "self-certification" (no fee), or by applying for and obtaining FERC certification of QF status (fee required).

6.1 Salt Lake Water Reclamation Facility

The SLCWRF was recently switched from Schedule 9 to Schedule 31, which is Partial Requirements General Service for large customers with more than 1-MW of on-site generation. However, if on-site generation were less than 1-MW, the plant would return to Schedule 9 (General Service, High Voltage).[7] Schedule 31 customers are not eligible for net metering.[8]

The purpose underlying the new "Partial Requirements Service" rate schedule is to set rates such that a customer would pay an equivalent amount under Schedule 31 as they would pay under their general service rate schedule (i.e., Schedule 9) if they did not have on-site generation offsetting their bills. Since DPU has the opportunity to alter the cogeneration process at the reclamation facility, DPU should consider the economics of generation alternatives under Schedule 31 compared to Schedule 9. If on-site cogeneration capacity is less than 1-MW, the facility may revert to Schedule 9 and take backup, supplementary, and maintenance power at Schedule 9 rates.

Finally, DPU could increase use of the existing engines and produce more electricity without upgrading equipment by switching to a rate schedule that allows occasional excess generation. DPU should consider the economics of various technologies according to the rate schedules associated with on-site generation capacity greater than or less than 1-MW (under Schedules 31 and 9, respectively). Neither Schedule 31 nor Schedule 9 allows net metering. However, as a facility taking service under Schedule 31, the SLCWRF may sell excess electricity back to the utility at wholesale "avoided costs" rates using either Schedule 37 (if the capacity sold is less than 1-MW) or Schedule 38 (if greater than 1-MW).

6.2 15th East Reservoir

The 15th East Reservoir is currently receiving electricity through Schedule 6A, a "time of use" schedule that rewards facilities that shift the bulk of their electricity usage to off-peak hours with lower electricity rates during those hours. A substantial portion of the electricity usage at the reservoir appears to be during on-peak hours where Salt Lake City is paying the highest rate. Schedule 6A might not currently be providing the most advantageous rates for this facility. A solar installation will provide electricity primarily during on-peak hours, reducing usage at the reservoir during that time, so Schedule 6A will be a more practical rate schedule for this facility if solar PV is installed.

If a solar PV array is designed to meet existing load and installed at the 15th East Reservoir, the site would be a good candidate for RMP's Schedule 135 Net Metering Tariff. However, net metering does not allow a customer to receive credits in excess of their annual usage, so in order to make the solar project a good candidate for net metering, the size of the system needs to be designed based on the average annual electricity usage at this site (rather than the area available for a solar installation at

[7] The applicability of Schedule 31 recently changed from an elective rate schedule for customers with specific attributes, to a mandatory rate schedule for customers with more than 1-MW of on-site generation.
[8] Schedule 135 is available to non-residential Schedules 6, 6A, 6B, 8, 10, 15, and 23, which all take service at distribution voltage.

the site). It would be possible to install a larger solar array at the site, however electricity generation from the solar PV would exceed the on-site electricity load, and DPU could not receive net metering credits for electricity generated in excess of the annual usage.

Given that the technical potential for solar generation at this site greatly exceeds on-site electricity usage, DPU could choose to construct a larger solar installation than is necessary to meet electricity needs on-site and instead contract to sell the excess electricity in one of two ways. First, this site could be developed to deliver electricity directly to DPU as one project in a portfolio of DPU-owned renewable projects through the contracting provisions allowed under Electric Service Schedule 32. This tariff was enabled by Senate Bill 12 (SB 12) in 2012 (codified at Utah Code Ann. Section 54-17-801, et seq.). Although customers utilizing Schedule 32 must contract to take more than 2-MW of electricity, the law permits multiple renewable energy facilities with 2-MW of aggregated capacity to deliver electricity to a single contract customer. While the cogeneration facility is technically eligible for Schedule 32, this rate schedule will likely only be advantageous for waste heat projects due to the method by which the charge for demand is calculated.

A solar installation at the 15th East Reservoir could certify as a QF and contract to sell electricity to RMP under Electric Service Schedule 37's "avoided cost" rates. Pricing under Schedule 37 was recently litigated and the newly approved published rates are available up to 25-MW of project capacity until next year, when RMP must update pricing again.

6.3 Mountain Dell Reservoir

The Parley's Canyon Water Treatment Plant is currently receiving electricity through Schedule 6A, a "time of use" schedule that rewards facilities that shift the bulk of their electricity usage to off-peak hours with lower electricity rates during those hours. Electricity usage at Parley's Water Treatment Plant appears to be fairly evenly split between on-peak hours and off-peak hours, and so rate Schedule 6A might not currently be providing the most advantageous rates for this facility if a renewable energy project is not developed on-site.

If the hydroelectric project is developed this site is a good candidate for net metering on Schedule 135. A 260-kW hydroelectric turbine falls under the 2-MW capacity limit allowed through Schedule 135. The hydroelectric turbine would produce more electricity in the summer months: an average of 442 MWh annually during the summer season and 247 MWh annually during the winter season. This seasonality is advantageous for a net-metered facility. Credits for excess generation roll over from month to month and can be used to offset future electricity bills, however, all credits for excess generation are forfeited at the end of the annualized billing period, on March 31st.

6.4 Terminal and Park Reservoirs

There is minimal on-site load at this facility compared to the technical potential of the site, so net metering is not a practical option for this site. A solar facility built to take advantage of the available space could produce a substantial amount of electricity. There are four options available for a solar

facility at the Terminal and Park Reservoirs, two of which are immediately available. A third option, Schedule 32, will be available as soon as the proposed tariff is finalized by the Public Service Commission.

Electric Service Schedule 32 is designed to serve large customers, like DPU, who would like to source a larger portion of their electric service from renewable energy resources than is currently available through RMP. Using Schedule 32, large customers will be able to build or purchase energy from off-site renewable energy projects and pay RMP for the delivery of such electricity to their facilities. Thus, DPU could build a solar facility at Terminal and Park Reservoirs and contract for the delivery of electricity from the Reservoirs to another facility through this tariff. Although solar facilities are technically eligible for Schedule 32, this rate schedule may not be advantageous for solar projects due to the method by which the charge for demand is calculated.

Using Schedule 37, DPU could certify the Terminal and Park Reservoirs as a QF and contract to sell electricity to RMP using "avoided cost" rates available to renewable QFs sized 3-MW and smaller.[9] Since Schedule 37 is only available to small projects (3-MW and under), DPU has a couple of options for this site:

- Certify this facility as a QF, build a 3-MW project, and sell the electricity to the utility under Schedule 37.
- Have two separate project owners develop QF projects, each smaller than 3-MW, in order to take advantage of the full technical potential at the site. A single QF project owner may not build more than one project (of the same technology) within a single mile radius; however, Salt Lake City could work with the Metropolitan Water District of Salt Lake and Sandy (MWDSLS) (the owner of two of the water tanks comprising the facility) to develop two separate QF projects at the Terminal and Park Reservoirs, owned by Salt Lake City and MWDSLS respectively. Both facilities could use the same interconnection point, and it may be possible to operate both QFs as a single facility.

Pricing under Schedule 37 was recently litigated and the newly approved published rates are available to 25-MW of project capacity until next year, when RMP must update pricing again. This option is available now and current prices are provided in Table 6-2.

Table 6-2. Schedule 37 Levelized Prices (Nominal) for Solar PV (Cents per kWh)

	On-Peak Energy Prices		Off-Peak Energy Prices	
	Winter	Summer	Winter	Summer
Fixed Tilt Solar PV	4.013	4.246	3.548	3.781
Tracking Solar PV	4.188	4.420	3.613	3.846

[9] For more information about QFs, how to become certified as a QF, and Schedule 37 See Appendix D, "Schedule 37."

Through Schedule 38, the Terminal and Park Reservoirs could certify as a QF and contract to sell electricity to RMP using "avoided cost" rates, available to renewable QFs larger than 3-MW.[10] Unlike Schedule 37, pricing under this schedule is not published; rather, the Commission approved a pricing calculation method that RMP uses to establish "indicative prices" upon request. Pricing and contract terms are then negotiated directly with RMP. Because negotiating pricing with RMP can be a costly and time consuming process, this option, though available to facilities as small as 3-MW, may not be economically feasible for a project smaller than 20-MW. This tariff will be undergoing pricing and process revisions in the coming months.

6.5 PRV Station B11-R13

A 190-kW hydroelectric turbine is proposed to generate electricity using pressure head at an existing PRV in a vault structure. There is no on-site load at this location, so there are a few potential options for using the energy produced at this facility, of which only one is immediately available.

A hydroelectric turbine at this site could certify as a QF and contract to sell electricity to RMP under Electric Service Schedule 37 "avoided cost" rates, available to renewable QFs 3-MW and smaller.[11] Pricing under Schedule 37 was recently litigated and the newly approved published rates are available up to 25-MW of project capacity until next year when RMP must update pricing again. This option is available now and current prices are provided in Table 6-3.

Table 6-3. Schedule 37 Levelized Prices (Nominal) for Baseload Renewable Energy (Cents per kWh)

	On-Peak Energy Prices		Off-Peak Energy Prices	
	Winter	Summer	Winter	Summer
Baseload Renewable Energy	4.589	4.819	3.859	4.089

This site could potentially sell electricity through the contracting provisions enabled under Electric Service Schedule 32. Although customers utilizing Schedule 32 must contract to take more than 2-MW of electricity delivery through Schedule 32, the law permits multiple renewable energy facilities to deliver electricity to a single contract customer. Thus, this site could be one of a portfolio of facilities serving DPU load under Schedule 32.

[10] For more information about QFs, how to become certified as a QF, and Schedule 38 See Appendix D, "Schedule 38."
[11] For more information about QFs, how to become certified as a QF, and Schedule 37 See Appendix D, "Schedule 37."

7.0 ECONOMIC ANALYSIS OF RENEWABLE ENERGY PROJECTS

The DPU Steering Committee and the Consultant Team identified project opportunities at six sites for further economic and regulatory assessment. This section describes the approach, assumptions and results of the economic analysis for each project.

The economic analysis is performed using an annual cash flow model developed by Energy Strategies. The model looks at the economic viability of each project by quantifying the net present value (NPV) of the cost of utility service. The cost of utility service measures the cash flow throughout the life of the project, compared to a business-as-usual (BAU) case where DPU continues to receive utility service from either RMP or Questar. If the NPV is negative then the project is economical, i.e., the costs producing electricity or savings of natural gas due to the renewable energy project is less than utility service over the life of the project.

The model also estimates the levelized cost of power and avoided GHG emissions for each project compared to utility service from RMP and Questar. The economic model also accounts for increases and decreases in the following measures versus the relevant business as usual scenario:

- On-site generating capacity, kW
- Overnight capital, 2014$ millions
- Average annual generation, MWh
- Non-fuel operating expense, 2014$ millions
- As modeled assuming $0 per MTCO$_2$e compliance cost
- Sensitivity analysis at $25 and $50 per MTCO$_2$e compliance cost

A single power generation technology was evaluated for each of four sites proposed for renewable energy development: 15th East Reservoir, B11-R13, Mountain Dell Dam, and Terminal and Park Reservoirs. Four new power generation technologies were evaluated for the fifth site, the SLCWRF. An economic analysis was also conducted for the 1530 South West Temple wastewater heat recovery project but it was based on natural gas saved.

The dollar value assigned to generation is a key assumption. For all but two options, it is assumed that generation would offset purchases of power from RMP and the value of the generation is based on current prices in the electric service schedule that applies to each site.

In the cases of the PRV station B11-R13 and Terminal and Park Reservoirs, generated power exceeds site requirements and is assumed to be sold back to RMP under the Schedule 37 rate. In addition, a sensitivity analysis was conducted on these two sites to evaluate the economic feasibility of those projects if DPU were able to receive credit for excess generation and use it to offset DPU electricity bills at other locations.

7.1 SLCWRF Biogas Cogeneration Site

The SLCWRF biogas cogeneration site is located at Redwood Road and approximately 2000 North in Salt Lake City. Cogeneration already exists at the SLCWRF, where biogas is burned to run two 700-kW engines. The Phase II detailed site evaluation found that the cogeneration system is operating at 48 percent of its nameplate capacity, and generates an average of 5,230 MWh per year to meet the SLCWRF's annual load of 10,858 MWh. In practice, the SLCWRF is running a single engine and consuming 68 percent of the 97,637 MMBtu of biogas produced at the treatment plant each year. The remaining biogas is either consumed as boiler fuel or flared. Five cogeneration options were evaluated for the SLCWRF. Cogeneration capacity estimates varied from 666-kW to 1400-kW for the alternatives evaluated.

Two of the alternatives used operational changes to maximize the use of the two existing 700-kW reciprocating engines. The first alternative evaluated running the engines at a capacity factor high enough to utilize all the biogas produced at the treatment plant. The second alternative assumed the engines were run at their maximum operating capacity which would require the biogas be supplemented with natural gas. The other three options evaluated included replacing the existing engines with a new 1,426-kW reciprocating engine, a 1,000-kW micro-turbine, or 1,400-kW fuel cells. Each of the five power generation technologies considered were also evaluated under two wastewater treatment process scenarios: 1) current process (primary clarification, trickling filters, aeration basins, secondary clarifiers, and solids digestion); and 2) biological nutrient removal process.

To the extent cogeneration at the SLCWRF is currently being limited to one engine, there appears to be an economic opportunity to lower the cost of electricity service supplied to the plant by operating both existing engines using biogas and natural gas as fuels.

If the two existing 700-kW engines are run utilizing only the biogas produced by the treatment plant, DPU would reduce NPV of utility service by $1.458 million over the 20-year life of the project, compared to continuing to receive the same level of service from RMP. If a cost of carbon of $25/MTCO$_2$e or $50/MTCO$_2$e is assumed in the cash flow analysis, then NPV of the economic benefits of the project increase to $2.0 million and $2.5 million respectively.

Running both engines at the capacity factor they are designed to operate at would require utilizing all of the biogas produced at the plant and additional purchase of supplemental natural gas service from Questar. Still, even under this scenario, operating the cogeneration engines to supply electricity to the site proved to be more economical compared to purchasing the equivalent amount of power from RMP. Doing so would reduce NPV of electricity service to the SLCWRF by $243,000 over the 20-year life of the project. If a cost of carbon of $25/MTCO$_2$e or $50/MTCO$_2$e is assumed in RMP's electricity rates, then NPV of the economic benefits of the project increases to $697,000 and $1.12 million respectively.

Table 7-1. Technologies Evaluated For Salt Lake City Water Reclamation Facility

Project Site	Type of Power Technology	Effective Generation Capacity	RMP Electricity Service Schedule	Total Fuel Consumed	Digester Gas Available	Natural Gas Consumed	Average Annual Generation
		kW		MMBTU	MMBTU		MWh
Salt Lake City Water Reclamation Facility	Existing Recip (Run 1)	1,320	RMP 31 (9)	66,151	97,637	-	
	Existing Recip (Run 2 no NG)	1,320		97,128		-	2,553
	Existing Recip (Run 2 with NG)	1,320		111,818		14,181	3,642
	New Recip	1,390		88,333		-	3,855
	Microturbine	844		77,457		-	1,124
	Fuel Cell	1,330		94,582		599	5,187
Salt Lake City Water Reclamation Facility Biological Nutrient Removal	Existing Recip (Run 1)	1,320	RMP 31 (9)	61,651	59,672	1,979	
	Existing Recip (Run 2 with NG)	1,320		111,818		52,146	4,130
	New Recip	827		58,111		289	671
	Microturbine	562		60,816		1,562	-506
	Fuel Cell	855		71,555		11,883	1,964

Moreover, both approaches would result in a meaningful reduction of GHG emissions compared to the current operations where one engine is operated. In the case where both engines are operated based on the available biogas supply from the plant, GHG emissions will be reduced by 1,558 tons, or about 6 percent of DPU's estimated CO_2 emissions emitted from the consumption of electricity and natural gas. Burning all available biogas plus supplemental natural gas to maximize output of the cogeneration engines will also reduce net GHG emissions compared to the reference case by 1,223 tons.

Replacing the existing engines with new reciprocating engines, micro-turbines, and fuel cells was also evaluated. All scenarios where the existing engines were replaced with new cogeneration technology entail significant incremental investment of capital (between $5 and $12 million), making replacement of the existing engines uneconomical. Even when a value of $50 per $MTCO_2e$ is attributed to GHG emissions, replacing the existing engines with newer generation technology is not justified if lowering the cost of electricity service at the SLCWRF is the objective.

The economic analysis described above assumed that SLCWRF would continue to treat effluent using the current process (primary clarification, trickling filters, aeration basins, secondary clarifiers, and solids digestion). If the SLCWRF is required to implement a biological nutrient removal process, this will significantly lower the amount of biogas produced and negatively impact the economic value of all cogeneration opportunities at the SLCWRF. However, the SLCWRF can continue to

operate the existing biogas cogeneration engines, and maximize their use through operational changes, until required to switch to a biological nutrient removal process.

Table 7-2. Salt Lake City Water Reclamation Facility NPV of the Cost of Utility Service

Project Site	Type of Power Technology	Overnight Capital	Non-Fuel Operating Expense	Cost of Utility Service Present Value $Millions			Levelized Cost
		2014$ Millions	2014$ Millions	$0 per MTCO2e	$25 per MTCO2e	$50 per MTCO2e	$ per MWh
Salt Lake City Wastewater Reclamation Facility	Existing Recip (Run 2 No NG)	$0.00	$76.58	($1.46)	($1.996)	($2.533)	$26.50
	Existing Recip (Run 2 with NG)	$0.00	$109.27	($0.27)	($0.697)	($1.120)	$35.50
	New Recip	$9.36	$25.06	$5.94	$5.092	$4.240	$80.00
	Microturbine	$6.73	$65.36	$6.42	$6.169	$5.920	$95.00
	Fuel Cell	$12.09	$328.18	$12.31	$11.181	$10.046	$111.00
	Biological Nutrient Removal						
	Existing Recip (Run 2 with NG)	$0.00	$123.91	$3.11	$3.468	$3.824	$61.50
	New Recip	$8.58	($33.73)	$6.99	$6.785	$6.581	$113.50
	Microturbine	$5.30	$5.88	$5.63	$5.713	$5.795	$108.50
	Fuel Cell	$10.67	$192.50	$12.49	$12.222	$11.953	$149.50

7.2 15th East Reservoir Solar PV Site

The 15th East Reservoir Solar PV site is located at a partially buried concrete reservoir directly east of Rice Eccles Stadium along 500 South in Salt Lake City. The site scored high on the detailed site evaluation and was considered a good candidate site for a future solar PV energy project. The development site would be located on an existing concrete reservoir with open roof space that could support a 274-kW solar PV installation. The majority of the large roof space is relatively new and unobstructed by objects that would create shading impacts. The reservoir is currently surrounded by adequate security fencing, and for the most part is not visible to public at the ground level. The location also has direct access just east of the site to three-phase electrical distribution. There is also on-site access to a DPU load at the University Pump Station and 500 South Well.

A 274-kW solar installation was evaluated at the 15th East Reservoir. A system this size could produce an average of 335,000 kWh of electricity each year. However, electricity meters located at this site report that the on-site load is only 70,000 kWh of electricity each year. This site could support almost five times more solar than is necessary to meet the electricity needs of the on-site facilities. A smaller 25-kW installation at this site could net meter and offset on-site electricity usage however this option was not evaluated. The larger installation would produce more electricity than could be used on-site, and DPU would have to contract to sell the electricity in order to see a financial benefit.

The economic analysis conducted for the 15th East Reservoir site assumed the maximum number of solar panels the site could support would be installed on the roof of the reservoir. The upfront capital costs of the 274-kW solar PV system was estimated to be $920,000, and NPV of operation and maintenance at the site was estimated to be $13,000 per year. Assuming the value of the PV generation at the site would be based on the Schedule 6A rate, NPV of the power generated by the solar array is estimated to exceed the value of electricity supplied by RMP by $426,000 over the 30-year life of the project. Even when a price of carbon of $50/MTCO$_2$e is assumed in the analysis, the project still has an NPV of $200,000 more than service provided by RMP.

However, a smaller, net-metered installation designed to offset on-site electrical usage was not run through the economic analysis. It would likely have a better NPV than the 274-kW project that was evaluated. A lease or a PPA, which was not considered in this evaluation, would allow DPU to take advantage of a federal tax incentive through a third-party ownership structure and could result in a cost reduction of up to 30 percent of. If DPU were to utilize a lease or a PPA, consider optimizing the size of the project based on on-site load, and take advantage of the falling cost of solar, it is likely that this project would offer a better NPV than the cost of utility service over the life of the project.

Table 7-3. 15th East Reservoir NPV of the Cost of Utility Service[12]

Project Site	Type of Power Technology	Use of Generation	Overnight Capital	Non-Fuel Operating Expense	Cost of Utility Service Present Value $Millions			Levelized Cost
			2014$ Millions	2014$ Millions	$0 per MTCO2e	$25 per MTCO2e	$50 per MTCO2e	$ per MWh
15th East Reservoir	Solar PV	Net Metered	$0.920	$0.013	$0.426	$0.314	$0.202	$153.50

7.3 Mountain Dell Dam Hydroelectric Site

The Mountain Dell Dam Hydroelectric site is located at the Parley's Water Treatment Plant along I-80 in Parley's Canyon. A hydroelectric facility would likely be located at the downstream toe of Mountain Dell Dam just upstream of the water treatment facility. The Mountain Dell Dam site was selected by the DPU Steering Committee and Consultant Team for further economic analysis and electric rate assessment because of the following favorable project site characteristics:

1. Sufficient flow to support year-round generation of power.
2. Presence of an existing dam with a water source that employs an energy dissipation valve to burn energy just upstream of the water treatment plant.
3. Available space to develop a facility with the removal of an existing concrete structure (sand separator) and modifications to existing piping.
4. Direct access on-site to water treatment plant facility electrical load and three phase electrical distribution.

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12 Costs and NPV are for a turnkey project without using a PPA or other incentives.

5. Simplified FERC permitting process as power would be a secondary beneficial use of the water, the conduit is owned by Salt Lake City, and the generation capacity is less than 5-MW.

Based on a review of the site and previously performed hydroelectric analyses at Mountain Dell Dam, the Consultant Team concluded there is sufficient space to develop a project at the toe of the dam just upstream of the water treatment plant. The hydroelectric plant would be operated by utilizing water from the Little Dell Reservoir through a 42-inch diameter bypass line 24 hours a day, 365 days a year. The hydroelectric facility would likely utilize a Crossflow-type turbine with an installed capacity of 260-kW and an average annual generation of 690,000 kWh. On-site load at Parley's Treatment Plant is approximately 900 MWh annually, so the electricity produced by a hydroelectric turbine at this location could be used to offset roughly three quarters of electricity used at this site.

Parley's Water Treatment Plant is currently receiving electricity through Schedule 6A. The economic analysis conducted for the Mountain Dell Dam site assumed a 260-kW turbine is installed and generates an annual average 690,000 kWh that is used to offset 75 percent of the load at the Parley's Treatment Plant. Accordingly, the value of the generation from the hydroelectric project was assumed to be the average retail rate for Schedule 6A, which is $11.2772 cents per kWh.
The upfront capital costs of the turbine and power system is estimated to be $1.6 million and the annual average non-fuel operating expenses are estimated to be $19,000 per year. Assuming the value of the generation at the site is based on the Schedule 6A rate, NPV of the power generated by the hydroelectric project is estimated to exceed the value of electricity supplied by RMP by $355,000 over the 50-year life of the project. However, when a price of $50/MTCO$_2$e is assumed in the cash flow analysis, the project's NPV is $228,000 less than service provided by RMP, and this site is considered to be economically viable option for a renewable energy project.

Table 7-4. Mountain Dell Dam Hydroelectric NPV of the Cost of Utility Service

Project Site	Type of Power Technology	Use of Generation	Overnight Capital	Non-Fuel Operating Expense	Cost of Utility Service Present Value $Millions			Levelized Cost
			2014$ Millions	2014$ Millions	$0 per MTCO2e	$25 per MTCO2e	$50 per MTCO2e	$ per MWh
Mountain Dell Dam	Hydroelectric	Net Metered	$1.551	$0.019	$0.355	$0.064	($0.228)	$92.00

7.4 Terminal and Park Reservoirs Solar PV Site

The Terminal and Park Reservoirs solar PV site is located directly west of I-215 at 3300 South in Salt Lake County.

The Terminal and Park Reservoirs site consists of four buried reservoirs (Terminal South, Terminal North, Sam Park, and Sam Park West) with open roof space that could be made available for installation of ground-mounted solar PV panels. The location provides a site that is unobstructed by

objects that would create shading impacts, security fencing, and direct access just south and west to a three-phase electrical distribution system.

A solar PV facility at the Terminal and Park Reservoirs site would likely utilize fixed tilt 275-W PV modules with an installed capacity of 3.5-MW AC and an average annual generation of 4,490,000 kWh.

A 3.5-MW solar PV installation was evaluated for Terminal and Park Reservoirs. The upfront capital costs of the system were estimated to be $11.3 million, and the annual non-fuel operating expense estimated at $13,000 per year. There is virtually no on-site load at this facility compared to the technical potential of the site, so net metering is not a practical option for this site. There are four options available for distributing the excess generation from a solar facility at the Terminal and Park Reservoirs, three of which are immediately available: Tariff Schedules 32, 37, and 38.

Assuming the value of the PV generation at the site would be based on the Schedule 37, NPV of the power generated by the solar array is estimated to exceed the value of electricity supplied by RMP by $10.2 million over the 30-year life of the project. Even when a price of carbon of $50/MTCO_2e$ is assumed in analysis the project still has an NPV of $7.2 million more than service provided by RMP.

Because Schedule 32 had not been finalized by the Public Service Commission at the time of the economic analysis, the economic viability of this tariff option was not evaluated. Although solar facilities are technically eligible for Schedule 32, this rate schedule may not be advantageous for solar projects due to the method by which the demand is calculated. However, this analysis did estimate NPV of the cost of utility service if an alternative net metering tariff were available to DPU and the electricity generated from the PRV Station B11-R13 could be credited to offset DPU loads at other locations. For purposes of this analysis it was assumed the applicable tariff is Schedule 6A.

The only circumstance where the Terminal and Park Reservoirs site would provide lower cost electricity service compared to RMP is by assuming an alternative net metering tariff is available to DPU at the equivalent of the average retail rate for Schedule 6A (i.e., 11.2772 cents per kWh), and including a $50/MTCO_2e$ in the cash flow analysis. Under this scenario, NPV of utility service of this project is $559,000 less than service provided by RMP.

This analysis did not include an assessment of leases or PPAs. Either of these financing structures would allow DPU to take advantage of a 30 percent federal tax incentive through a third-party ownership. Furthermore, the cost of solar has fallen significantly since this report was commissioned. If DPU were to utilize a lease or a PPA, take advantage of the falling cost of solar, and/or apply to receive an incentive through the Utah Solar Incentive Program, this project might offer a better NPV than the existing cost of utility service.

Table 7-5. Terminal and Park Reservoirs NPV of the Cost of Utility Service

Project Site	Type of Power Technology	Use of Generation	Overnight Capital	Non-Fuel Operating Expense	Cost of Utility Service Present Value $Millions			Levelized Cost
			2014$ Millions	2014$ Millions	$0 per MTCO2e	$25 per MTCO2e	$50 per MTCO2e	$ per MWh
Terminal Park Reservoir	Solar PV	Schedule 37	$11.292	$0.150	$10.155	$8.699	$7.242	$139.50
	Solar PV	Net Metered			$2.354	$0.898	($0.559)	$139.50

7.5 PRV Station B11-R13 Hydroelectric Site

The PRV station B11-R13 hydroelectric site is located at the intersection of 1000 East 500 South in Salt Lake City. An existing vault containing two PRV valves is located on-site. A hydroelectric facility would likely be located at the same location or adjacent to the existing PRV vault.

A 190-kW hydroelectric turbine is proposed to generate electricity using pressure head at an existing PRV in a vault structure. A hydroelectric facility at the B11-R13 PRV would likely utilize a reverse pump-type turbine with an installed capacity of 190-kW and an average annual generation of 773,000 kWh.

The upfront capital costs of this renewable energy system are estimated to be $1 million and the annual non-fuel operating expense at the site is estimated to be $13,000 per year. Interior lighting for the vault is the extent of the on-site load, so net metering is not a practical option for this site. There are only two options available for distributing the generation from the B11-R13 PRV vault, Tariff Schedules 32 and 37.

Assuming the value of the electricity produced at the site would be based on the Schedule 37, NPV of the power generated by this micro-hydroelectric project is estimated to exceed the value of electricity supplied by RMP by $585,000 over the 50-year life of the project. However, when a price of $50/MTCO$_2$e is incorporated into the cash flow analysis, the project is economic. Under this scenario, NPV of the cost of utility service is $68,000 less than service provided by RMP.

Because Schedule 32 had not been finalized by the Public Service Commission at the time of the economic analysis, the economic viability of this tariff option was not evaluated. However, this analysis did estimate the NPV of the cost of utility service if an alternative net metering tariff were available to DPU. Alternative net metering tariffs could allow parties who own renewable generation facilities at one location to receive credit for that generation at another. Under such a tariff, the facility does not have to be adjacent to the renewable energy project. In this scenario, electricity generated from the B11-R13 PRV station could be credited to offset DPU loads at other locations. For purposes of this analysis it was assumed the value of electricity that would be offset by the PRV station micro-hydroelectric project would be equivalent to the published Schedule 6A rate.

Table 7-6. PRV Station B11-R13 Hydroelectric NPV of the Cost of Utility Service

Project Site	Type of Power Technology	Use of Generation	Overnight Capital	Non-Fuel Operating Expense	Cost of Utility Service Present Value $Millions			Levelized Cost
			2014$ Millions	2014$ Millions	$0 per MTCO2e	$25 per MTCO2e	$50 per MTCO2e	$ per MWh
PRV Station B11-R13	Micro-Hydro	Schedule 37	$0.999	$0.015	$0.585	$0.258	($0.068)	$55.50
		Virtual Net Metering			($0.188)	($0.515)	($0.841)	$55.50

Assuming an alternative net metering tariff is available improves the economic viability of the B11-R13 PRV project significantly. NPV of electricity service from the project is $188,000 less than electricity service provided by RMP over the 50-year project life. When a cost of CO_2e is incorporated into the cash flow analysis, the economics of the project are strengthened even further. At $25/MTCO$_2$e, NPV is $515,000 less than the business-as-usual scenario; and when the price of carbon is assumed to be $50/MTCO$_2$e, NPV of the project improves to $841,000.

7.6 West Temple Wastewater Heat Recovery Site

The wastewater heat recovery site, located adjacent to DPU's main office in Salt Lake City, would utilize a heat exchanger to extract heat from wastewater flowing in the sewer trunkline along West Temple. A heat exchanger and pump would be utilized to provide space heating to DPU's main office.

The economic analysis at this site was performed assuming the addition of a 156-kW heat exchanger with a 60-kW heat pump tied into the 36-inch sewer trunkline adjacent to the main DPU office building, and that the addition of a new, low-heat delivery system would be integrated with the existing buildings. The upfront capital costs of the wastewater heat recovery system and low temperature heat delivery system was estimated to be $695,000, and the annual non-fuel operating expenses were assumed to be zero. The system is estimated to conserve 1,862 MMBtu of natural gas annually. However, the addition of a heat pump would increase electricity use at DPU's main office by 123.6 MWh each year. Based on these assumptions, NPV of the cost of utility service of the wastewater heat recovery system is estimated to exceed the value of natural gas service provided by Questar by $602,000 over the 30 year-life of the project. At a price of $50/MTCO$_2$e, the project only performs marginally better due to the fact the annual average avoided carbon dioxide emissions from the project is only 41 metric tons per year.

Table 7-7. West Temple Wastewater Heat Recovery NPV of the Cost of Utility Service

Project Site	Type of Power Technology	Use of Generation	Overnight Capital	Non-Fuel Operating Expense	Cost of Utility Service Present Value $Millions			Levelized Cost
			2014$ Millions	2014$ Millions	$0 per MTCO2e	$25 per MTCO2e	$50 per MTCO2e	$ per MWh
DPU Office	Heat Recovery	N/A	$0.695	$0.000	$0.602	$0.584	$0.566	N/A

8.0 POTENTIAL PROJECT FINANCING MECHANISMS

This section of the plan is intended to assist DPU with identifying financing mechanisms to support the deployment of renewable energy technologies on DPU-owned and operated property. While the Consultant Team recognizes it is DPU's preference to internally fund renewable energy projects using revenue from its utility operations, there are opportunities to leverage DPU's available funds with other funding sources to accelerate the deployment of City-owned renewable energy projects and the benefits associated with renewable energy deployment. This includes creating new local-based economic opportunities, increasing diversity of DPU electricity supply, mitigating risk of higher energy prices in the future, and reducing CO_2 emissions.

8.1 Apply for the Utah Solar Incentive Program (USIP)

This program is available to any customer whose bills are subject to the Schedule 195 solar incentive program surcharge. In 2016, the program will provide a $0.85 per-watt incentive for the upfront cost of installing a solar project less than 25-kW in size, or a $0.65 per-watt incentive for a solar project greater than 25-kW in size (with a maximum value of $650,000). The incentive is awarded through a lottery. In 2016, incentives will be available for 4,500-kW of capacity for projects less than 25-kW in size, and 10,000-kW of capacity for projects greater than 25-kW in size. In 2014, RMP awarded incentives to 100 percent of small commercial applicants and 37 percent of large commercial applicants. The USIP cannot be used in conjunction with any other RMP grant or incentive programs, including the Blue Sky Community Grants. For more information and application instructions, see Appendix D.

8.2 Apply for a Blue Sky Community Grant

Renewable energy installations, including hydroelectric projects, can apply to receive a Blue Sky Community Grant. RMP accepts applications for Blue Sky Community grants on an annual basis. Blue Sky grants can only fund up to 60 percent of the total project costs. See Appendix D for more details.

8.3 Consider a PPA

Power Purchase Agreements (PPAs) are available to local governments in Utah for net-metered projects. PPAs are a commonly used financing mechanism for solar installations, offering solar electricity at no upfront cost. PPAs allow a third-party developer to build, own, and maintain a solar photovoltaic system at a DPU facility. DPU would agree to purchase electricity produced by the solar panels at a fixed price for a predetermined time period. This arrangement offers significant cost savings because the third party developer can take advantage of tax credits and pass on the savings to DPU. A PPA can include a "buy-out" option which would allow DPU to purchase the solar facility at a pro-rated price after the tax benefits have been utilized by the developer or investor. See Appendix D for more details.

8.4 Utilize Qualified Energy Conservation Bonds

Qualified Energy Conservation Bonds (QECBs) are a debt instrument that enables qualified states, territories, and local governments to issue tax credit bonds with very low effective interest rates in order to fund energy conservation or renewable energy projects. The State of Utah, Salt Lake City, and Salt Lake County all received a separate allocation for QECBs from the U.S. Department of the Treasury, and the majority of these allocations are still available. For more information about QECBs and how to apply, see Appendix D.

8.5 Finance with the U-Save Energy Fund Program

The U-Save Energy Fund finances energy-related cost reduction retrofits on existing equipment and installations for publically owned buildings by offering loans with low interest rates. A revolving loan mechanism allows borrowers to repay the loans using cost savings realized from the retrofits. Entities considering use of the U-Save Energy Fund are encouraged to evaluate renewable energy technologies, including rooftop solar water and space heating installations, solar photovoltaic, and small wind installations. A revolving loan mechanism allows borrowers to repay the loans using cost savings realized from the retrofits. For more information about the U-Save Energy Fund and instructions for applications, see Appendix D.

9.0 SUMMARY AND CONCLUSIONS

This Plan is a broad framework that identifies DPU's opportunities for renewable energy projects; evaluates their technical, economic, and practical feasibility; and provides strategies and recommendations for their implementation.

The purpose of the plan is to provide DPU with sufficient detail on the final selected 19 renewable energy projects that were evaluated in the Phase II detailed site evaluation to either allow for the subsequent development of renewable energy projects or to identify sites that show potential and are good candidates for additional assessment.

One of the objectives of this analysis was to identify potentially viable renewable energy projects that could increase the diversity of DPU's electricity supply and contribute to growing Salt Lake City's renewable energy portfolio and reducing its GHG footprint. It is clear from this assessment that DPU-managed infrastructure and property can support a diverse portfolio of renewable energy technologies and projects. Among the technologies evaluated at the 19 Phase II selected sites were biogas-fired cogeneration, distributed roof-mounted solar PV, utility-scale roof- and ground-mounted solar PV systems, conventional hydroelectric generation, wastewater heat recovery, and micro-hydroelectric projects. When combined, these sites demonstrate the technical potential to support the installation of renewable energy capacity that would generate 13,690 megawatt-hours (MWh) of electricity, enough to offset approximately 44 percent of the electricity currently purchased from Rocky Mountain Power and Murray City. The renewable energy potential is even greater if all 41 sites that were evaluated in Phase I are accounted for. Including these additional sites raises the renewable energy generation potential to 18,779 MWh.

Of course these numbers only represent the technical potential. Economics and regulatory feasibility are also necessary considerations that need to be accounted for when a decision is made to implement a project. From the outset it was understood that this study would form the foundation and provide guidance for more detailed future evaluations of project sites that could include analysis using more detailed engineering, site, and economic assessments. The scope of work and budget for this study did not allow for a regulatory assessment of rate schedules and economic analysis to be completed for each of the 19 candidate project sites that showed high technical potential. Accordingly, the DPU Steering Committee and Consultant Team selected six representative sites for further analysis that would enable DPU to benchmark the regulatory and economic performance of the remaining 13 sites and technologies for future consideration.

9.1 Economic Analysis

Of the six renewable energy project sites selected for the more detailed regulatory and economic assessment, five sites involved projects that would generate electricity; the Terminal and Park Reservoirs, 15th East Reservoir, Mountain Dell Dam, PRV Station B11-R13, and the Salt Lake City

Water Reclamation Facility biogas cogeneration project. One site, the DPU Campus wastewater heat recovery project, would offset heating load, decreasing the purchases of natural gas.

The combined estimated overnight capital investment required to develop the four solar PV projects and hydroelectric projects is $14.8 million. Based on the generation capacities assumed in this analysis these four projects would be able to generate 6,287 MWh of electricity and avoid 4,735 $MTCO_2e$ of GHG emissions.

The economic analysis of biogas cogeneration at the SLCWRF considered increasing the generation of underutilized capacity of the two engines and replacement with four different technology options utilizing biogas produced at the treatment plant. If the SLCWRF retained the use of the two 700-kW reciprocating engines and operated them to utilize all the available biogas produced at the treat plant, it could avoid any additional capital investment and generate 2,553 MWh more electricity while reducing the GHG emissions associated with SLCWRF operations by 1,558 $MTCO_2e$. An overnight capital investment of between $6.7 and $12.1 million would be required to replace the two existing 700-kW engines with either a new 1400-kW reciprocating engine, an 844-kW micro-turbine or a 1330-kW fuel cell.

For an estimated capital investment of $695,000, DPU could also install wastewater heat recovery technology to supplement heating load at DPU's main office complex. This option would reduce natural gas consumed by the existing boiler by 1,862 MMBTU but increase the electricity consumption by 123.6 MWh, resulting in a net reduction of GHG emissions of 41 $MTCO_2e$.
For purpose of this study, the economic viability of each project is determined by quantifying the NPV of the cost of utility service, as measured by cash flow throughout the life of the project, and then comparing the costs to a business-as-usual case where DPU continues to receive utility service from either RMP or Questar. If NPV is negative, the costs of electricity or natural gas produced by the renewable energy project is less than utility service over the life of the project. Therefore, the project is economical.

While all six projects were technically feasible and provided good locations for the development of renewable energy, only one project proved to be economically viable under the current regulatory, utility pricing, and economic assumptions adopted for this analysis. Using the NPV of the cost of utility service as the metric for demonstrating financial viability, only the SLCWRF biogas cogeneration was able to meet this cost effectiveness threshold. An operational change would allow DPU to operate both 700-kW engines to utilize all the biogas produced by the plant with no additional capital investment. This technology option proved cost effective whether both engines were operated using biogas or supplemented with natural gas to maximize generation capacity.

Table 9-1. Economic Ranking of Renewable Energy Projects
(Net Present Value of the Cost of Utility Service)

Project Site	Type of Power Technology	Use of Generation	Overnight Capital	Non-Fuel Operating Expense	Cost of Utility Service Present Value $Millions			Levelized Cost
			2014$ Millions	2014$ Millions	$0 per MTCO2e	$25 per MTCO2e	$50 per MTCO2e	$ per MWh
SLCWRF	Existing Recip (Biogas)	Schedule 31	$0.000	$76.579	($1.458)	($1.996)	($2.533)	$26.50
SLCWRF	Existing Recip (Biogas/NG)	Schedule 31	$0.000	$109.272	($0.273)	(0.697)	($1.120)	$35.50
PRV Station B11-R13	Micro-Hydro	Virtual Net Metering	$0.999	$0.015	($0.188)	($0.515)	($0.841)	$55.50
Mountain Dell Dam	Hydroelectric	Net Metered	$1.551	$0.019	$0.355	$0.064	($0.228)	$92.00
15th East Reservoir	Solar PV	Net Metered	$0.920	$0.013	$0.426	$0.314	$0.202	$153.50
PRV Station B11-R13	Micro-Hydro	Schedule 37	$0.999	$0.015	$0.585	$0.258	($0.068)	$55.50
DPU Office	Heat Recovery	N/A	$0.695	$0.000	$0.602	$0.584	$0.566	N/A
Terminal Park Reservoir	Solar PV	Virtual Net Metering	$11.292	$0.150	$2.354	$0.898	($0.559)	$139.50
Terminal Park Reservoir	Solar PV	Schedule 37	$11.292	$0.150	$10.155	$8.699	$7.242	$139.50

The economic analysis also included a sensitivity analysis that incorporated a cost of carbon into the cash flow analysis to account for potential future GHG regulations and the additional costs it would add to electricity generated from fossil fuels. The assumed cost of carbon for this sensitivity analysis was $25/MTCO$_2$e and $50/MTCO$_2$e. The economic viability of the six projects improved when a price for carbon dioxide was incorporated into the cash flow analysis to account for future fuel price and regulatory risk of GHG regulations. The point to be made about the results of this price sensitivity scenario is that DPU can view the development, generation, and use of electricity from on-site renewable energy projects as a hedge against fuel and energy price increases due to future GHG regulations.

A second sensitivity analysis assumed the generation from the PRV station B11-R13 and Terminal and Park Reservoirs could be used to offset electricity consumed at other DPU facilities through an alternative net metering arrangement (which is not currently available in Utah). Under this assumption, NPV of the PRV Station B11-R13 project exceeds the value of utility service provided by RMP under all cost-of-carbon regulation scenarios. The Terminal and Park Reservoirs solar PV project was still uneconomical under the $0 and $25/MTCO$_2$e cost assumptions but became economically viable when a price of $50/MTCO$_2$e was incorporated into the cash flow analysis. Economics of all the projects evaluated could be improved through DPU adopting some form of third party alternative financing such as a lease or a PPA.

9.2 GHG Emissions

Considering the six renewable energy projects from the standpoint of their contribution to reducing DPU's GHG emissions footprint, the Terminal and Park Reservoirs project has the biggest impact by avoiding 3,381 $MTCO_2e$. This represents approximately 13 percent of the GHG emissions associated with DPU's consumption of purchased electricity and natural gas. The two SLCWRF cogeneration options, where biogas and biogas plus supplemental natural gas are burned to enable the existing engines to run a higher capacity factors, contribute the next largest GHG emissions reductions, avoiding 1,553 and 1,233 $MTCO_2e$.

If DPU developed all six renewable energy projects, it is estimated it could reduce its GHG emissions footprint by 6,228 $MTCO_2e$, or 25 percent.

Table 9-2. Estimated Avoided GHG Emissions by Project

Project Site	Type of Power Technology	Use of Generation	Average Annual Generation	Annual GHG Emissions
			MWh	MTCO2e
SLCWRF	Existing Recip (Biogas)	Schedule 31	2,553	1,553
SLCWRF	Existing Recip (Biogas/NG)	Schedule 31	3,642	1,233
PRV Station B11-R13	Micro-Hydro	Virtual Net Metering	773	582
Mountain Dell Dam	Hydroelectric	Net Metered	690	520
15th East Reservoir	Solar PV	Net Metered	335	252
PRV Station B11-R13	Micro-Hydro	Schedule 37	773	582
DPU Office	Heat Recovery	None	(124)	41
Terminal Park Reservoir	Solar PV	Virtual Net Metering	4,489	3,381
Terminal Park Reservoir	Solar PV	Schedule 37	4,489	3,381

9.3 Rate Schedule Assessment

The regulatory rate schedule assessment evaluated tariff options at each of the renewable energy project sites to determine what tariff rate options were available and would maximize the economic benefits of the proposed renewable energy projects.

The first question addressed was whether the site was on the most appropriate tariff given existing consumption of electricity. Two sites, Mountain Dell and the 15th East Reservoir, are currently receiving power on Schedule 6A, a "time-of-use" tariff, that charges higher rates for electricity consumed during "on-peak" hours and charges significantly lower rates during off-peak hours. In the absence of a renewable energy project at either site, Schedule 6A may not be the appropriate rate schedule or offer the best pricing.

The next question considered at each potential renewable energy site was whether the project would produce electricity that would contribute to meeting load or would generate excess at the site. If excess generation is likely from the new renewable project then options for selling electricity back to RMP were evaluated and considered in the context of maximizing the value DPU would receive for the additional generation.

Based on price, the most advantageous rate RMP currently offers for renewable energy projects is Schedule 135—Net Metering. This tariff is offered to customers with on-site renewable facilities to be connected to the grid and receive credit for excess electricity produced but not consumed at the site. Thus the customer is billed for their "net usage" over the course of a month.

Additionally, for the cogeneration development at the SCLWRF, or the renewable energy projects at the Terminal and Park Reservoirs, 15th East Reservoir, or the B11-R13 PRV station, excess sales to the grid are currently governed by either Schedule 37 (less than 1-MW for cogeneration or less than 3-MW for other renewable projects), or Schedule 38 (greater than 1-MW for cogeneration or greater than 3-MW for other renewable projects). In either case, selling electricity to the grid serves as an important offset to the capital investment incurred with the renewable generation development.

Other rate considerations include the new Schedule 32, which would allow DPU to source a large portion of its electrical service from renewable resources obtained from sources other than RMP. This rate will soon be finalized by the Public Service Commission, and it will offer an alternative option for DPU. The rate has a 2-MW threshold, so aggregation of generation from smaller facilities will be critical for all projects except the Terminal and Park Reservoirs. DPU could aggregate a portfolio of renewable energy sites located throughout Salt Lake City which collectively meet the 2-MW threshold.

9.4 Financing

There are opportunities to leverage DPU's available funds with other funding sources to lower the upfront capital costs and accelerate the deployment of City-owned renewable energy projects. All of the funding sources and financing mechanisms identified by the Consultant Team are viable options for lowering the upfront capital investment required by DPU. Moreover, from the perspective of DPU, lowering the capital investment will improve the economic viability of the projects that receive supplemental funding.

10.0 RECOMMENDATIONS

10.1 Renewable Energy Projects

Based on the analysis conducted by the project team, the following recommendations are offered for action in the near-term:

1. Salt Lake City Wastewater Reclamation Facility

The SLCWRF's existing cogeneration units offer the best and most cost-effective near-term opportunity for DPU to increase the generation of electricity from renewable energy sources and significantly reduce its carbon footprint. DPU should:

- Implement changes in the operations of the existing cogeneration engines at the site. There is sufficient biogas produced at the site to increase utilization of the existing engines by 50percent without running up against limitations placed on the amount of electricity the SLCWRF can produce under RMP's Tariff Schedule 31.
- More fully utilize existing digester gas production capacity by incorporating a fats, oils and grease (FOG) collection program and add this waste stream to the digesters at the SLCWRF. This would increase the production of biogas and enable the cogeneration engines to operate at near capacity.
- In the absence of a FOG program, SLCWRF should supplement the biogas burned by the cogeneration engines with natural gas. While the GHG emissions reduction benefits are decreased, burning natural gas in combination with biogas is still economic from a cost of utility service perspective.
- Evaluate the regulatory opportunity and economics of generating excess power for sale to RMP under Schedules 37 or 38, or to deliver excess generated electricity to one of DPU's other electricity loads under Schedule 32.

2. 15th East Reservoir Site

The 15th East Reservoir site is an excellent candidate for a solar PV installation from a location, resource, and technology standpoint. A 274-kW solar installation was evaluated at the 15th East Reservoir site and proved to be uneconomical from a NPV cost of utility service perspective. However, the 274-kW system would generate almost five times more electricity than is necessary to meet the needs of the reservoir's operations. A net-metered, 25-kW installation sized to offset on-site electricity usage would significantly reduce the upfront capital costs and improve the economic viability of the project. This site is a strong candidate for a solar PV project and additional analysis should be conducted by DPU to further evaluate design alternatives, regulatory strategies, and alternative financing options that could improve its economic viability. DPU should evaluate:

- Whether the electric service at the 15th East Reservoir site could be aggregated with electric meters at the adjacent Rice Eccles Stadium to take full advantage of net metering and the 274-kW solar generation capacity the site would support.
- The economic advantages of a third party project financing mechanism such as a lease or a PPA. This would allow DPU to take advantage of a federal tax incentive through a third-party ownership structure, which could reduce the cost by 30 percent and improve the economics of the project.
- Evaluate the economics of a solar PV system that is designed to optimize the size of the system based on on-site load. At a minimum, it will reduce the upfront capital costs of the project and significantly improve the NPV cost of utility service over the life of the project.

3. Mountain Dell Dam Hydroelectric Project

The Mountain Dell Reservoir hydroelectric project is considered an attractive site for development because of the ease of interconnection to existing load, and the potential for the hydroelectric power system to be net metered and offset 75 percent of the power currently purchased from RMP at $0.1128 per kWh. The project proved economical on a NPV basis when price of $50/$MTCO_2e$ is assumed in the cash flow analysis. There is an opportunity to significantly improve the financial viability of this project and reduce DPU's upfront capital costs through a lease or a PPA. DPU should investigate this type of arrangement before the federal tax incentives expire at the end of 2016.

4. Pressure Release Valve Station B11-R13 Micro-Hydroelectric Project

Like the Mountain Dell hydroelectric project, the PRV B11-R13 micro-hydro project was economically viable when a price of $ 50/$MTCO_2e$ was used in the cash flow analysis to account for the potential costs of future GHG regulations. Because of the number of PRV stations operated by DPU, the successful demonstration of the technical viability of this technology at the PRV B11-R13 station site creates the opportunity to develop many more micro-hydroelectric sites in the DPU water system. From the standpoint of DPU, the economics of this project and others could be improved further by leveraging the federal renewable energy tax incentives to attract a third party development partner who could take advantage of the tax credits, and financing that would offset a portion of the upfront capital costs of the project.

5. Terminal and Park Reservoir Solar PV Project

The Terminal and Park Reservoir site could support a 3.5-MW solar PV installation capable of generating an annual average of 4,490,000 kWh. The only circumstance where the Terminal Park Reservoirs site would provide lower cost electricity service compared to RMP is by assuming an alternative net metering tariff is available to DPU at the equivalent of the average retail rate for Schedule 6A (i.e., 11.28 cents per kWh), and including a $50/$MTCO_2e$ in the cash flow analysis. Like the other renewable energy projects that require a major capital investment, there is an opportunity to significantly improve the financial viability of this project and reduce DPU's up-front capital costs through a lease or a PPA with a third party who can take advantage of the federal tax incentives.

This is the single largest renewable energy project opportunity among the 151 project sites evaluated and it provides the greatest opportunity to offset RMP electricity purchases and reduce DPU's carbon footprint. DPU should investigate the opportunity to enter into third party alternative financing arrangement before the federal tax incentives expire at the end of 2016 as a strategy to improve the economics of the project.

6. Solar Photovoltaic (PV) Rooftop Projects

Solar PV rooftop projects scored very high relative to all projects in the detailed site evaluations but were not selected for regulatory and economic analysis in Phase II. PV rooftop systems offer the opportunity to offset each kWh generated at the full costs of power delivered to DPU facilities by local electricity providers, and are scalable to the available space on a building. DPU should conduct a more complete evaluation of all available roof space and the economic viability of these systems. Moreover, because of the renewable energy opportunity offered by solar PV, Salt Lake City government should consider adopting construction standards for new and renovated buildings that require consideration of solar PV and integrate solar-ready building techniques into future construction or renovation. To improve the economics of rooftop solar, DPU should apply for the Utah Solar Incentive Program. This program awards an incentive for solar projects through a lottery and will expire after January 2017. DPU should also consider using a PPA to leverage the 30 percent federal tax credit that expires in 2016.

7. DPU Main Office Wastewater Heat Recovery Project

A wastewater heat recovery project adjacent to DPU's main office in Salt Lake City would utilize a heat exchanger/heat pump to extract heat from wastewater flowing in the sewer trunkline along West Temple, and provide supplemental space heating to DPU's main office. The heat exchanger/heat pump system for this project can also be configured to provide cooling during the summer months. The screening level data and design parameters used for this analysis did not provide sufficient detail to enable evaluation of the cooling capabilities of this technology. If DPU is interested in a more detailed investigation of this technology, it is recommended that the City evaluate the cooling capability of reconfiguring wastewater heat recovery technology to be tied to the existing HVAC system.

10.2 Regulatory

1. Salt Lake City Wastewater Reclamation Facility

SLCWRF is currently constrained from operating its two 700 kW-reciprocating engine cogeneration system at full capacity due to prohibitions against generation exceeding load at the site. In order to take full advantage of the economic and environmental benefits of available biogas and underutilized cogeneration capacity, DPU should evaluate the regulatory implications and economics of generating excess electricity under the various rate schedules associated with its on-site generation capacity, i.e., Schedules 31 and 9. Neither Schedule 31 nor Schedule 9 allows net metering or selling excess power back to RMP. However, as a facility taking service under Schedule 31, SLCWRF might

be able to sell excess electricity back to the utility at wholesale “avoided costs” rates using either Schedule 37 (if the capacity sold is less than 1-MW) or Schedule 38 (if greater than 1-MW).

2. Mountain Dell Hydroelectric Project

The Parley’s Canyon Water Treatment Plant is currently receiving electricity service through Schedule 6A. Based on the load shape of electricity use at this site, Schedule 6A might not be best tariff. DPU should assess whether the water treatment plant is eligible for a different tariff. If the hydroelectric project is developed at Mountain Dell, this site is a good candidate for net metering on Schedule 135.

3. Pressure Release Valve Station B11-R13 Micro-Hydroelectric Project

A micro-hydro project installed at the PRV station B11-R13 will generate more electricity than there is load at the site. DPU should certify this PRV project as a QF and make it eligible to sell power back to RMP under Schedule 37.

4. Electric Service Schedule 32

End use customers utilizing Schedule 32 must contract to take more than 2-MW of electricity delivery; however, the law permits multiple renewable energy facilities to deliver electricity to a single contract customer. Given the multiple renewable opportunities identified by this study, DPU should evaluate whether or not it would be feasible and economic to build a 2-MW portfolio of projects to serve DPU loads under this tariff.

5. Alternative Net Metering

Alternative net metering policies improved the economics of the Terminal and Park Reservoirs, and PRV B11-R13 projects. As a leader and advocate for clean energy and the environment, Salt Lake City should consider advocating for regulatory policies that allow the City to use credits generated at one facility to offset electrical bills at another facility.

10.3 Alternative Financing

1. Utah Solar Incentive Program

Due to the number of Solar PV development opportunities, DPU should apply for the Utah Solar Incentive Program for both small solar PV (less than 25-kW) and large solar projects up to 1-MW to fund projects. The current program will sunset in 2017.

2. Lease and Power Purchase Agreements

There are alternative financing opportunities to leverage DPU’s available funds with other funding sources to lower the upfront capital costs and accelerate the deployment of City-owned renewable energy projects. DPU should consider lease structures or PPAs as a financing mechanism that reduces cost through tax incentives. The current 30 percent federal tax credit is set to revert to 10 percent at the end of 2016.

Appendix A

Phase I Evaluation Matrix

				Generation Points			Site Charateristics Points													Environmental Points						
Tank Name	Capacity (kW)	Annual AC Energy (kWh)	On-Site or Adjacent Loads	Initial Points	Weighting Factor	Weighted Points	Potential to Offset Existing DPU Load	Initial Points	Weighting Factor	Potential to Interconnect	Initial Points	Weighting Factor	Distance to Distribution Infrastructure	Initial Points	Weighting Factor	% DPU Load Displaced	Initial Points	Weighting Factor	Weighted Points	Impact	Acceptance	Initial Points	Weighting Factor	Weighted Points	Total Poiint	Comments
Water Tank/Reservoir - Roof Mount																										
Terminal Reservoirs/Park Reservoir	1,562	2,280,520	Wells 3580 E #4 & #5	5	5	25	Yes	3	2	Yes	5	2	<0.2 mi	4	4	100	5	2	42	Negligible	100%	5	5	25	92	
Baskin Reservoir	395	576,700	Bonneville PS	4	5	20	Yes	3	2	Yes	5	2	<0.2 mi	4	4	34	2	2	36	Negligible	100%	5	5	25	81	
15th East Reservoir	290	423,400	500 S Well & University PS	3	5	15	Yes	5	2	Yes	5	2	<0.1 mi	5	4	No data	1	2	42	Negligible	100%	5	5	25	82	
Military Reservoir	256	373,760	Military PS	3	5	15	Yes	5	2	Yes	5	2	<0.1 mi	5	4	15	1	2	42	Major	<50%	0	5	0	57	Reservoir is used as a park
Victory Road Reservior	248	362,080		3	5	15	No	0	2	Yes	5	2	<0.3 mi	3	4	0		2	22	Negligible	100%	5	5	25	62	
Wilson Reservoir	241	351,860	Arlington Hills PS	3	5	15	Yes	5	2	Yes	5	2	<0.1 mi	5	4	25	2	2	44	Negligible	100%	5	5	25	84	
Marcus Reservoir	190	277,400		3	5	15	No	0	2	Yes	5	2	<0.1 mi	5	4	0		2	30	Negligible	100%	5	5	25	70	
Morris Reservoir	176	256,960	North Bench PS	3	5	15	Yes	5	2	Yes	5	2	<0.1 mi	5	4	86	5	2	50	Negligible	100%	5	5	25	90	
McEntire Reservoir	142	207,320		2	5	10	No	0	2	Yes	5	2	<0.1 mi	5	4	0		2	30	Major	<50%	0	5	0	40	Reservoir is used as a park
13th East Reservoir	114	166,440		2	5	10	No	0	2	Yes	5	2	<0.1 mi	5	4	0		2	30	Major	<50%	0	5	0	40	Reservoir is used as a park
Ensign Downs Lower Tank	105	153,300	Ensign Downs PS	2	5	10	Yes	5	2	Likely	3	2	<0.3 mi	3	4	No data	1	2	30	Negligible	100%	5	5	25	65	
Tanner Reservoir	67	97,820	Dyers Inn Well	1	5	5	Yes	5	2	Yes	5	2	<0.1 mi	5	4	4	1	2	42	Negligible	100%	5	5	25	72	Low generation but DPU load on-site
Granite Oaks Tank/Telford Reservoir	54	78,840	Granite Oaks PS	1	5	5	Yes	5	2	Yes	5	2	<0.1 mi	5	4	No data	1	2	42	Negligible	100%	5	5	25	72	Low generation but DPU load on-site
Tavaci Tank	47	68,620	Tavici PS	1	5	5	Yes	2	2	Maybe	1	2	<0.5 mi	1	4	No data	1	2	12	Negligible	100%	5	5	25	42	Low generation but DPU load on-site
Mt Opympus Tanks	45	65,700	Mount Olympus PS	1	5	5	Yes	5	2	Yes	5	2	<0.1 mi	5	4	9	1	2	42	Negligible	100%	5	5	25	72	Low generation but DPU load on-site
East Bench Tanks	38	55,480	Carrigan Cove PS	1	5	5	Yes	5	2	Yes	5	2	<0.1 mi	5	4	69	4	2	48	Negligible	100%	5	5	25	78	Low generation but DPU load on-site
Eastwood Tanks	14	20,440	Eastwood PS	1	5	5	Yes	5	2	Yes	5	2	<0.1 mi	5	4	4	1	2	42	Negligible	100%	5	5	25	72	Low generation but DPU load on-site
Millcreek Tank	2	2,920	Lower Boundary PS	1	5	5	Yes	5	2	Yes	5	2	<0.1 mi	5	4	1	1	2	42	Negligible	100%	5	5	25	72	Low generation but DPU load on-site
Buildings - Roof Mount																										
Boeing	733	1,070,180	Building Load	5	5	25	Yes	5	2	Yes	5	2	<0.1 mi	5	4	No data	1	2	42	Negligible	100%	5	5	25	92	
XPEDX	456	665,760	Building Load	4	5	20	Yes	5	2	Yes	5	2	<0.1 mi	5	4	No data	1	2	42	Negligible	100%	5	5	25	87	
Highland High School	333	486,180	Building Load	3	5	15	Yes	5	2	Yes	5	2	<0.1 mi	5	4	No data	1	2	42	Negligible	100%	5	5	25	82	
Roberts Restaurant and Adjacent Building	267	389,820	Building Load	3	5	15	Yes	5	2	Yes	5	2	<0.1 mi	5	4	No data	1	2	42	Negligible	100%	5	5	25	82	
410 N. Wright Brothers Drive	228	332,880	Building Load	3	5	15	Yes	5	2	Yes	5	2	<0.1 mi	5	4	No data	1	2	42	Negligible	100%	5	5	25	82	
Salt Lake City Sports Complex	187	273,020	Building Load	3	5	15	Yes	5	2	Yes	5	2	<0.1 mi	5	4	No data	1	2	42	Negligible	100%	5	5	25	82	
The Leonardo	91	132,860	Building Load	2	5	10	Yes	5	2	Yes	5	2	<0.1 mi	5	4	No data	1	2	42	Minor	90%	4	5	20	72	
Sorenson Multicultural and Unity Fitness Center	58	84,680	Building Load	1	5	5	Yes	5	2	Yes	5	2	<0.1 mi	5	4	No data	1	2	42	Negligible	100%	5	5	25	72	
SLCDPU Buildings	57	83,220	Building Load	1	5	5	Yes	5	2	Yes	5	2	<0.1 mi	5	4	7	1	2	42	Negligible	100%	5	5	25	72	
Open Parcel - Ground Mount																										
South Lift	299	436,540	South Sewer LS	3	5	15	Yes	5	2	Yes	5	2	<0.1 mi	5	4	100	5	2	50	Negligible	100%	5	5	25	90	
Smith & Loveless	85	124,100	Smith & Loveless and 4000 W Sewer LS	2	5	10	Yes	5	2	Maybe	1	2	<0.3 mi	5	4	No data	1	2	34	Moderate	100%	1	5	5	49	
Concord Lift	79	115,340	Concord Sewer LS	2	5	10	Yes	5	2	Yes	5	2	<0.1 mi	5	4	100	5	2	50	Negligible	100%	5	5	25	85	
6200 S. Well	63	91,980	6200 S Well & 6200 S Irrigation PS	1	5	5	Yes	5	2	Yes	5	2	<0.1 mi	5	4	5	1	2	42	Negligible	100%	5	5	25	72	
Greenfield Village	51	74,460	Greenfield Village Well	1	5	5	Yes	5	2	Yes	5	2	<0.1 mi	5	4	6	1	2	42	Negligible	100%	5	5	25	72	

Facility ID	Capacity (kW)	Annual Generation (kWh)	On-Site or Adjacent Loads	Generation Points: Initial Points	Generation Points: Weighting Factor	Generation Points: Weighted Points	Site Charateristics Points: Potential to Offset Existing DPU Load	Initial Points	Weighting Factor	Potential to Interconnect	Initial Points	Weighting Factor	Distance to Distribution Infrastructure	Initial Points	Weighting Factor	% DPU Load Displaced	Initial Points	Weighting Factor	Weighted Points	Environmental Points: Impact	Acceptance	Initial Points	Weighting Factor	Weighted Points	Total Poiint	Comments
PRV																										
D74-DV1	359	1,310,352		5	5	25	No	0	2	Maybe	1	2	<0.3 mi	3	4	0	0	2	14	Negligible	100%	5	5	25	64	
B35-R18	422	1,539,757		5	5	25	No	0	2	Yes	5	2	<0.1 mi	5	4	0	0	2	30	Negligible	100%	5	5	25	80	
B11-R13	292	1,064,622		5	5	25	No	0	2	Yes	5	2	<0.1 mi	5	4	0	0	2	30	Negligible	100%	5	5	25	80	
C41-R20	281	1,025,114		5	5	25	No	0	2	Yes	5	2	<0.1 mi	5	4	0	0	2	30	Negligible	100%	5	5	25	80	
B6-R73	266	970,091		4	5	20	No	0	2	Yes	5	2	<0.1 mi	5	4	0	0	2	30	Negligible	100%	5	5	25	75	
D69-R40	63	228,660		2	5	10	No	0	2	Yes	5	2	<0.1 mi	5	4	0	0	2	30	Negligible	100%	5	5	25	65	
A23-R5	59	216,797		2	5	10	No	0	2	Yes	4	2	<0.1 mi	5	4	0	0	2	28	Negligible	100%	5	5	25	63	
C1-R74	54	196,973		2	5	10	No	0	2	Yes	5	2	<0.1 mi	5	4	0	0	2	30	Negligible	100%	5	5	25	65	
F78-CR28	41	151,340		2	5	10	No	0	2	Maybe	1	2		1	4	0	0	2	6	Negligible	100%	5	5	25	41	
G35-CR53	36	131,639	Private Well	2	5	10	Yes	4	2	Yes	5	2	<0.1 mi	5	4	0	0	2	38	Negligible	100%	5	5	25	73	
G38-CR57	17	62,052	7800 S PS	1	5	5	Yes	4	2	Yes	5	2	<0.1 mi	5	4	7	1	2	40	Negligible	100%	5	5	25	70	Low generation but DPU load on-site
Surface Water																										
Mountain Dell Dam	410	2,370,536	Parley's WTP	5	5	25	Yes	5	2	Yes	5	2	<0.1 mi	5	4	100	5	2	50	Minor	100%	4.5	5	22.5	98	
Big Spill	15	65,520	On-site pump, lighting and gates	1	5	5	Yes	5	2	Likely	3	2	<0.4 mi	2	4	100	5	2	34	Minor	100%	4.5	5	22.5	62	Low generation but DPU load on-site

Appendix B

Technical Memorandum – Cogeneration Assessment
Carollo Engineers

SALT LAKE CITY
DEPARTMENT OF PUBLIC UTILITIES

TECHNICAL MEMORANDUM
COGENERATION ASSESSMENT

REVISED FINAL
November 2014

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SALT LAKE CITY
DEPARTMENT OF PUBLIC UTILITIES

TECHNICAL MEMORANDUM
COGENERATION ASSESSMENT

TECHNICAL MEMORANDUM

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1.0 INTRODUCTION

1.1 Background

The Salt Lake City Water Reclamation Facility (SLCWRF) treats up to 56 million gallons of wastewater a day and is owned and operated by the Salt Lake City Department of Public Utilities (SLCDPU). SLCWRF is located on the north end of the City at 2300 North, between Redwood Road on the West and the Oil Drain Canal on the East. SLCWRF was originally constructed in the early 1960s, and has undergone numerous upgrades and expansions since then.

Currently, a combined trickling filter and activated sludge process is used at SLCWRF to remove organic wastes and treat wastewater prior to its release back to the environment. Waste activated solids are co-settled with primary solids in the primary clarifiers, thickened through gravity thickeners, mixed with scum collected from process basins and stabilized in anaerobic digesters. After digestion, solids are dried in solar dying beds and hauled away for use as daily cover at the county landfill.

Digester gas, consisting of mostly methane, is collected and cleaned prior to combustion in engine generators for energy recovery and a boiler for digester heating needs. Energy recovered through the combustion of digester gas offsets the amount of power that must be purchased from the local energy utility. An excess digester gas above what can be used in the engine generators or boiler is destroyed by flare.

The purpose of this technical memorandum is to provide an assessment of cogeneration at SLCWRF as part of a larger citywide review of possible alternative energy projects.

1.2 Scope

The following alternatives were developed and evaluated based on life cycle costs and other evaluation parameters.

- Alternative 1 – Use Existing Cogeneration Engines – Run one engine with no natural gas supplementation.
- Alternative 2 – Use Existing Cogeneration Engines – Run two engines with no natural gas supplementation.
- Alternative 3 – Use Existing Cogeneration Engines – Run two engines with natural gas supplementation.

- Alternative 4 – Replace Existing Engines with a New Engine.
- Alternative 5 – Replace Existing Engines with New Microturbine.
- Alternative 6 – Replace Existing Engines with New Fuel Cell.

Each of these alternatives was evaluated based on digester gas production from two treatment process configurations, the current wastewater treatment process and a future biological nutrient removal (BNR) process.

2.0 BACKGROUND

2.1 Existing Cogeneration System

The existing system consists of two 700-kilowatt (kW) engine-generators. The cogeneration system provides electrical energy production and heat for the anaerobic digesters. SLCDPU's desire to minimize future energy costs, limit their greenhouse gas emissions, and better utilize the renewable energy available has prompted this cogeneration assessment. Allowing the existing system to become non-operative due to age, lack of available parts, or catastrophic failure will result in significantly higher energy costs, an increase in associated energy related greenhouse gas emissions, and will put the SLCDPU at greater economic risk due to potential volatile energy prices.

2.2 Current Gas Production

For 2013, SLCWRF's monthly gas production has ranged from 224,000 cf/d to 466,000 cf/d and averaged 358,000 cf/d (Table 1). The cogeneration system can produce a portion of the SLCWRF demands, but power must still be purchased.

The specific gas production rate can then be estimated by dividing the gas production by the measured volatile solids reduction (VSR). Generally, the specific gas production rate falls within a range of 12 to 18 cf/lb VS destroyed. Numbers outside of this range can indicate problems with either the gas meters or the sludge meters.

SLCWRF uses two different methods to measure their digester feed flow (a flow meter and a stroke counter) and two different methods to measure their digester feed total solids (TS) (density meter and lab samples) from both of their gravity thickeners. By combining these two different sludge flows and two different total solids concentrations, SLCWRF can compute four different digester feed TS loads as summarized below:

- Sludge flow meter combined with the lab sample for TS (FM-LS)
- Sludge flow meter combined with the density meter reading for TS (FM-DM)
- Stroke counter converted to flow combined with the lab sample for TS (SC-LS)

- Stroke counter converted to flow combined with the density meter reading for TS (SC-DM).

Table 1 2013 Monthly Average Gas Production
Cogeneration Assessment
SLCDPU

Month	Monthly Average Gas Production, cf/d
January	348,816
February	455,833
March	466,207
April	448,769
May	418,890
June	334,578
July	273,332
August	246,574
September	223,786
October	347,566
November	303,693
December	430,773
2013 Average	**358,235**

The digester feed volatile solids (VS) load was then calculated by multiplying each of the four different feed TS loads by the lab measured ratio of digester VS to TS resulting in the same four different digester feed VS load calculations.

It was assumed that the flow into the digester equaled the flow out of the digester and so the same two flow measurements, FM-LS and SC-LS, were used to calculate two digester VS loads.

The mass of volatile solids reduced (VSR) was then calculated four different ways by subtracting the two different digester VS loads from the four different digester feed VS loads:

Digester Feed VS (FM-LS) – Digester Sludge VS (FM-LS)

Digester Feed VS (FM-DM) – Digester Sludge VS (FM-LS)

Digester Feed VS (SC-LS) – Digester Sludge VS (SC-LS)

Digester Feed VS (SC-DM) – Digester Sludge VS (SC-LS)

Table 2 summarizes the monthly average VSR using the four different calculation methods. SLCWRF staff generally believes that the SC-LS data is the most accurate. As shown in Table 2, the yearly average VSR ranges from a low of 19,023 ppd (SC-LS) to a high of 24,488 ppd (FM-DM).

Table 2 2013 Monthly Average Volatile Solids Reduction Cogeneration Assessment SLCDPU

Month	VSR, ppd FM- LS	VSR, ppd FM-DM	VSR, ppd SC-LS	VSR, ppd SC-DM
January	23796	30384	22423	28205
February	27206	22490	18426	14694
March	27304	26749	23880	23761
April	26352	23073	24844	20913
May	28254	26860	23055	21986
June	28480	28805	19488	19624
July	21454	24381	17006	19209
August	16072	18704	13280	15462
September	15895	18241	11338	13329
October	22956	25878	17903	19994
November	22844	21231	15509	14623
December	21179	27245	19472	24891
2013 Average	23592	24488	19023	19649
Average Difference from SC-LS	+24%	+29%	--	+3%

The estimated specific gas production rate can be estimated by dividing the monthly gas production by the monthly VSR. These values are summarized in Table 3. The 2013 average specific gas production rate ranged from a low of 14.7 cf/lb for the FM-DM samples to a high of 19.1 cf/lb for the SC-LS samples. The VSR calculated using the flow meter yield specific gas production rates that are within the typical range, while the VSR calculated

using the stoke counter yield specific gas production rates that are slightly higher than the typical range. Since the SLCDPU has the most confidence in their SC-LS measurements, a specific gas production rate of 19.1 cf/lb was selected for planning purposes.

Table 3 2013 Monthly Average Specific Gas Production Rates
Cogeneration Assessment
SLCDPU

Month	cf/lb FM-LS	cf/lb FM-DM	cf/lb SC-LS	cf/lb SC-DM
January	14.7	11.5	15.6	12.4
February	16.8	20.3	24.7	31.0
March	17.1	17.4	19.5	19.6
April	17.0	19.5	18.1	21.5
May	14.8	15.6	18.2	19.1
June	11.7	11.6	17.2	17.0
July	12.7	11.2	16.1	14.2
August	15.3	13.2	18.6	15.9
September	14.1	12.3	19.7	16.8
October	15.1	13.4	19.4	17.4
November	13.3	14.3	19.6	20.8
December	20.3	15.8	22.1	17.3
2013 Average	15.3	14.7	19.1	18.6

2.3 Digester Gas Production Projections

The gas production was estimated for current flows and loads for three different operational schemes:

Co-thickening – No biological nutrient removal (BNR): Currently the plant co-thickens WAS in their primary clarifiers. The 2014 WRF Capacity Evaluation (Water Works Engineering) reports a fairly high primary clarifier TSS removal rate of 75% that they suggest could be due to the co-thickening operation. In this configuration, the digester feed VS is

around 28,000 ppd (as calculated using the SC-LS method) and they achieve approximately 66% VSR.

Separate thickening/mechanical dewatering – No BNR: In this configuration, the plant would be operated as it is currently configured except that the WAS would be separately thickened and the sludge drying beds would be replaced with mechanical dewatering. For this configuration, a lower primary clarifier TSS removal rate was assumed of 69%. Additionally, 95% capture was assumed for the WAS thickening and 90% capture was assumed for the mechanical dewatering. This configuration resulted in a higher VS load to the digesters and a slightly lower VSR due to a increase in the WAS to PS ratio in the digester feed.

Separate thickening – BNR: In this configuration, the plant would be operated for BNR with separate thickening of the WAS. This configuration resulted in a lower VS load than the separate thickening configuration with no BNR due to the longer solids retention time in the aeration basins, which resulted in a decrease in the VS load to the digester and a decrease in the degradability of the WAS VS. A low and a high gas production were calculated for this configuration because there was concern that conversion to BNR could reduce the specific gas production rate. The high gas production rate was estimated assuming a specific gas production rate of 19.1 cf/lb and a low gas production rate was estimated assuming a specific gas production rate of 15 cf/lb.

Table 4 summarizes the 2013 estimated gas production from each of these configurations. As shown in Table 4, separate thickening is estimated to increase the gas production by approximately 20% and operation in a BNR configuration (with separate thickening) is estimated to decrease the gas production by approximately 7%. Future gas production was estimated for each configuration by increasing the digester VS load by the projected increase in the equivalent population. 2040 gas production rates were estimated to range from 316,000 cf/d for BNR with the low specific gas production rate of 15 cf/d to a high of 538,000 cf/d with no BNR.

3.0 COGENERATION TECHNOLOGIES

Cogeneration equipment was sized to efficiently and economically utilize the digester gas generated at SLCWRF. Various types of cogeneration technologies can be employed to produce power from digester gas. The following section summarizes each of the technologies and presents the specific model and size of the technology considered for SLCWRF. Manufacturer information from equipment vendors is included in Appendix A for Reference.

Table 4 Estimated Gas Projection
Cogeneration Assessment
SLCDPU

Year	Current Configuration No BNR	Separate Thickening No BNR	Separate Thickening BNR
2013	Dig Feed = 28,000 ppd VSR = 67% VSR = 19,000 ppd Gas = 358,000 cf/d	Dig Feed ~ 35,000 ppd VSR ~ 64% VSR ~ 22,000 ppd Gas ~ 425,000 cf/d	Dig Feed ~ 31,000 ppd VSR ~ 56% VSR ~ 17,000 ppd Gas ~ 332,000 cf/d (high) Gas ~ 261,000 cf/d (low)
2040	NA	Gas ~ 538,000 cf/d	Gas ~ 400,000 cf/d (high) Gas ~ 316,000 cf/d (low)

3.1 Conventional Reciprocating Engines

Reciprocating engines, developed more than 100 years ago, were the first of the fossil fuel-driven distributed generation (DG) technologies. Reciprocating engines can be found in applications ranging from fractional horsepower units to 60-megawatt (MW) base load electric power plants.

The engine cooling water and exhaust heat from reciprocating engines can be recovered in heat exchangers and used to provide heat for digester heating and/or facility hot water heating. Several lean burn reciprocating engine suppliers have new generation, high efficiency, and low emission units available for use with biogas including Cummins, Caterpillar (MWM), and GE/Jenbacher. These new engines have efficiencies of approximately 40 percent, which stays nearly constant throughout the typical operating range of 50-100 percent engine load. These engines typically convert approximately 40 percent (as a percentage of fuel input energy) to electrical output and 40-45 percent to heat using recovered energy from the engine cooling water and exhaust heat. The total overall efficiency of these reciprocating engines is approximately 80-85 percent. The engines are lean-burn, spark-ignited, low emission gas engines and have digester gas burning experience. All can be fitted with exhaust after-treatment equipment to control NOx and CO emissions to current and future required levels if required. In addition, the existing engines are relatively new Waukesha low emission engine generators. These engines are < 35% efficient as they are a slightly older generation engine and do not have as sophisticated of control systems. They too can be equipped with exhaust after-treatment equipment to meet current/future emission requirements.

Two alternatives were identified using reciprocating engine technology for each process configuration; the first, continuing to utilize the existing engine generators and the second, utilize a new GE/Jenbacher engine generator unit.

3.2 Microturbine

Microturbines are essentially small gas turbines operating at very high rpm to produce power and heat.

Microturbines are extremely low emission technologies and typically do not require an air permit for operation.

Microturbines evaluated typically convert 29 percent to electrical output (as a percentage of fuel input energy) and 29 percent to recoverable exhaust heat for a total overall efficiency of approximately 58 percent.

There are currently several commercial manufacturers offering microturbine power generating units. Only two of these units (FlexEnergy formally known as Ingersoll Rand and Capstone) have experience utilizing digester gas as a fuel source. FlexEnergy offers 250 kW modular units. The Capstone units come in 30, 65, and multiples of 200 kW sizes.

Ingersoll Rand and Capstone have shipped worldwide more than 100 units operating on both natural gas and digester gas. Several dozens of 30 kW and 70 kW units and two 250 kW units are operating on digester gas. Two 250 kW units are in operation on a medium BTU gas at a Oil/Gas Producer in Grand Isle, LA and eight 250 kW units have recently been sold for operation on a medium BTU gas in both the United States and China.

One alternative was identified for each of the process configurations utilizing new Flex Energy microturbine units.

3.3 Fuel Cells

Fuel cells utilize the hydrogen present in the methane-rich digester gas as a fuel source in an electrochemical process. The process converts the elemental carbon and hydrogen from the methane into carbon dioxide and hydrogen and in the process releases electrons, which are captured as direct current (DC) electricity.

The fuel cells evaluated typically convert, as a percentage of fuel input power, 47 percent to electrical output, and 22 percent to recoverable exhaust heat for a total overall efficiency of approximately 69 percent.

Two manufacturers currently offer fuel cells for large-scale power generation, United Technologies Corporation (UTC) and Fuel Cell Energy (FCE). Both manufacturers have provided fuel cells for applications utilizing digester gas; however, only FCE has units currently in operation. Many of these units operating on biogas are located in California. FCE utilizes a more efficient fuel cell technology than UTC, providing 47 percent fuel-to-

electricity efficiency versus UTC's 37-40 percent. Due to the higher efficiencies and additional experience utilizing digester gas, only FCE units are considered for this evaluation.

As an electrochemical process, fuel cells produce significantly less pollutant byproducts than combustion technologies. Fuel cells have approximately 1/100th the emissions generated by engine-generators.

One alternative was identified for each of the process configurations utilizing a new Fuel Cell Energy fuel cell.

3.4 Alternative Benefit Comparison

A summary of the advantages and disadvantages for the existing cogeneration system and three technology alternatives is included in Table 5.

Table 5 Alternative Benefit Comparison
Cogeneration Assessment
SLCDPU

Alternative	Advantages	Disadvantages
Alternatives 1, 2, & 3 - Existing Cogeneration System	• No change in operation	• Does not take advantage of all the digester gas available onsite or reduce facility carbon footprint
Alternative 4 - Conventional Reciprocating Engines	• Proven technology utilizing biogas for over 40 years • Newer generation engines have very high efficiency • Newer engines can easily meet new strict emission regulations	• Requires dedicated building for sound and weather protection • Frequent operator attention required for operations and maintenance • Requires fuel treatment
Alternative 5 - Microturbine	• Ultra low emissions • Simplified electrical interconnection • Low operator attention for operations and maintenance	• Very lowest electrical efficiency • Requires extensive fuel treatment
Alternative 6 - Fuel Cell Generator Unit	• Ultra Low emissions • Highest efficiency • Simplified electrical interconnection • Low operator attention for operations and maintenance	• Highest O&M costs • Highest capital costs • Requires extremely reliable and robust fuel treatment

4.0 FUNDING SOURCES

The following section outlines funding sources that may be available to SLCDPU to implement potential cogeneration alternatives. Table 6 summarizes applicable programs, depending upon how project procurement/development proceeds.

The applicability of the programs noted in Table 6 depends on many factors including procurement method and ownership and the technology utilized. Some of the programs are grants, some credits, and some loans - choosing the correct combination depends on many factors specific to the project.

Table 6 Funding Summary
Cogeneration Assessment
SLCDPU

Program	Source	Summary
Renewable Energy Production Incentive (REPI)	US DOE	Provides financial incentive payments of 1.5 cents per kWh of electricity produced for sale from renewable sources.
Renewable Electricity Production Tax Credit	US Govt.	Provides a 0.9 cents/kWh corporate tax credit for renewable energy systems (applicability is in question as digester gas fueled systems are not specifically addressed)
Commercial (non government) loan programs	Various	Various funding and loan programs exist outside of the above listed government sponsored programs. These are listed in the attached documentation and range from equipment secured loans to unsecured loans, to guaranty and subsidized loans
Renewable Energy Credits (RECs)	Various	Renewable energy credits can be sold for power generated utilizing renewable fuels. These energy credits (referred to as tags) are sold on an open market and for digester gas; fueled systems can represent income of approximately \$0.0015/kWh. This amount varies with the market, which varies by area in the Country and type of technology utilized.
Clean Renewable Energy Bonds (CREBs)	Various	Various sources of bond financing exist which provide low/no interest financing to municipal entities for renewable energy projects. These allow municipal entities to take advantage of tax credits even though they cannot do so directly. Typically, fees of upwards of 5% of the bond funding proceeds apply for these bond funds.

4.1 Renewable Energy Credits

Renewable energy credits are a mechanism by which energy generated by renewable means can be valued and traded. Users who desire to "purchase" renewable power can purchase renewable energy credits for a certain amount of power that they will utilize.

Entities generating renewable power can get credit for this power (beyond the value of the power) on a $/kWh basis to the grid. The renewable energy credit is a means in which to track power, which has been generated, from renewable sources.

Renewable energy credits can be sold for power generated from renewable fuels. These energy credits (referred to as tags) are sold on an open market. This amount varies with the market, and is dependent upon area of the country and type of technology utilized. While the value is significantly less than newly generated power, even “tags” for power generated in past periods can be sold.

Typically, “tags” are sold through a broker specializing in these credits.

SLCDPU should pursue sale of “tags” for all of the power generated from the cogeneration system.

5.0 LIFE CYCLE COST EVALUATION RESULTS

To evaluate the benefits and costs of these alternatives, both the projected capital costs of the installation and the yearly operations and maintenance (O&M) costs were calculated. The evaluation takes into account the value of, or purchase of electrical power. The method selected for this analysis was to determine the total present worth of the project. Each alternative was then compared. Assumptions used for the life cycle cost analysis are shown in Table 7.

The results of the life cycle cost analysis are presented in Tables 8 and 9 for the current and BNR process digester gas projections.

Total project capital costs, including design and construction costs, for each alternative were estimated. Capital and life cycle costs are presented in Appendix B and C, respectively

5.1 Greenhouse Gas Emissions

The Environmental Protection Agency (EPA) has proposed a mandatory monitoring and reporting rule, for facilities that emit greenhouse gases (GHG) of more than 25,000 metric tons of CO_2 equivalent per year. The greenhouse gases include carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), and fluorinated gases. The proposed rule does not affect wastewater treatment process emissions, but does cover onsite combustion sources. Table 10 summarizes the greenhouse gas emissions for each alternative. The GHG emissions are shown for the best-case gas production as a conservative measurement of emissions because more digester gas will be burned onsite. The onsite combustion emissions are the emissions that qualify for the EPA proposed rule. The GHG emissions for all alternatives are below the 25,000 metric ton per year minimum and the SLCDPU will not have to report their emissions. The total GHG emissions include both the emissions from onsite combustion and the electricity purchased offsite. Additionally, the use of the existing

engines was considered with and without natural gas supplementation. A review of all alternatives without natural gas usage is provided in Appendix D.

5.2 Qualitative Summary

Table 11 ranks the cogeneration alternatives utilizing weighted economic and non-economic criteria.

Table 7 Criteria and Financial Assumptions Cogeneration Assessment SLCDPU

Present worth year	2015
First year of evaluation	2016
Project duration, years	20
Inflation (capital costs)	1.80%
Inflation (fuel and electricity costs)	2.85%
Inflation (O&M costs)	1.80%
Gross discount rate	5.00%
Digester Gas LHV, Btu/scf	560
Existing engine availability percentage	90%
New engine availability percentage	90%
New microturbine availability percentage	95%
New fuel cell availability percentage	98%
O&M rate for existing engines alternatives $/kWh	$0.020
O&M rate for new engine alternatives $/kWh	$0.010
O&M rate for new microturbine alternatives $/kWh	$0.025
O&M rate for new fuel cell alternatives $/kWh	$0.037
O&M rate for fuel treatment system $/kWh	$0.010

Table 8 Life Cycle Cost Analysis – Current Process Configuration
Cogeneration Assessment
SLCDPU

Project Alternative	Description	Estimated Project Cost(1) ($ Million)	Total Present Worth of Costs(2,3) ($ Million)	Total PW of Net Benefit Compared to Existing Cogeneration ($ Million)
1	Existing Cogeneration – Run 1 Engine	0	8.3	-0.8
2	Existing Cogeneration – Run 2 Engines w/o NG purchase	0	7.5	-
3	Existing Cogeneration – Run 2 Engines w/ NG purchase	0	8.4	-0.9
4	New 1400 kW Engine	9.4	14.9	-7.4
5	New 1000 kW Microturbine	6.7	15.2	-7.7
6	New 1400 kW Fuel Cell	12.1	20.9	-13.4

Notes:
(1) This includes estimated construction cost plus associated costs for engineering, administration, and construction management.
(2) This includes overall treatment plant energy and O&M costs for each individual alternative.
(3) This does not include future potential regulatory surcharges based on future greenhouse gas and emission regulations.

Table 9 Life Cycle Cost Analysis – BNR Process Configuration
Cogeneration Assessment
SLCDPU

Project Alternative	Description	Estimated Project Cost[1] ($ Million)	Total Present Worth of Costs[2,3] ($ Million)	Total PW of Net Benefit Compared to Existing Cogeneration ($ Million)
1	Existing Cogeneration – Run 1 Engine	0	10.1	-
2	Existing Cogeneration – Run 2 Engines w/o NG purchase	N/A[4]	N/A[4]	N/A[4]
3	Existing Cogeneration – Run 2 Engines w/ NG purchase	0	12.7	-2.6
4	New 850 kW Engine	8.6	17.3	-7.2
5	New 666 kW Microturbine	5.3	15.9	-5.8
6	New 900 kW Fuel Cell	10.7	22.2	-12.1

Notes:
(1) This includes estimated construction cost plus and associated costs for engineering, administration, and construction management.
(2) This includes overall treatment plant energy and O&M costs for each individual alternative.
(3) This does not include future potential regulatory surcharges based on future greenhouse gas and emission regulations.
(4) Alternative 2 not viable as insufficient digester gas to run both existing engines without natural gas purchase

Table 10 Greenhouse Gas Emissions Cogeneration Assessment SLCDPU

Project Alternative	Current		BNR	
	GHG Emissions from Onsite Combustion(1), CO_2 Equivalent value (metric-ton/year)	Total GHG Emissions(2), CO_2 Equivalent value (metric ton/year)	GHG Emissions from Onsite Combustion(1), CO_2 Equivalent value (metric-ton/year)	Total GHG Emissions(2), CO_2 Equivalent value (metric ton/year)
Existing Cogeneration (1 Engine w/o NG)	5,200	8,700	3,800	9,000
Existing Cogeneration (2 Engines w/o NG)	5,100	7,000	N/A	N/A
Existing Cogeneration (2 Engines w/ NG)	5,800	7,100	5,900	8,500
New Engine	5,100	5,900	4,400	8,900
New Microturbines	5,100	7,800	6,000	11,400
New Fuel Cells	7,500	7,800	8,500	12,400

Notes:

(1) CO_2 equivalent emissions from CH_4, CO_2, and N_2O produced onsite from combustion of digester gas and natural gas through cogeneration or by flaring the gas.

(2) CO_2 equivalent emissions from CH_4, CO_2, and N_2O produced from onsite combustion and the emissions produced from electricity generation by Rocky Mountain Power.

Table 11 Cogeneration Study Alternatives - Rating Matrix
Cogeneration Assessment
SLCDPU

Ranking Criteria		Present Worth of Life Cycle Cost[(3)]	Energy/Green-house Gas Regulations	Protection Against Energy Price Volatility	Reliability/ Redundancy	O&M Complexity	Length of Permit Application Process	Proven Biogas Cogeneration Technology	Footprint	Efficient Use of Resources	Total Weighted Score[(1)]
Weighting Factor[(2)]		5	5	3	4	4	3	3	3	5	–
Project Alternative	Description										
1	Existing Cogeneration (1 w/o NG)	4	2	4	5	4	5	5	4	4	140
2	Existing Cogeneration (2 w/o NG)	4	2	4	4	4	4	5	4	3	128
3	Existing Cogeneration (2 w/ NG)	3	2	3	4	4	4	5	4	5	130
4	New Engines	2	4	4	4	5	3	4	4	3	126
5	New Microturbine	1	2	2	4	3	4	3	3	2	89
6	New Fuel Cell	1	4	3	3	2	4	2	2	3	93

Notes:
(1) Total Weighted Score equals the sum of each criteria's weighted factor multiplied by its individual ranking for each respective alternative; highest value is most desirable/beneficial, lowest value is least desirable/beneficial.
(2) Weighting Factors: 5 - More Important, 1 - Less Important.
(3) Present worth of life cycle costs are based on the worst case digester gas projection as shown in Table 8 for Current Process Configuration.

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6.0 RECOMMENDATIONS

The recommendation of this cogeneration assessment for SLCDPU is to continue to use the existing engines with either the current treatment process or a new BNR process. New equipment reduces emissions and increases efficiency but results in higher life cycle costs.

Additional recommendations include the following:

- Renegotiate the terms of the contract with the power utility to allow for export of excess power. This would allow for operation of both existing engines and reduce the quantity of flared digester gas.
- Consider a fats, oils and grease (FOG) collection program in the city and add this waste to the digesters, which currently have spare capacity. FOG collection programs in other locations have led to increase in digester gas production of 25-50 percent.
- An alternative outside the scope of this study that could be considered is using digester gas for fleet vehicles.

Note:

A complete copy of Carollo Engineers' report Appendices A-D, is included in the Phase II Technical Memorandum dated December 14, 2014.

Appendix C

Phase II Scoring and Ranking Matrix

Salt Lake City Renewable Energy Plan
Detailed Site Evaluation and Project Ranking

Category			Site						Interconnection		Zoning	Permitting	Generation				Sustainability						Weighted Average Scoring
Weight			30%						15%		15%	10%	20%				10%						
Criteria			Compatibility with existing site use	Infrastructure	Site access	Physical Characteristics	Public safety	Public Nuisance	Access	Ease of interconnection	Local Zoning Standards	Local State Federal	Resource Quality	Power Resiliency and reliability	Electricity Supply	Electricity End Use	Renewable Energy	Energy sustainability	Climate Change	Leadership and Education	Economic Development	Public Policy	
Description			Ability to integrate renewable energy project with existing DPU site use	Extent to which project can be constructed with existing infrastructure at the site.	Site access for construction and , interconnection activities	Are there obvious physical site constraints, e.g. topographical, geologic, property line encroachment, proximity to scenic, recreation or environmentally sensitive areas?	Does project location create a potential safety risk to the public?	Does proximity of the project to residences or other established uses in the vicinity pose a potential public nuisance (visual, degradation of property value, noise etc.	Extent to which project site provides either direct access to DPU load or the distribution system.	Complexity and costs of meeting distribution system interconnection requirements including costs of studies and complexity and costs of additional equipment required for interconnection	Extent to which renewable energy project is compatible with existing zoning ordinances.	Permitting Requirements and Complexity	Quality of RE resource at the site	Will the project increase DPU energy system resiliency to power outages and reliability of the delivery of DPU services?	Extent to which ptential RE project will serve load at the project site	How is the project likely to contribute to offsetting DPU's largest and most critical end use loads?	Will this project contribute to meeting SLC's renewable energy goals?	Extent this project will contribute to reducing reliance on fossil generated electricity and demonstrate efficient use of energy	Extent to which project will contribute to meeting SLC's GHG goals.	Will this project enhance opportunities to educate SLC citizens and improve public perception of DPU and the City's commitment to clean energy and air?	Potential to enhance opportunities for local clean energy vendors and jobs.	Will this project demonstrate leadership (leading by example) or remove regulatory or policy barriers that will lead to an increase in the deployment of distributed renewable energy systems in SLC	
Weight			20%	15%	15%	15%	15%	20%	50%	50%	100%	100%	25%	25%	25%	25%	20%	20%	10%	15%	15%	20%	
Project Site																							
Project No. 1	Mountain Dell Dam	Hydroelectric	2	2	2	3	5	5	5	3	5	5	5	0	5	5	5	5	5	4	3	5	4.0150
Project No. 2	Terminal Park Reservoir	Roof Mount PV	5	4	5	4	5	5	5	3	1	1	5	0	5	1	5	3	3	5	5	5	3.2500
Project No. 3	Morris Reservoir	Roof Mount PV	5	2	5	4	4	3	5	3	1	4	5	0	3	5	5	3	4	4	3	5	3.3600
Project No. 4	South Lift	Ground Mount PV	5	3	5	5	3	4	5	3	5	5	5	0	3	5	5	3	4	4	3	5	4.1650
Project No. 5	15th East Reservoir	Roof Mount PV	5	5	4	3	5	4	5	3	5	5	5	0	3	5	4	4	5	5	4	4	4.2300
Project No. 6	B35-R18	Microhydro	2	2	1	2	3	5	3	3	4	5	2	0	0	0	5	0	0	1	3	5	2.6900
Project No. 7	B11-R13	Microhydro	2	2	3	3	5	5	3	3	4	5	2	0	0	0	5	0	0	1	3	5	2.9150
Project No. 8	C41-R20	Microhydro	2	2	1	2	3	5	3	3	4	5	2	0	0	0	5	0	0	1	3	5	2.6900
Project No. 9	Victory Rd Reservoir	Roof Mount PV	5	5	2	3	5	5	5	3	1	3	5	0	2	5	5	3	4	3	3	5	3.3150
Project No. 10	Concord Lift	Ground Mount PV	5	3	2	2	2	2	5	3	0	3	1	0	3	5	5	3	4	3	2	4	2.5300
Project No. 11	Baskin Rreservoir	Roof Mount PV	4	2	5	1	5	5	2	2	1	5	5	0	3	5	5	3	4	3	4	5	3.1300
Project No. 12	Wilson Reservoir	Roof Mount PV	5	4	2	4	3	2	5	3	5	2	5	0	3	5	5	3	4	3	3	5	3.5950
Project No. 13	6200 S. Well	Ground Mount PV	5	4	4	3	3	5	5	4	3	4	1	0	1	5	5	2	3	3	2	4	3.4300
Project No. 14	D74-DV-1	Microhydro	2	1	5	3	3	5	1	1	5	5	3	0	0	0	5	0	0	1	3	5	2.7700
Project No. 15	Greenfield Village Well	Ground Mount PV	5	4	5	3	4	5	3	1	5	1	5	0	1	5	5	3	3	2	3	4	3.3650
Project No. 16	Sorenson Fitness Center	Roof Mount PV	5	4	5	5	5	5	5	4	5	5	5	0	3	3	3	3	3	4	4	4	4.2800
Project No. 17	SLC DPU Building	Roof Mount PV	5	4	5	5	5	4	5	4	5	5	5	0	4	3	3	3	3	4	4	4	4.2700
Project No. 18	SLCWRF Cogeneration	Biogas	5	5	5	5	5	5	5	5	5	5	5	0	5	5	5	3	3	4	3	5	4.6450
Project No. 19	500 South Trunlkine	Waste Heat Recovery	5	2	3	2	5	5	5	3	5	5	5	0	3	5	4	3	4	4	3	5	4.0250

Appendix D

Rate Schedule and Financing Primer
Utah Clean Energy

Utah Clean Energy

Rate Schedule and Financing Primer

Salt Lake City Renewable Energy Plan

Sophie Hayes and Kate Bowman
November 1, 2014

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Appendix A: Summary of Available Rate Structures:

Electric Service Schedule 31: Partial Requirements Service – Large General Service – 1,000 kW and Over

Schedule 31 provides supplementary, backup and maintenance power to customers who obtain any part of their regular electric requirements from self-generation. This schedule is for customers who would otherwise qualify for Schedules 8 or 9 and who have on-site generation capacity between 1,000 kW and 15,000 kW.

This rate schedule was designed such that large "partial requirements" customers compensate the utility for being ready to serve as a "backup generator" during planned or unplanned outages and for supplementary power and energy not served by onsite generation. Under this tariff, customers contract with the Company for a specified amount of both supplementary power and backup power, which the Company agrees to have available for delivery to the customer.

All energy consumed under Schedule 31 is billed based on the pricing outlined in the customer's general service schedule (Schedule 8 or 9). Power charges are determined based on the amount of supplementary power and backup power contracted for. Supplementary power is billed based on the power charges specified in the customer's general service schedule. The power charge for backup power is based on the 15-minute period of highest on-peak usage. Backup power charges are reduced by half during scheduled maintenance, and there is no charge for off-peak backup power. Backup power is subject to a facilities charge, based on voltage. Any power above and beyond the total contracted power is considered Excess Power. Customers on this rate schedule also pay a monthly customer charge.

Although this rate schedule could be used to supply supplementary and backup power to a facility with on-site generation from renewables, it would only be practical if the customer's generation were to track usage closely (or if usage could be scheduled to track generation). Schedule 31 anticipates that customers will be reducing or eliminating their usage of Company power the majority of the time and does not provide credits for electricity production in excess of usage, nor does it allow for resale of excess electricity; however, a facility taking service under Schedule 31 may still qualify as a "Qualifying Facility" (see below) and sell excess electricity back to the utility at wholesale "avoided costs" rates.

Full text of Schedule 31:
https://www.rockymountainpower.net/content/dam/rocky_mountain_power/doc/About_Us/Rates_and_Regulation/Utah/Approved_Tariffs/Rate_Schedules/Partial_Requirements_Service_Large_General_Service_1_000_kW_and_Over.pdf

Electric Service Schedule 32: Service from Renewable Energy Facilities

Schedule 32 was enabled by Senate Bill 12 (SB12), passed during the 2012 legislative session, but has not yet been finalized or approved by the Public Service Commission. This tariff is designed to serve large customers who would like to source a larger portion of their electric service from renewable energy resources than is currently available through the Company's resource portfolio. Using Schedule 32, large customers will be able to build or purchase energy from off-site renewable energy projects and pay Rocky Mountain Power for the delivery of such electricity to their facilities. Whether the renewable facility is owned by the customer or a third party, the customer and the renewable energy facility pay all of the costs and bear all of the risk of the renewable energy facility, and the facility is also responsible for all interconnection and integration costs. The customer must contract for more than 2. 0 MW of electricity delivery through Schedule 32.

As between a renewable energy facility and a Schedule 32 customer, electricity delivery is facilitated by two matching contracts: the Rocky Mountain Power will contract with the owner of the renewable energy facility to purchase electricity for resale to the customer (or in some cases more than one customer). Rocky Mountain Power will then sell that electricity to the customer or customers under renewable energy contracts with the same duration and pricing as the contract between the company and the owner of the renewable energy facility. Customers who want to develop their own renewable energy facilities may also contract for the delivery of electricity from their own off-site renewable projects through this tariff. Schedule 32 does not replicate virtual net metering and does not allow net metering.

This tariff is not yet finalized, however Utah Clean Energy will be able to provide additional recommendations regarding the utility of this tariff when it is finalized.

Full text of Senate Bill 12: http://le.utah.gov/~2012/htmdoc/sbillhtm/SB0012S01.htm

PURPA & Qualifying Facilities

The Public Utilities Regulatory Policy Act (PURPA) was passed in 1978 to promote greater use of domestic energy and renewable energy. PURPA established the “Qualifying Facility” (QF) class of electricity generating facilities to receive special rate and regulatory treatment, in the interest of promoting their development. QFs fall into two categories:

- Small Power Production Facilities, which are facilities of 80 MW or less whose primary energy source is renewable, including solar, hydro, wind, geothermal, or biomass resources.

- Cogeneration Facilities, which sequentially produce electricity and thermal energy (such as steam or heat) in a way that is more efficient than producing each independently.

One provision of PURPA requires that monopoly utilities purchase power from Qualifying Facilities that are able to provide electricity at rates equivalent to the utility's own "avoided cost." Avoided cost is defined as the incremental cost to an electric utility of electric energy or capacity, which, but for the purchase from the QF, the utility would have to generate itself or purchase from another source.

An owner or operator of a generating facility with a maximum net power production capacity of greater than 1 MW (1,000 kW) may obtain QF status by submitting a "self-certification" (no fee) or by applying for and obtaining Federal Energy Regulatory Commission (FERC) certification of QF status (fee required). To obtain QF status, facilities must file an electronic form through the FERC website. Facilities smaller than 1 MW do not need to certify in order to qualify as QFs.

Pursuant to PURPA, FERC adopted regulations relating to purchases and sales of electricity to and from QFs. These regulations afford state utility commissions wide latitude in setting avoided cost prices and procedures for purchases from QFs. In Utah, the Public Service Commission has approved two electric service schedules (Schedules 37 and 38) for implementing PURPA and FERC regulations.

Electric Service Schedule 37: Avoided Cost Purchases from Qualifying Facilities

Schedule 37 is available to owners of small QFs: either cogeneration facilities with a design capacity of one MW or less or Small Power Production Facilities with capacity of three MW or less. Avoided cost rates under Schedule 37 are published, "standard offer" rates. QFs enter into a written power sales contract with Rocky Mountain Power based on these published prices.

There is a cumulative cap of 25 MW of capacity for new resources contracted under this schedule before Rocky Mountain Power must update Schedule 37 rates. However, the Commission requires that Rocky Mountain Power update Schedule 37 rates once a year, so the 25 MW cap is effectively an annual cap.

Schedule 37 rates are published as non-levelized annual rates (winter on- and off-peak and summer on- and off-peak rates) or as 20 –year nominal (present value) levelized prices in cents per kWh. Current levelized prices for baseload and solar facilities are the following:

Levelized Prices (Nominal) for baseload (cogeneration) resources in cents per kWh:

On-Peak Energy Prices		Off-Peak Energy Prices	
Winter	Summer	Winter	Summer
4.589	4.819	3.859	4.089

Levelized Prices (Nominal) for fixed tilt solar resources in cents per kWh:

On-Peak Energy Prices		Off-Peak Energy Prices	
Winter	Summer	Winter	Summer
4.013	4.246	3.548	3.781

Levelized Prices (Nominal) for tracking solar resources in cents per kWh:

On-Peak Energy Prices		Off-Peak Energy Prices	
Winter	Summer	Winter	Summer
4.188	4.420	3.613	3.846

Full Text of Schedule 37: https://www.rockymountainpower.net/content/dam/rocky_mountain_power/doc/About_Us/Rates_and_Regulation/Utah/Approved_Tariffs/Rate_Schedules/Avoided_Cost_Purchases_from_Qualifying_Facilities.pdf

Electric Service Schedule 38: Qualifying Facility Procedures

Schedule 38 is available to owners of cogeneration QFs with capacity greater than one MW or renewable QFs with capacity greater than three MW, and can be used to make electricity sales to Rocky Mountain Power. Pricing under this schedule is not published; rather the Commission approved a pricing calculation method that Rocky Mountain Power uses to establish “indicative prices.” Large QFs negotiate pricing and contract terms directly with Rocky Mountain Power based on the supply characteristics of the QF and the utility resources it will displace.

Full text of Schedule 38:
https://www.rockymountainpower.net/content/dam/rocky_mountain_power/doc/About_Us/Rates_and_Regulation/Utah/Approved_Tariffs/Rate_Schedules/Qualifying_Facility_Procedures.pdf

Schedule 135: Net Metering

Net metering allows customers with on-site renewable energy facilities to connect to the electrical grid and receive credit for excess electricity that is produced, but not consumed, on-site. A “net meter” replaces the standard electrical meter and measures both the electricity supplied by the Company and the electricity which is generated by the customer and fed back to the electric grid. Electricity produced by the generating facility is first consumed onsite, but if the customer is not consuming electricity at the time it is being generated, excess electricity is sent back out to the electrical grid. The customer is billed for their ‘net usage’ over the course of a monthly billing period: the electricity supplied by the utility, minus the electricity supplied by the customer. Facilities which are eligible for net metering must use energy derived from one of the following to generate electricity:

- solar photovoltaic and solar thermal energy
- wind energy
- hydrogen
- organic waste
- hydroelectric energy
- waste gas and waste heat capture or recovery
- biomass and biomass byproducts, except for the combustion of
  - wood that has been treated with chemical preservatives such as creosote, pentachlorophenol, or chromated copper arsenate
  - municipal waste in a solid form
- forest or rangeland woody debris from harvesting or thinning conducted to improve forest or rangeland ecological health and to reduce wildfire risk
- agricultural residues
- dedicated energy crops
- landfill gas or biogas produced from organic matter, wastewater, anaerobic digesters, or municipal solid waste
- geothermal energy

Schedule 135 requires that generating facilities be located on or adjacent to the customer’s premises, and are intended primarily to offset part or all of the customer’s own electrical requirements. The customer-generator can aggregate its electrical requirements from multiple meters for the purpose of net metering, as long as all meters are located at or adjacent to the same property. Non-residential facilities can be up to 2 MW, although Schedule 135 is structured to encourage generating facilities to be sized such that average annual generation does not exceed average annual onsite load. Compensation for excess electricity production depends on whether a facility is considered a “small non-residential customer” or “large non-residential customer:”

- Small non-residential customers (who are otherwise billed under Schedule 15 or Schedule 23) are credited for excess electricity production with a cumulative kilowatt-hour credit. The credit will be deducted from the customer's kilowatt-hour usage on their next monthly bill, offsetting the customer's next monthly bill at the full retail rate of the customer's rate schedule. These credits roll over month-to-month until the customer's March billing period, after which remaining credits expire.
- Large non-residential customers (who are otherwise billed under Schedule 6, 6A, 6B, Schedule 8, or Schedule 10) are billed for their net electricity usage each month. In the event that generation exceeds usage in a given month, these customers can choose to receive credit for this excess electricity production one of three ways:

(1) Receive an average energy price per kilowatt-hour based on volumetric non-levelized energy prices in Schedule 37, using the following formula:

  0.38 x Winter On-Peak Energy Price
+ 0.19 x Summer On-Peak Energy Price
+ 0.29 x Winter Off-Peak Energy Price
<u>+ 0.14 x Summer Off-Peak Energy Price</u>
= total compensation for excess electricity production

(2) Receive a seasonally differentiated energy price based on non-levelized energy prices in Schedule 37, using the following formula:

Summer months (June – September):

  0.57 x Summer On-Peak Energy Price
<u>+ 0.43 x Summer Off-Peak Energy Price</u>
= compensation for excess electricity production from Jun – Sep

Winter months (October – May):

  0.57 x Winter On-Peak Energy Price
<u>+ 0.43 x Winter Off-Peak Energy Price</u>
= compensation for excess electricity production from Oct - May

(3) An average retail rate for the Electric Service Schedule applicable to the net metering customer as calculated from the previous year's Federal Energy Regulation Commission Form No. 1. Average retail rates from the most recently filed tariff (. effective September 2014) are the following:

Schedule 6: 8.2075¢ per kWh
Schedule 6A: 11.2772¢ per kWh
Schedule 6B: 8.5765¢ per kWh
Schedule 8: 7.2585¢ per kWh
Schedule 10: 7.1794¢ per kWh

The Utah Legislature originally required that electrical corporations offer net metering to their customers in 2002, through House Bill 0007. Utah's net metering law has since been modified several times, most recently during the 2014 legislative session through Senate Bill 208. Recent modifications to net metering legislation, in Utah and across the United States, have focused on the potential that net metering rate schedules do not adequately account for the costs and benefits of net metering customers and allow for cross-subsidization amongst ratepayers. Senate Bill 208 (2014) directed the Utah Public Service Commission (PSC) to determine whether costs incurred from a net metering program will exceed the benefits of the net metering program or vice versa, and to determine a just and reasonable charge, credit or ratemaking structure in light of the costs and benefits.

Rocky Mountain Power's net metering program is currently available to any customer who owns or leases a renewable generating facility, and capacity for the program is capped at 20% of the Company's 2007 peak demand. According to Rocky Mountain Power's 2014 Net Metering Customer Generation Report, only two percent of this capacity has been filled. Changes to the net metering tariff and Schedule 135 may have an impact on its value to self-generation customers in the future; however in its current form, Schedule 135 is the recommended tariff for customers with renewable generation who meet the net metering qualifications.

Full text of Schedule 135:
https://www.rockymountainpower.net/content/dam/rocky_mountain_power/doc/About_Us/Rates_and_Regulation/Utah/Approved_Tariffs/Rate_Schedules/Net_Metering_Service.pdf

Virtual Net Metering:

Virtual net metering allows parties to receive credit or compensation for generation from offsite renewable energy facilities. Similarly, a structure often known as "community net metering" can allow multiple parties to purchase shares of the output from a single renewable facility that is not physically connected to their property (or their meter). Virtual net metering and community net meting models allow individuals who are not good candidates for distributed solar (due to shading, or because they are renting their home or live in an apartment) to source electricity from renewable generation. Virtual net metering is not

currently authorized in Utah statute, and enabling a virtual net metering policy which allows kilowatt-hour per kilowatt-hour credits from an offsite solar facility to offset a customer's energy bill would require legislative action. Sixteen states and the District of Columbia have authorized some form of virtual net metering, although policies vary widely from state to state. Some variations simply authorize virtual net metering as an option that utilities may choose (but are not required) to offer, or restrict the policy to certain entities, certain utility service areas, or certain geographic areas. [1]

Utah's existing net metering statute has been the subject of heated debate in the last few months; recent modifications to net metering legislation, in Utah and across the United States, have focused on the potential that net metering rate schedules do not adequately account for the costs and benefits of net metering customers and thus allow for cross-subsidization amongst ratepayers. The Public Service Commission has launched a new docket, *14-035-114,* to investigate the costs and benefits of residential net metering, specifically. No previous docket has thoroughly investigated both the costs *and* the benefits of net metering, and the findings of Docket 14-035-114 will have an impact on the future of virtual net metering in Utah.

A few case studies of virtual net metering programs in other states provide examples of potential uses here in Utah:

Clean Energy Collective:

Clean Energy Collective (CEC) is a private company that funds, builds, and maintains medium-scale clean power facilities that are collectively owned by participating utility customers. Often referred to as "community solar" arrays, CEC projects can range from 500 kW to 50 MW in size and are sited in an ideal location and interconnected to the local utility's grid. CEC has 33 existing or ongoing projects, in 6 states (CO, MA, MN, NM, VT, WI) and 13 utility service territories. Although many of the utilities participating in CEC-built solar arrays are municipal or customer-owned co-operative utilities, several large investor-owned utilities have worked with CEC to develop solar projects, including National Grid (3 projects of 1 MW each in Massachusetts), NSTAR (2 projects of 1 MW each in Massachusetts), the Western

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[1]For a more in depth discussion of the types virtual net metering policies by state, see the following reports:
National Conference of State Legislatures, "Net Metering: Policy Overview and State Legislative Updates." <http://www.ncsl.org/research/energy/net-metering-policy-overview-and-state-legislative-updates.aspx>.
Institute for Local Self-Reliance, "Virtual Net Metering." <http://www.ilsr.org/virtual-net-metering/>.
ICLEI, "Aggregate Net Metering: Opportunities for Local Governments." <http://www.icleiusa.org/action-center/aggregate-net-metering-opportunities-for-local-governments>.

Massachusetts Electric Company (2 projects of 1 MW each in Massachusetts), and Xcel Energy (11 projects totaling just over 5 MW in Colorado).

Participating customers can purchase one or more panels in the array and receive compensation for the electricity produced by their solar panels. CEC claims to have superseded the constraints of net metering laws through partnerships with utilities and by using billing software that doesn't require legislation to distribute on-bill credits to customers. Instead, the electricity generated from the panels is sold directly to the utility through a mutually agreed contract (such as a Power Purchase Agreement or a Feed-in Tariff). The customer receives a portion of the monetary payment for the electricity, based on the panels they have purchased, via an on-bill credit. CEC uses a proprietary RemoteMeter™ system to calculate monthly bill credits for members in a way that integrates with utilities' existing billing system.

Connecticut and Virtual Net Metering

Connecticut has made virtual net metering available exclusively to state, municipal, and agricultural customers, who may host virtual net metering facilities and credit the generation towards their own accounts as well as other authorized accounts[2]. A virtual net metering facility can be up to 3 MW and must generate electricity using either renewable resources or combined heat and power. The virtual net metering facility can be owned by the host (a state, municipal, or agricultural customer), leased by the host, or owned by a third party and located on the host's property.

Virtual net metering hosts may aggregate all of the meters they own and receive credits towards their own accounts for electricity generated at the facility, and may also credit the electricity generated by the facility towards 'beneficial accounts' as long as they are within the same distribution company's service territory. A municipal or state customer can host up to 5 additional municipal or state accounts and 5 additional non-state or -municipal buildings if those accounts are critical facilities (including hospitals, police stations, fire stations, water treatment plants, sewage treatment plants, and public shelters) and connected to a micro grid. An agricultural customer can host up to 10 beneficial accounts as long as those accounts either use electricity for agricultural purposes, or are municipal or noncommercial critical facilities. When host customers produce more electricity than they consume, the excess electricity is credited to these beneficial accounts.

[2] More information from DSIRE: http://dsireusa.org/incentives/incentive.cfm?Incentive_Code=CT01R&re=0&ee=0.

Appendix B: Summary of Available Financing Options:

Utah Solar Incentive Program

The Utah Solar Incentive Program provides Rocky Mountain Power customers with a rebate for a portion of the initial cost of installing a solar photovoltaic system. Rocky Mountain Power administers the program, and Rocky Mountain Power customers can apply for the incentive during a two week period in January each year. Incentives are awarded based on a lottery system. The incentive rates and availability differ based on system size and customer class, and incentives decrease each year of the 5-year program. There is a cap on the incentive amount that is available for each category of project each year. For 2015, the available incentives and

Category		Small Non-Residential	Large Non-Residential
System Size*		≤ 25 kW*	> 25 kW ≤ 1,000 kW*
2015	Available Capacity	4,000 kW (AC)	8,500 kW (AC)
	Available Incentive	$0.90/Watt (AC)	$0.70/Watt (AC)
2016	Available Capacity	4,500 kW (AC)	10,000 kW (AC)
	Available Incentive	$0.85/Watt (AC)	$0.65/Watt (AC)

capacity are as follows:

*This does not refer to the maximum allowable size for the photovoltaic installation, but to the maximum amount of capacity which the incentive can be applied to. For example, although commercial installations may be up to 2MW, based on the net metering requirements, only half of a 2 MW system would be eligible to receive the incentive.

Recipients of the incentive must enroll in Rocky Mountain Power's Cool Keeper program, which allows Rocky Mountain Power to coordinate individual air conditioning units, reducing peak energy demand in the summer. Recipients of the incentive must also sign a portion of the Renewable Energy Certificates (RECs)[3] generated by the system over to Rocky Mountain Power, equal to 0.28 MW for each incentivized kW per year for 20 years. This amounts to approximately 20% of the RECs generated by a solar installation, and relinquishing ownership of the RECs may limit the rights to publically advertise an installation as a green power facility. This provision should also be considered carefully for any facility that will be pursuing LEED certifications or other green building certifications. The owner of the solar installation could choose to register the remaining RECs with a certified REC tracking organization (such as WREGIS) in order to sell them through REC broker. In order to prevent 'double-counting' RECS,

[3] The E.P.A. defines RECs as "The property rights to the environmental, social, and other nonpower qualities of renewable electricity generation." < http://www.epa.gov/greenpower/gpmarket/rec.htm>.

any given facility can only be registered once, so the owner of the installation would have to coordinate registration of their facility and divide ownership of the RECs in coordination with Rocky Mountain Power.

While applications for the Utah Solar Incentive Program can be very competitive, particularly within the residential category, the small non-residential category has been under-utilized in past years and presents an opportunity for smaller solar PV installations of less than 25 kW. In 2013, all of the small non-residential projects that applied for the incentive were offered capacity, and the total of these applications still did not reach the cap for the program in 2013. Rocky Mountain Power re-opened the application process in May to accept additional applications for this category. Approximately 1 MW of capacity was not ultimately used, and this capacity carried forward to be used in the future. Once again, in 2014, every small non-residential applicant was offered capacity. The Utah Solar Incentive Program is currently scheduled to run through 2017, and cannot be combined with any other Rocky Mountain Power incentive or grant programs, including Blue Sky Community Grants.

For more information and to apply: https://www.rockymountainpower.net/env/nmcg/usip.html

Blue Sky Community Grants

Rocky Mountain Power's Blue Sky program allows electric customers to choose to pay an additional fee on their bill to support renewable energy. A portion of these fees is used to provide grants for the construction of renewable energy installations (including solar PV, wind, geothermal, hydro, wave energy, and low-emissions biomass) through the Blue Sky Community Project Funds. Rocky Mountain Power accepts applications for Blue Sky Community grants on an annual basis, and any locally-owned, commercial-scale project of 10 MW or less may apply. Funding from the Blue Sky program is awarded considering the "reasonableness of the budget and funding request, the technology, project location, the complexity of the installation, community benefits, potential for public education, project readiness and the ability of the project sponsor to leverage other funding sources." Smaller projects (typically considered to be projects less than 25 kW) must be net metered, and larger projects may make other interconnection agreements with Rocky Mountain Power (although off-grid projects are not eligible.) Applicants may only receive funding through the Blue Sky program once every 3 years, and Blue Sky grants can only fund up to 60% of the total project costs. Although the majority of Blue Sky Community Grant awards have gone to solar projects, a few wind, low-impact hydro, and biomass projects have also received funding through this program.

The application window for 2015 has not been announced, but in 2014 Rocky Mountain Power accepted applications from April 9 to June 30, planned to announce awards by November 30 2014, and required that all projects be completed by December 2015. Blue Sky grants have funded numerous projects in Salt Lake City, including solar installations on churches; educational, arts, or cultural centers; Utah Transit Authority facilities; Salt Lake City School District buildings; and Salt Lake City's Plaza 349 building.

For more information and to apply: https://www.rockymountainpower.net/blueskyfunds

Power Purchase Agreements (PPAs)

A Power Purchase Agreement is a contract between two parties which outlines terms for the sale of electricity from one party to another. Power Purchase Agreements are commonly used as a financing mechanism for solar photovoltaic installations. Typically, a third-party developer builds, owns, and maintains a solar photovoltaic system for a host customer, and the host customer agrees to purchase electricity produced by the solar panels at a fixed price for a predetermined time period. The solar installation may be located on the host customer's roof or property, and many PPAs give the host customer the opportunity to purchase the solar equipment at depreciated rates after a certain time period. PPAs are an advantageous financial arrangement for non-profit organizations, local governments, and other entities who cannot take advantage of tax incentives because they allow the third-party developer to receive the tax benefits of the solar installation and pass the savings on to their host customer.

In 2010, House Bill 145 authorized Power Purchase Agreements for certain entities by clarifying that independent energy producers may sell electricity to non-profits, local governments, and schools without being considered a public utility and subjected to the regulation required of a public utility.

Full statute available at: http://le.utah.gov/code/TITLE54/htm/54_02_000100.htm

CPACE

Commercial Property Assessed Clean Energy (C- PACE) financing is an innovative way to finance energy efficiency, renewable energy, and water conservation upgrades to commercial buildings. Interested property owners select measures that achieve energy or water savings and receive 100% financing for their project, repaid as a property tax assessment for up to 20 years.

This assessment mechanism has been used nationwide for decades to access low-cost, long-term capital to finance improvements to property that meet a public purpose. During the 2013 Legislative Session, Senate Bill 221 authorized public agencies to issue bonds specifically for the purpose of a renewable energy or energy efficiency upgrades.

C-PACE financing is only available to private property owners, however it could potentially be used to finance clean energy or energy efficiency upgrades on a privately-owned facility in which the Department of Public Utilities rents space. Utah Clean Energy has assembled an Advisory Committee comprised of local governments, financial experts, attorneys, contractors, and businesses to identify best practices and implement pilot projects in 2015. Several local jurisdictions, including Salt Lake City, are currently coordinating to make C-PACE financing available to businesses in their jurisdiction.

Qualified Energy Conservation Bonds

Qualified Energy Conservation Bonds, or QECBs, are a debt instrument that enables qualified states, territories, and local governments to issue tax credit bonds with very low effective interest rates in order to fund energy conservation or renewable energy projects. QECB bonds were authorized by the Energy Improvement and Extension Act of 2008, and the American Recovery and Reinvestment Act (ARRA) of 2009 increased the volume cap for QECBs issued from $800 million to $3.2 billion. This total allocation has been divided amongst the States proportionally based on population, and further allocated to any “large local government” with a population greater than 100,000. Salt Lake City was allocated $1,908,605 and has not yet taken advantage of this allocation. Salt Lake County was allocated $6,392,683 and has used a portion of this allocation. A portion of the overall allocation was reserved to be held by the State of Utah, and $4,306,920 of this allocation remains. QECBs are intended to be used by public entities, however up to 30% of the allocation may be awarded to private entities.

Federal subsidies available for QECBs make them an extremely low-cost financing option. Issuers of QECBs can choose either to issue taxable bonds with a corresponding non-refundable tax credit to the holders of the bonds, or elect to receive a direct cash payment from the Department of Treasury that is equivalent to the amount of the non-refundable tax credit. Of these two options, the direct-pay QECB option is more popular. Both options create a lower effective interest rate for the borrower through Federal subsidies.

Individual jurisdictions may be able to pool their allocations in order to offer larger bonds and minimize the transaction cost of bond issuance per dollar financed. Individual jurisdictions can waive their sub-allocations, in which case they return to the state and can be made available to any entities in the state. Although there are no documented cases of local jurisdictions pooling their sub-allocations without state involvement, there are examples where local jurisdictions have pooled other tax-credit bonds. [4]

QECBs may be issued for “qualified conservation purposes” as defined in section 54D of the U. S. Internal Revenue Code (I. R. C. §54D), including capital expenditures:

- To reduce energy consumption in publicly owned buildings by at least 20%.
- To implement green community programs (including the use of grants, loans, or other repayment mechanisms to implement such programs).
- For rural development (including the production of renewable energy).
- For certain renewable energy facilities (such as wind, solar, and biomass).
- For certain mass commuting projects.

Cities and counties that have received allocations may create their own processes for approving projects within their jurisdictions, and the Governor’s Office of Economic Development is charged with distributing Utah’s allocation. Individual project developers must work either with their local jurisdiction or with the Governor’s Office of Economic Development to arrange for the bond issuance. Applications for QECB from the state of Utah’s allocation are available from the Governor’s Office of Economic Development, and applications are accepted on a quarterly basis and then reviewed by the Private Activity Bond Authority Board at a subsequent Board Meeting. Upcoming application deadlines and board meeting dates are as follows:

Application Deadline Date	Meeting Date
November 24, 2014	January 14
February 23	April 8
May 26	July 8
August 24	October 14
October 26	December 9

For more information and to apply: http://business.utah.gov/programs/pab/energy-conservation-bonds/

[4] http://www. naseo. org/Data/Sites/1/documents/committees/financing/documents/qecb_memo_june13. pdf.

New Market Tax Credits:

The New Markets Tax Credit Program (NMTC Program) was established by Congress in 2000 to encourage investment in businesses and real estate projects located in low-income communities. The NMTC Program allows individual and corporate investors to receive a tax credit against their Federal income tax return in exchange for investing in low-income communities through Community Development Entities (CDEs), organizations with the primary mission of providing investment capital for low-income communities. The Community Development Financial Institutions (CDFI) Fund allocates tax credit authority to local CDEs through a competitive application process. CDEs can then offer tax credits to investors in exchange for equity in the CDE. This allows CDEs to make more flexible investments in distressed areas, at better interest rates than market rates. Investors receive a tax credit of 39 percent of their original investment, claimed over a period of seven years, in addition to the return on their investment in the CDE.

New Market Tax Credits can be used to fund renewable energy projects, although the structure of the project would be quite complicated. In order to take advantage of the tax incentives, a third-party developer could build, own, and maintain a solar photovoltaic system for a public entity. The Department of Public Utilities could then contract to purchase power from the privately owned facility through a Power Purchase Agreement.

Projects which emphasize a strong permanent job creation component are the most competitive and most likely to attract investor and CDE interest. Entities that are interested in utilizing New Market Tax Credits must work closely with a CDE and with potential investors to complete an application. Using New Market Tax Credits is administratively complicated and it may not be worthwhile to pursue New Market Tax Credits for projects costing less than $6-7 million. New Market Tax Credits should be considered for a larger project with good potential to create job growth. New Market Tax Credits could also be used to finance clean energy or energy efficiency upgrades on a privately-owned facility in which the Department of Public Utilities rents space.

New Market Tax Credit allocations can be awarded for renewable energy projects if they are located in census tracts which meet the following criteria designating them as 'low income' areas:

- The poverty rate is at least 20%
- Outside of a metropolitan area, the Median Family Income (MFI) does not exceed 80% of the statewide MFI
- In a metropolitan area, the Median Family Income (MFI) does not exceed 80% of the statewide MFI or the metropolitan area MFI (whichever is greater)

The following sites are located in census tracts which are considered low-income; the last three sites are not discussed in detail in this report, but are eligible for the NMTC program based on their location:

Site	Address
B11-R13	Approximately 1000 E 500 S, Salt Lake City
15th East Reservoir	Approximately 500 S and 1500 East, Salt Lake City
Salt Lake Water Reclamation Facility	1365 West 2300 North, Salt Lake City
500 South Sewer Line	Approximately 500 S and 200 E, Salt Lake City
Salt Lake City Sports Complex	645 S Guardsman Way, Salt Lake City
Sorenson Multicultural and Fitness Center	855 West California Avenue, Salt Lake City
Concord Lift Station	Approximately 1200 West California Avenue, Salt Lake City

For more information: http://www.cdfifund.gov/what_we_do/programs_id.asp?programID=5

Or contact:

Amy Rowland
Field Director
National Development Council
423 W 800 S
Ste. A-313
Salt Lake City, UT 84101
801-557-1537
arowland@nationaldevelopmentcouncil.org

USave Energy Fund:

The Utah U-Save Energy Fund program finances energy related cost reduction retrofits on existing equipment and installations for publically owned buildings by offering loans with low interest rates. A revolving loan mechanism allows borrowers to repay the loans using cost savings realized from the retrofits.

Projects which can be financed through U-Save include (but are not limited to):

- Energy efficient lighting systems
- High efficiency heating, ventilation and air conditioning systems
- Energy management systems
- Energy recovery systems
- Building shell improvements
- Load management projects
- Systems commissioning

Entities considering use of the U-Save Energy Fund are encouraged to evaluate renewable energy technologies, including rooftop solar water and space heating installations, solar photovoltaic, and small wind installations. Hydropower projects can also be eligible for U-Save Energy Fund loans. Projects financed by U-Save must have an average simple payback of five years or less, although borrowers may buy down paybacks to meet this five year limit. Loan repayments begin within sixty days of project completion and are due quarterly. The amount of annual loan repayment is based on the energy cost savings expected to result from the project (but does not change if projected savings differ from actual savings).

Applications for projects are accepted every 1 -2 years, based on the progress of the revolving loan fund. A new notice of loan funding availability will be issued in November, and applications will be accepted beginning in January. Entities who wish to apply for U-Save funds should begin by contacting the Office of Energy Development (OED), and will be asked to sign a Memorandum of Understanding agreeing to submit an Energy Assessment Report (EAR) outlining the proposed project within four months. The Office of Energy Development will reserve funding for the project during this time. When the EAR is complete, the entity applying for funding must submit the EAR along with a Loan Application, and the OED will review the application and approve it for funding. At this point, a Loan Agreement is issued guaranteeing funding for the Energy Conservation Measures outlined in the approved EAR, and the project can be started.

There are specific requirements and milestones projects must meet during the implementation process, including competitive selection of a design engineer and contractors or bidders. Applicants are expected to work closely with OED throughout the design and implementation of the project.

More Information: http://energy.utah.gov/funding-incentives/energy-financing/

Contact:

Teresa Pinkal
Energy Program Specialist
Utah Office of Energy Development
60 E. South Temple, Suite 300
Salt Lake City, UT 84111
801.538.8662

Questar ThermWise Business Custom Rebate Program

The Questar ThermWise Business Custom Rebate Program offers rebates to qualifying customers who complete natural gas saving energy efficiency projects that aren't covered by other existing Questar incentive programs. In order to qualify, the facility implementing the project must be on Questar's commercial General Service rate and must contact Questar Gas prior to purchasing or installing any equipment.

Appendix C: Franchise Agreement

The utility must have a current franchise agreement in order to receive certificates of public convenience and necessity, which are necessary for the utility's infrastructure projects. The city's franchise agreement is up for renewal in 2015 and provides an opportunity for the city to work with the utility on realizing some of its energy goals. Salt Lake City's 2015 Sustainability Plan identifies increasing renewable energy generation and market share as a key goal in the energy realm. This goal can best be achieved if the City is able to complete renewable energy installations in the most advantageous locations, where technical potential and interconnection possibilities with existing infrastructure are high.

Several of the projects described in this memo provide great opportunities for the generation of renewable electricity, and as large energy users the Department of Public Utilities and Salt Lake City both stand to gain (economically as well as in terms of environmental impact) from new sources of renewable energy. A renewed franchise agreement could create a framework though which Salt Lake City can maximize utilization of existing renewable energy sites by working with Rocky Mountain Power to coordinate the construction of new renewable energy resources with optimal locations and mutually advantageous benefits.

When choosing locations for new renewable energy projects, existing rate structures incentivize the DPU to site projects at specific facilities where energy usage is high. The facilities and properties where energy usage is high are not always ideal locations for renewable energy installations, due to space constraints, aging infrastructure, or shading. Were the Department of Utilities able to receive credits towards its general energy usage for the electricity from renewable electricity facilities located throughout its service territory, the DPU and Salt Lake City would have an additional incentive to build larger renewable projects, sited to maximize technical potential. These investments bring new resources to the grid offering all of the benefits associated with clean energy to all Rocky Mountain Power customers, including pollution-free, price-stable sources of electricity, optimally located to maximize energy production and minimize line losses.

Appendix E

Economic Cash Flow Model and Results
Energy Strategies

MEMORANDUM

TO: JEFF NIERMEYER, EXECUTIVE DIRECTOR
DEPARTMENT OF PUBLIC UTILITIES

DATE: DECEMBER 1, 2014

FROM : NICK TRAVIS, ENERGY STRATEGIES
DON HENDRICKSON

RE: SALT LAKE CITY RENEWABLE ENERGY Economic, Financial and Decision Analysis

Introduction

DPU and the Consulting Team identified project opportunities at 5 sites for economic evaluation. This section describes the approach, assumptions and results of the economic analysis. A single power generation technology was evaluated for each of four sites: 15th East Reservoir, B11-R13, Mountain Dell Dam, and Terminal Park Reservoir. Four power generation technologies were evaluated for the fifth site, the Salt Lake City Water Reclamation Facility (SLCWRF). One of the power generation options is to continue to use the existing reciprocating engine generators, the other three are: new reciprocating engines, micro turbines and fuel cells. Each of the four power generation technologies considered at the water reclamation plant was evaluated under two wastewater treatment process scenarios: 1) current process (primary clarification, trickling filters, aeration basins, secondary clarifiers and solids digestion) and 2) biological nutrient removal process. Except for at the B11-R13 and Terminal Park Reservoir sites, it was assumed that all generation could be used to offset site purchases from Rocky Mountain Power.

Economic Analysis

The economic analysis is performed using an annual cash flow model developed in Microsoft Excel. The model includes information on a "Business as Usual" or "BAU" electricity supply scenario, i.e. full requirements from Rocky Mountain Power (RMP) at all sites except partial requirements from RMP for SLCWRF which is assumed to operate one of its two existing engines with no natural gas supplementation. It also includes information on both running two existing engines at a time without and with supplemental natural gas and on each of the options to implement new power generation facilities at each site. The model provides an "incremental analysis", i.e. is used to compare the cash flows and greenhouse gas emissions associated with a comparative scenario to those with an alternative option over the economic life of the option. Refer to **Table 5-1** for a "Strategy Table" identifying key attributes of the options that were modeled.

The engineering firm conducting the study of each option was asked to provide the following information on each option:

215 South State Street, Suite 200 ✦ Salt Lake City, UT ✦ 84111 ✦ phone (801) 355-4365 ✦ fax (801) 521-9142

- In service date (constrained to be the first day of a fiscal year)
- "Overnite" capital cost in 2014$
- Percent of overnite capital cost expended in each fiscal year preceding the in service date
- Electric energy (kWh) produced by season and time period as defined under RMP rate schedules:
    - Winter and Summer
    - On-Peak Hours and Off-Peak Hours[1]
- Incremental non-fuel operating expenses.

Table 5-1. Options Considered in Economic Analysis

STRATEGY TABLE								
		Description						
Scenario/ Project Alternative	Who Conducted Study	Project Site	Site Type	Type of Wastewater Treatment Process	Type of Power Technology	Effective Generation Capacity kW	Economic Life (Years)	Use of Generation
BAU	NA	All Sites	General	Current	Existing Recip (Run 1)	1,320	20	Offset Grid Purchases
1	Sunrise	15th East Reservoir	Water Storage Reservoir	NA	Solar PV	274	30	
3	Sunrise	B11-R13	PRV in Transmission		Hydroelectric	190	50	Sell to Grid
4	Sunrise	Mountain Dell Dam	Surface Water		Hydroelectric	260	50	Offset Grid Purchases
5	Sunrise	Terminal Park Reservoir	Water Storage Reservoir		Solar PV	3,488	30	Sell to Grid
1_WRF	Carollo	SLC Water Reclamation Facility (WRF)	Wastewater	Current	Existing Recip (Run 1)	1,320	20	Offset Grid Purchases
2_WRF	Carollo				Existing Recip (Run 2 No NG)	1,320		
3_WRF	Carollo				Existing Recip (Run 2 with NG)	1,320		
4_WRF	Carollo				New Recip	1,390		
5_WRF	Carollo				Microturbine	844		
6_WRF	Carollo				Fuel Cell	1,330		
1_WRF_BNR	Carollo			Biological Nutrient Removal	Existing Recip (Run 1)	1,320	20	
3_WRF_BNR	Carollo				Existing Recip (Run 2 with NG)	1,320		
4_WRF_BNR	Carollo				New Recip	827		
5_WRF_BNR	Carollo				Microturbine	562		
6_WRF_BNR	Carollo				Fuel Cell	855		

[1] Carollo Engineers, Inc. provided estimates of annual generation which were allocated among seasons and hourly periods pro rata to the hours in each season/period.

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Refer to **Table 5-2** for a summary of assumptions regarding schedule, capital cost, generation and non-fuel operating expenses by option.

The dollar value assigned to generation is a key assumption. For all but two options, it is assumed that generation would offset grid purchases at the project site. In the cases of B11-R13 and Terminal Park Reservoir, generated power exceeds site requirements and would be sold back to Rocky Mountain Power (RMP).

In all instances, the energy generated (e.g. kWh) is assigned a value based on applicable Rocky Mountain Power rates. It is assumed that the solar PV and hydroelectric technologies offer no capacity value whether applied as an offset to purchases or exported to the grid. A capacity value is attributed to cogeneration at the wastewater plant. Specifically, it is assumed that on-site generation capacity at the SLCWRF displaces an equal amount of demand, but incurs demand charges associated with back-up power.

Table 5- 2. Schedule, Capital Cost and Non-Fuel Operating Expense Assumptions

STRATEGY TABLE																
SCHEDULE, CAPITAL COST, GENERATION, AND NON-FUEL OPERATING EXPENSE																
	Description															
							"Overnite" Capital Cost 2014$ Millions				Average Annual Generation, MWh					
							Total	Expenditure Schedule % of Total			Summer Season		Winter Season			
Scenario / Project Alternative	Project Site	Site Type	Type of Wastewater Treatment Process	Type of Power Technology	Effective Generation Capacity kW	In Service Date		FYE 2015	FYE 2016	FYE 2017	On-Peak	Off-Peak	On-Peak	Off-Peak	Total	Non-Fuel Operating Expense 2014 $000/Yr
BAU	All Sites	General	Current	Existing Recip (Run 1)	1,320		$0.0				519	1,662	1,439	1,583	5,203	$156
1	15th East Reservoir	Water Storage Reservoir	NA	Solar PV	274	07/01/16	$0.9	35%	65%		150	31	130	24	335	$13
3	B11-R13	PRV in Transmission		Hydroelectric	190	07/01/17	$1.0	5%	39%	56%	187	248	148	189	773	$15
4	Mountain Dell Dam	Surface Water		Hydroelectric	260		$1.6	5%	39%	56%	245	197	139	108	690	$19
5	Terminal Park Reservoir	Water Storage Reservoir		Solar PV	3,488		$11.3	15%	65%	20%	1,982	403	1,774	330	4,489	$150
1_WRF	SLC Water Reclamation Facility (WRF)	Wastewater	Current	Existing Recip (Run 1)	1,320		$0.0				519	1,662	1,439	1,583	5,203	$156
2_WRF				Existing Recip (Run 2 No NG)	1,320		$0.0				774	2,477	2,145	2,360	7,756	$233
3_WRF				Existing Recip (Run 2 with NG)	1,320		$0.0				883	2,825	2,447	2,691	8,846	$265
4_WRF				New Recip	1,390	07/01/15	$9.4	100%			904	2,893	2,505	2,756	9,058	$181
5_WRF				Microturbine	844		$6.7				632	2,021	1,750	1,925	6,327	$221
6_WRF				Fuel Cell	1,330		$12.1				1,037	3,318	2,874	3,161	10,390	$484
1_WRF_BNR			Biological Nutrient Removal	Existing Recip (Run 1)	1,320		$0.0				471	1,506	1,304	1,435	4,716	$141
3_WRF_BNR				Existing Recip (Run 2 with NG)	1,320		$0.0				883	2,825	2,447	2,691	8,846	$265
4_WRF_BNR				New Recip	827	07/01/15	$8.6	100%			538	1,720	1,490	1,639	5,387	$108
5_WRF_BNR				Microturbine	562		$5.3				420	1,345	1,164	1,281	4,210	$147
6_WRF_BNR				Fuel Cell	855		$10.7				667	2,133	1,847	2,032	6,679	$334

For those options where generation offsets purchases, the specific values assigned per kWh and kW of generation are based on current charges in the electric service schedule that applies to each site. The relevant schedules are 6A, 9, and 31. **Table 5- 3** indicates which schedule applies to each site and sets

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forth values assigned to generation based on relevant current rates. All charges under Schedules 6A, 9, and 31 are projected to increase at 2.85% per year.

Through 2037, sales of energy back to the grid from generation facilities at Terminal Park Reservoir are attributed annual prices that are set forth in RMP Electric Service Schedule No. 37. After 2037, an annual escalation rate of 2.85% is applied. The current annual price paid for customer generation under Schedule 37 is shown in **Table 5-3**.

Under certain options, available digester gas at the SLCWRF must be supplemented with natural gas to produce power and heat for the plant. Carollo estimated the average annual plant heat requirements and fuel balances including available digester gas and required supplemental natural gas. These amounts are shown for each SLCWRF option in **Table 5-4**. The fuel balances are different at the SLCWRF depending on the wastewater treatment process. The differences arise because of the variance in plant heat and power requirements and available digester gas under the BNR and current treatment processes.

Table 5-3. Electric Service Schedule and Relevant Current Rates by Generation Option

STRATEGY TABLE													
ELECTRIC SERVICE SCHEDULE AND CURRENT RATES BY GENERATION OPTION													
	Description												
							Value of Generated Power , 2014$						
							Summer Season			Winter Season			
							Energy Charges per MWh		Demand Charges per kW	Energy Charges per MWh		Demand Charges per kW	
Scenario / Project Alternative	Project Site	Site Type	Type of Wastewater Treatment Process	Type of Power Technology	Use of Generation	RMP Electricity Service Schedule	On-Peak	Off-Peak	Monthly On-Peak	On-Peak	Off-Peak	Monthly On-Peak	Calculated Average Cost of Grid Power per MWh
BAU	All Sites	General	Current	Existing Recip (Run 1)	Offset Grid Purchases	Various							$87
1	15th East Reservoir	Water Storage Reservoir	NA	Solar PV		RMP 6A	$117	$35		$98	$30		
3	B11-R13	PRV in Transmission		Hydroelectric	Sell to Grid	RMP 37	$31			$31			
4	Mountain Dell Dam	Surface Water		Hydroelectric	Offset Grid Purchases	RMP 6A	$117	$35		$98	$30		
5	Terminal Park Reservoir	Water Storage Reservoir		Solar PV	Sell to Grid	RMP 37	$31			$31			
1_WRF	SLC Water Reclamation Facility (WRF)	Wastewater	Current	Existing Recip (Run 1)	Offset Grid Purchases	RMP 31 (9)	$44	$28	$13	$34	$28	$9	
2_WRF				Existing Recip (Run 2 No NG)									
3_WRF				Existing Recip (Run 2 with NG)									
4_WRF				New Recip									
5_WRF				Microturbine									
6_WRF				Fuel Cell									
1_WRF_BNR			Biological Nutrient Removal	Existing Recip (Run 1)		RMP 31 (9)							
3_WRF_BNR				Existing Recip (Run 2 with NG)									
4_WRF_BNR				New Recip									
5_WRF_BNR				Microturbine									
6_WRF_BNR				Fuel Cell									

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Table 5-4. Heat Requirements and Fuel Balances by SLCWRF Generation Option

STRATEGY TABLE

HEAT REQUIREMENTS AND FUEL BALANCES BY SLCWRF GENERATION OPTION

Scenario / Project Alternative	Description										
				WRF Plant Heat Requirements Average MMBtu				WRF Fuel Balances Average MMBtu			
	Project Site	Type of Wastewater Treatment Process	Type of Power Technology	Total Plant Heat	Total Useful Produced by Cogen	Supple-mental Required from Boiler	WRF Plant Power Required Average MWh	Total Fuel Consumed	Digester Gas Available	Flared Digester Gas	Natural Gas Consumed
1_WRF	SLC Water Reclamation Facility (WRF)	Current	Existing Recip (Run 1)	26,250	26,310	301	10,858	66,151	97,637	31,486	-
2_WRF			Existing Recip (Run 2 No NG)		38,851	-		97,128		509	-
3_WRF			Existing Recip (Run 2 with NG)		44,727	-		111,818		-	14,181
4_WRF			New Recip		35,333	-		88,333		9,304	-
5_WRF			Microturbine		27,091	44		77,457		20,180	-
6_WRF			Fuel Cell		19,863	6,388		94,582		3,654	599
1_WRF_BNR		Biological Nutrient Removal	Existing Recip (Run 1)	25,477	23,844	1,634	13,029	61,651	59,672	-	1,979
3_WRF_BNR			Existing Recip (Run 2 with NG)		44,727	-		111,818		-	52,146
4_WRF_BNR			New Recip		21,012	4,466		58,111		1,850	289
5_WRF_BNR			Microturbine		18,025	7,452		60,816		418	1,562
6_WRF_BNR			Fuel Cell		19,863	-		71,555		-	11,883

Further assumptions with respect to non-fuel operating expense; inflation and escalation; plant operating parameters; greenhouse gas emissions coefficients; and cash flow treatment are captured in **Table 5-5**.

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Table 5- 5. Miscellaneous Assumptions

MISCELLANEOUS ASSUMPTIONS				
Description	Value	Unit	Source	Comment
Electricity and Fuel				
Electricity				
Renewable Energy/Green Power Credit	$ -	$/MWh	Energy Strategies	Sensitivity to GHG emissions value used instead
Natural Gas				
Delivered	$ 5.12	per MMBtu/HHV	Energy Strategies	Starting value for FYE June 2015
Operation and Maintenance				
Water Recalamation Facility				
WRF - Existing Reciprocating Engine	$ 0.020	$/kWh	Carollo Engineers, Inc.	Starting value for FYE June 2015
WRF - New Reciprocating Engine	$ 0.010	$/kWh	Carollo Engineers, Inc.	Starting value for FYE June 2015
WRF - Microturbine	$ 0.025	$/kWh	Carollo Engineers, Inc.	Starting value for FYE June 2015
WRF - Fuel Cell:300 kW unit	$ 0.040	$/kWh	Carollo Engineers, Inc.	Starting value for FYE June 2015
WRF - Fuel Cell:1400 kW unit	$ 0.037	$/kWh	Carollo Engineers, Inc.	Starting value for FYE June 2015
WRF - Fuel Treatment System	$ 0.010	$/kWh	Carollo Engineers, Inc.	Starting value for FYE June 2015
Inflation & Escalation				
General Inflation	1.8%	% per year	2014 EIA AEO GDP Price Deflator Index, Reference Case	
Escalation Factors				
Capital Cost	1.8%	% per year	Energy Strategies	
Electricity				
Base Cost	2.85%	% per year	Energy Strategies	
Value of Generated Electricity	2.85%	% per year	Energy Strategies	
Natural Gas	4.0%	% per year	2014 EIA AEO, Reference Case, Mountain, Commercial	
Non-Fuel O&M	1.8%	% per year	Energy Strategies	
GHG Emissions Compliance Value	1.8%	% per year	Energy Strategies	
Plant Operating Parameters				
Boiler Plant Efficiency	80%	MMBtu Heat per MMBtu of Fuel	Carollo Engineers, Inc.	
Greenhouse Gas Emissions Coefficients				
Purchased Electricity				
Current	0.75	MTCO2e/MWh	SLC DPU	Starting value for FYE June 2015
EPA Target Reduction: 2030	27%		Energy Strategies	EPA Clean Power Plan Proposed Rule
Global Warming Potential				
CH4 Emissions	34	100 years	2013 IPCC AR5 p714	
N20 Emissions	298	100 years	2013 IPCC AR5 p714	
Natural Gas: Stationary Combustion				
CO2 Emissions	53.06	kg/MMBtu	The Climate Registry GRP V1.1, Table 12.1	
CH4 Emissions				
Engine Generators	0.5669	kg/MMBtu	The Climate Registry GRP V1.1, Table 12.1	
Turbines	0.0038	kg/MMBtu	The Climate Registry GRP V1.1, Table 12.1	
Fuel Cells	0.0009	kg/MMBtu	The Climate Registry GRP V1.1, Table 12.1	
N2O Emissions	0.0009	kg/MMBtu	The Climate Registry GRP V1.1, Table 12.1	
Total				
Engine Generators	0.0726	MTCO2e/MMBtu	Calculated	
Turbines	0.0535	MTCO2e/MMBtu	Calculated	
Fuel Cells	0.0534	MTCO2e/MMBtu	Calculated	
Digester Gas: Stationary Combustion/Boiler				
CO2 Emissions	53.06	kg/MMBtu	The Climate Registry GRP V1.1, Table 12.1	
CH4 Emissions	0.0009	kg/MMBtu	The Climate Registry GRP V1.1, Table 12.1	
N2O Emissions	0.0009	kg/MMBtu	The Climate Registry GRP V1.1, Table 12.1	
Total Boiler	0.0534	MTCO2e/MMBtu	Calculated	
Digester Gas: Stationary Combustion				
CO2 Emissions	52.07	kg/MMBtu	The Climate Registry GRP V1.1, Table 12.1	
CH4 Emissions	0.0009	kg/MMBtu	The Climate Registry GRP V1.1, Table 12.1	
N2O Emissions	0.0001	kg/MMBtu	The Climate Registry GRP V1.1, Table 12.1	
Total Stationary Combustion Other	0.0521	MTCO2e/MMBtu	Calculated	
Greenhouse Gas Compliance Value				
As Modeled	$ -	2014$/MTCO2e		
Sensitivity Case	$ 25.00	2014$/MTCO2e		
Sensitivity Case	$ 50.00	2014$/MTCO2e		
Cash Flow Treatment				
Type of Year	Fiscal		Energy Strategies	
Year End Date	June 30th		SLC DPU	
Discount Date	1-Jul-14		Energy Strategies	
Discount Rate	5.0%		SLC DPU	

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Applying the assumptions described above, the “incremental” analysis provides insight with respect to the benefits and trade-offs resulting when a course of action is pursued that is different from business as usual. The economic model measures changes (increases and (decreases)) in the following measures for each option versus the relevant business as usual scenario:

- On-site generating capacity, kW
- "Overnite" capital, 2014$ millions
- Average annual generation, MWh
- Non-fuel operating expense, 2014$ millions
- Average annual supplemental natural gas required, MMBtu
- Digester gas flared, % of total available
- GHG emissions, MTCO2e
- Present value cost of utility service, $ millions
  - As modeled assuming $0 per MTCO2e compliance cost
  - Sensitivity analysis at $25 and $50 per MTCO2e compliance cost.

Conclusions

Summary results with respect to these measures are shown in **Table 5-6**. The summary results indicate the following:

- If "cost effective" is defined as not increasing the cost of utility service, the solar projects are not cost effective and the hydroelectric projects become cost effective only assuming a significant cost is assigned to GHG emissions, e.g. between $25 and $50 per MTCO2e.
- There is an opportunity to generate a significant amount of power using solar PV technology at Terminal Park Reservoir. However, there is insufficient value assigned to power sold to the grid to recover the capital investment in such a facility. Even at the 15th East Reservoir where solar PV generation displaces purchases, the value attributed to GHG abatement would need to be in excess of $50 per MTCO2e to recover the invested capital.
- To the extent generation at the SLCWRF is currently being limited to one engine, there appears to be an economic opportunity to operate the existing two engines and consume more of the available digester gas, lowering the cost of utility service and GHG emissions. All new generation options considered for the SLCWRF entail significant incremental capital (between $5 and $12 million) and would result in an increase in the cost of utility service even if a value of $50 per MTCO2e is attributed to GHG emissions.

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Table 5-6. Economic Analysis - Summary Incremental Benefits and Trade-Offs

STRATEGY TABLE																	
ECONOMIC ANALYSIS - SUMMARY INCREMENTAL BENEFITS AND TRADE-OFFS																	
	Description																
							Increase (Decrease) vs. Comparison Scenario										
							On-Site Generating Capacity	"Overnite" Capital	Average Annual Generation	Self Generation to Total Required	Non-Fuel Operating Expense	Average Annual Natural Gas Supplement Required	Digester Gas Flared	Average Annual GHG Emissions	Cost of Utility Service Present Value $Millions		
Scenario/ Project Alternative	Project Site	Site Type	Type of Wastewater Treatment Process	Type of Power Technology	Use of Generation	Scenario Used for Comparison	kW	2014$ Millions	MWh	%	2014$ Millions	MMBtu	% of Available	MTCO2e	$0 per MTCO2e	$25 per MTCO2e	$50 per MTCO2e
BAU	All Sites	General	Current	Existing Recip (Run 1)	Offset Grid Purchases	No Cogen	1,320	$0.0	5,203		$156	0	-34%	-3,271			
1	15th East Reservoir	Water Storage Reservoir	NA	Solar PV		BAU	274	$0.9	335		$13			-252	$0.4	$0.3	$0.2
3	B11-R13	PRV in Transmission		Hydroelectric	Sell to Grid		190	$1.0	773		$15			-582	$0.6	$0.3	($0.1)
4	Mountain Dell Dam	Surface Water		Hydroelectric	Offset Grid Purchases		260	$1.6	690		$19			-520	$0.4	$0.1	($0.2)
5	Terminal Park Reservoir	Water Storage Reservoir		Solar PV	Sell to Grid		3,488	$11.3	4,489		$150			-3,381	$10	$9	$7
1_WRF	SLC Water Reclamation Facility (WRF)	Wastewater	Current	Existing Recip (Run 1)	Offset Grid Purchases												
2_WRF				Existing Recip (Run 2 No NG)		1_WRF	0	$0.0	2,553	24%	$77	0	-32%	-1,558	($1)	($2)	($3)
3_WRF				Existing Recip (Run 2 with NG)			0	$0.0	3,642	34%	$109	14,181	-32%	-1,233	($0)	($1)	($1)
4_WRF				New Recip			70	$9.4	3,855	36%	$25	0	-23%	-2,394	$6	$5	$4
5_WRF				Microturbine			-476	$6.7	1,124	10%	$65	0	-12%	-698	$6	$6	$6
6_WRF				Fuel Cell			10	$12.1	5,187	48%	$328	599	-29%	-3,184	$12	$11	$10
1_WRF_BNR			Biological Nutrient Removal	Existing Recip (Run 1)													
3_WRF_BNR				Existing Recip (Run 2 with NG)		1_WRF _BNR	0	$0.0	4,130	32%	$124	50,167	0%	1,061	$3	$3	$4
4_WRF_BNR				New Recip			-493	$8.6	671	5%	($34)	-1,689	3%	-549	$7	$7	$7
5_WRF_BNR				Microturbine			-758	$5.3	-506	-4%	$6	-417	1%	248	$6	$6	$6
6_WRF_BNR				Fuel Cell			-465	$10.7	1,964	15%	$193	9,904	0%	-729	$12	$12	$12

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References

Alpha Engineering and RB&G, Inc. 2014. Pre-Design Report for Mountain Dell Bypass and Hydro Project. Salt Lake City Department of Public Utilities.

U.S. National Renewable Energy Laboratory. Unknown. Solar Radiation for Flat-Plate Collectors Facing South in Salt Lake City, Utah. Available at http://rredc.nrel.gov/solar/old_data/nsrdb/1961-1990/redbook/sum2/24127.txt. Accessed on July 15, 2014.

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COUNCIL STAFF REPORT

CITY COUNCIL *of* SALT LAKE CITY

Item Schedule:
Briefing: 10/02/18
Public Hearing: n/a
Potential Action: n/a

TO: City Council Members

FROM: Sam Owen, Constituent Liaison / Policy Analyst

DATE: September 27, 2018

RE: Informational: Department of Public Utilities

2018 Comprehensive Water and Sewer Rate Study

GOAL OF THE BRIEFING

Provide information about the process and recommendations of the Comprehensive Water and Sewer Rate Study, especially with regard to changes that will impact customers. **A subsequent transmittal is expected to amend the City's Consolidated Fee Schedule (CFS) to include Rate Study recommendations and new rate structures.**

ISSUE AT-A-GLANCE

During the spring of 2017, the Department of Public Utilities indicated it would begin a public engagement process known as the Rate Advisory Committee (RAC) to solicit deliberate feedback on a number of proposed alternatives to the existing rate structure for water and sewer service. The Rate Study also involved an analysis of stormwater rates; no changes are currently recommended for this Utility. Public Utilities has a practice of conducting a rate study every five to six years.

The RAC met over the course of six meetings and forwarded recommendations to the Public Utilities Advisory Committee (PUAC), which forwarded its selections to the Administration. The Administration worked with financial consultants Raftelis to formalize these selections into a final report, which is the subject of this briefing. The RAC examined a number of alternatives and the present Rate Study models its recommendations from the alternatives that were selected by members of the RAC.

The final Raftelis report makes recommendations for changes to the rate structure for the City's water and sewer service. The final report also includes a number of recommendations for adjustments to existing miscellaneous

Public Utilities fees, as well as new miscellaneous fees, to be included as part of a subsequent proposal to amend the CFS.

Recommendations to the water and sewer rate structures would be revenue neutral, meaning the proposed changes would redistribute existing costs amongst the utilities' customer classes without generating additional funds compared to fiscal year 2019 adopted rates. Rate Study recommendations to miscellaneous fees would reflect actual costs of performing services related to the fees.

Changes to the rate structure in the Water Utility would result in slightly decreased bills for most residential customers, and increases in bills for commercial and industrial users, as well as institutional users. These changes would primarily impact water users connected through larger meter sizes and those consuming larger volumes of water. The changes in this rate structure are in part meant to reflect the essential use affordability priority identified by the RAC (Attachment 1, page 2). Because fixed charges for smaller meters would be reduced, along with reductions in charges for lower volumes of water use, essential water use would be anticipated to become more affordable with adoption of the recommended changes. Some institutional users will also be able to access and continue accessing secondary water for irrigation use which could result in savings; addition of the corresponding secondary water fee to the CFS would also increase transparency.

Changes to the rate structure in the Sewer Utility would result in similar impacts, with residential users experiencing some savings and more intensive users such as commercial and industrial customers experiencing bill increases. These adjustments in part reflect the costs of providing service to more intensive users of this utility. See ADDITIONAL & BACKGROUND INFORMATION for discussion.

No rate structure changes were recommended in the Stormwater Utility, the Street Lighting Utility was not included as part of the present study.

The water service rate differential for City and County customers is also addressed extensively by the Rate Study (See Attachment 1, PDF pages 33, 34 and 114; See also Attachment 2, County Water Rate Differential).

ATTACHMENTS

1. Administrative Transmittal: Comprehensive Water, Sewer and Stormwater Rate Study
2. Memorandum: County Water Rate Differential
3. RAC Stakeholder list

POLICY QUESTIONS

1. Based on the Raftelis Rate Study recommendations, rates would decrease slightly for some groups of users such as single residences, increase slightly for other groups, and increase significantly for still others.

    a. The Department performed extensive outreach over a period of several months to collect stakeholder feedback on various alternatives for new rate structures. Based on information gathered by the Department during this process, the Council may wish to ask, for which groups would the overall impacts of implementing the Rate Study recommendations be anticipated as the most noticeable or significant? Possible users experiencing significant impacts might include:

        i. Housing developers and residents, especially multi-family
        (as costs incurred through increased connection and service fees would likely be reflected in costs passed on to consumers)

        ii. Commercial developers and businesses utilizing new commercial space

iii. Industrial users, especially those with more treatment-intensive discharge, who would pay significantly more for both water service and sewer service

iv. Institutional users such as schools and churches, although impacts for these two customer classes would likely be primarily for water service rather than sewer as well.

b. Based on possible impacts to new construction such as multi-family housing and commercial properties, has the Department conducted outreach or otherwise looked into effects on the production of new supplies in these markets—i.e., if the rate structure and fees were implemented as recommended in the subject Rate Study, has the Department or have others explored likely impacts to the pace of new construction or housing values in Salt Lake City?

i. The Council may wish to explore this question in the context of new development—primarily commercial/industrial—slated for the City's Northwest Quadrant in coming years.

2. A recent proposal from the Administration seeks fee relief for developers of new multi-family housing when affordability requirements are met. How would that program affect the proposed changes, in terms of considering city-fees for developers as a package?

3. Miscellaneous fee recommendations: The Raftelis study includes recommended changes to the rate structures for sewer and water customers, as well as recommended changes to miscellaneous fees. New miscellaneous fees were studied and information provided based on the maximum cost of various services for which the miscellaneous fees are assessed, such as new connections, plan review and repeat inspections. The full cost of performing these services (enumerated in section 6 of the Raftelis report, Attachment 1 page 54) is not currently being offset by fee-for-service revenue, but is covered by other revenue sources (water sales and sewer charges).

   Adoption of the recommended changes to miscellaneous fees would not be revenue neutral, i.e. adopting the fee adjustments as outlined in the Raftelis report would result in new revenue and consideration of adjustments to the fiscal year 2019 adopted budget for Public Utilities. By contrast, the rate structure recommendations are revenue neutral for fiscal year 2019. Therefore, considering the miscellaneous fee recommendations at this time would have both budget and policy impacts.

a. The Council may wish to discuss whether recommended changes to miscellaneous fees and the resulting budget impacts, might be incorporated in a future budget discussion, such as with the fiscal year 2020 budget proposal for Public Utilities, when a holistic proposal could be prepared.

b. Furthermore, the Council may wish to allow more time to review and discuss the proposed fee increases separate from the rate structure proposal. This would allow time to understand the overall budget options, and to identify specific values with regard to the proposed increases and possible ramifications of adjustments.

i. The Council may wish to request that Public Utilities returns with a proposal of a preferred fee increase scenario based on the Raftelis findings.

ii. One purpose might also be to highlight how adopting new, increased fees could offset future rate increases for customers of the Utilities.

iii. The Council may wish to request that Public Utilities recommend miscellaneous fee increases that the Department would like to be considered in the shorter-term, as part of a possible CFS amendment to adopt the proposed rate structure changes. See KEY CHANGES—Miscellaneous Fees for discussion.

KEY CHANGES—Water Utility

Table 1.3: Water – FY19 Utility Presented and FY19 Proposed Raftelis Fixed Charges[1]

Meter Size	FY19 Utility Presented	FY19 Proposed Raftelis	Change - $	Change - %
3/4"	$9.89	$8.84	($1.05)	(11%)
1"	9.89	11.56	1.67	17%
1 ½"	11.68	18.37	6.69	57%
2"	12.68	26.55	13.87	109%
3"	21.28	48.34	27.06	127%
4"	22.78	72.86	50.08	220%
6"	32.88	140.98	108.10	329%
8"	59.11	222.71	163.60	277%
10"	109.63	576.91	467.28	426%
(1) County fixed charges are 1.35 times City fixed charges.				

Table 1.3 above shows monthly fixed charges assessed to customers based on the size of the water meter installed to provide water service. The Raftelis proposed changes to the fixed charges are shown in the highlighted column.

Fixed charges for water service help recover costs related to the Utility's basic capacity to provide service (e.g. costs of existing infrastructure such as reservoirs, pipes, pump stations and so on).

Most residential customers fall in the ¾ - inch and 1-inch meter sizes.

CONVERSION TABLE

Acre foot (AF)	Key definition Hundreds of cubic feet (ccf)	Gallons (g)
0.0022956841	1	748
1	435.6	325,828.8

Table 1.4: Water – FY19 Utility Presented and FY19 Proposed Raftelis Residential Volume Rates[1]
City Customers

Block	FY19 Utility Presented $ per ccf	FY19 Proposed Raftelis $ per ccf	Change - $	Change - %
RESIDENTIAL[2]				
Winter (November – April)				
All Usage	$1.35	$1.30	($0.05)	(3.7%)
Summer (April – October)				
1	$1.35	$1.30	($0.05)	(3.7%)
2	1.85	1.78	(0.07)	(3.8%)
3	2.57	2.47	(0.10)	(3.9%)
4	2.74	2.63	(0.11)	(4.0%)
COMMERCIAL				
Winter (November – April)				
All Usage	$1.35	$1.42	$0.07	5.2%
Summer (April – October)				
1	$1.35	$1.42	$0.07	5.2%
2	1.85	1.94	0.09	4.9%
3	2.57	2.70	0.13	5.1%
4	2.74	2.87	0.13	4.7%
IRRIGATION				
Winter (November – April)				
All Usage	1.85	1.71	($0.14)	(7.6%)
Summer (April – October)				
1	$1.85	1.71	(0.14)	(7.6%)
2	2.57	2.38	(0.19)	(7.4%)
3	2.74	2.53	(0.21)	(7.7%)

(1) County rates are 1.35 times City rates
(2) Includes single residence, duplex, and triplex. See Table 1.1 for the block thresholds for each class.

Table 1.4 above shows volume rates in the form of cost per "ccf," or cost per one hundred cubic feet. One ccf equals approximately 748 gallons. The Raftelis proposed changes would result in lower rates for residential users. The amount decrease in residential water rates is close to the amount the rates were increased in the fiscal year 2019 adopted City budget. Rates for irrigation users would also decrease, and rates for commercial users would increase. See ADDITIONAL AND BACKGROUND INFORMATION for discussion on the redistribution of costs that could be said to have differential impacts on user groups.

Table 3.9: Water – FY19 Utility Presented and Proposed Rate Structures

Block	Residential		CII		Irrigation[1]
	FY19 Utility Presented	FY19 Proposed Raftelis	FY19 Utility Presented	FY19 Proposed Raftelis	FY19 Utility Presented
Winter Period (Nov-Mar)	Block 1 Rate for All Usage		Block 1 Rate for All Usage		Block 1 Rate for All Usage
Summer Rate Structure (April through November)					
Block 1[2]	0-10 ccf	0-10 ccf	0-AWC[3]	0-AWC	0 – Target Budget
Block 2	11-30 ccf	11-30 ccf	AWC-300%	AWC-300%	Target Budget – 300% of Budget
Block 3	31-70 ccf	31-60 ccf	300%-700%	300%-600%	>300% of Target Budget
Block 4	>70 ccf	>60 ccf	>700%	>600%	

(1) No changes to the irrigation rate structure.

(2) Single residence block 1: 0 to 10 ccf
Duplex block 1: 0 to 13 ccf
Triplex Block 1: 0 to 16 ccf

(3) AWC = Average Winter Consumption. "AWC – 300%" means usage greater than a customer's AWC and less than or equal to 300% of the customer's AWC.

Table 3.9 above outlines Raftelis proposed changes to water volume structures. The only recommended change to this aspect of the water rate structure is lowering the threshold at which Block 4 "kicks in." This change would mean that each respective user's highest rate would become active at a lower level of use. Such an adjustment in how rates are assessed can promote conservation.

Table 3.12: Water – FY19 Typical Monthly Summer Bills - Single Residence City Customers

Usage ccf	FY19 Utility Presented	FY19 Proposed Raftelis	Change ($)	Change (%)	% of Summer Bills
0	$9.89	$8.84	($1.05)	(10.6%)	4.8%
5	16.64	15.34	(1.30)	(7.8%)	23.1%
10	23.39	21.84	(1.55)	(6.6%)	18.5%
20	41.89	39.64	(2.25)	(5.4%)	19.5%
30	60.39	57.44	(2.95)	(4.9%)	12.2%
40	86.09	82.14	(3.95)	(4.6%)	7.7%
50	111.79	106.84	(4.95)	(4.4%)	4.8%
60	137.49	131.54	(5.95)	(4.3%)	3.0%
70	163.19	157.84	(5.35)	(3.3%)	1.9%

Table 3.12 above outlines how Raftelis proposed changes to the rate structure would impact non-commercial residential water bills.

- 65.9% of these bills would be estimated to come in between about 5% and 10% percent lower with the proposed changes.
- 27.9% of these bills would be estimated to receive a reduction approximately equal to the last two years of water rate increases.

Table 3.13: Water - Secondary Irrigation Water Rate Calculation

Annual Costs	Units	Unit Cost $ per AF	Unit Cost $ per ccf
Annual return water resource costs	$5,194,331		
Reliable Water Supply, Acre-Feet (AF)	115,713		
Water resource unit cost, $ per AF		$44.89	$0.10335
Water delivery cost	$1,641,658		
Projected volume, AF	14,009		
Water delivery cost, $ per AF		$117.19	
Total, $ per AF		**$162.08**	**$0.37315**
Rate Structure, $ per AF			
Block 2		$162.08	37.3 cents
Block 3		307.95	71.4 cents
Block 4		623.01	$1.434

1 acre-foot (AF) equals 435.6 hundreds of cubic feet (ccf) and 325,828.8 gallons

Table 3.13 above outlines a new secondary irrigation water rate. Irrigation rates are assessed on the basis of a “target budget” for irrigation water use that is formulated using factors like the customer’s permeable area,

historical evapotranspiration and standard watering practices. Water use that exceeds the budget is charged in higher blocks, just like water use for non-irrigation customers.

KEY CHANGES—Sewer Utility

Table 4.11: Sewer - Typical Monthly Bill Comparison

AWC	FY19 Utility Presented	FY19 Proposed Raftelis	Change ($)	Change (%)
0	$11.93	$6.82	($5.11)	(42.8%)
1	11.93	6.82	(5.11)	(42.8%)
2	11.93	6.82	(5.11)	(42.8%)
3	11.93	9.33	(2.60)	(21.8%)
4	12.20	12.44	0.24	2.0%
5	15.25	15.55	0.30	2.0%
6	18.30	18.66	0.36	2.0%
7	21.35	21.77	0.42	2.0%
8	24.40	24.88	0.48	2.0%
9	27.45	27.99	0.54	2.0%
10	30.50	31.10	0.60	2.0%

Table 4.9: Sewer - FY19 Utility Presented Rates[1]

Class	BOD Strength mg/l	TSS Strength mg/l	Flow $ per ccf	BOD $ per ccf	TSS $ per ccf	Total $ per ccf
1	0 – 300	0 – 300	$1.87	$0.78	$0.40	$3.05
2	300 – 600	300 – 600	1.87	1.28	0.82	3.97
3	600 – 900	600 – 900	1.87	2.11	1.39	5.37
4	900 – 1,200	900 – 1,200	1.87	3.02	1.90	6.79
5	1,200 – 1,500	1,200 – 1,500	1.87	3.80	2.46	8.13
6	1,500 – 1,800	1,500 – 1,800	1.87	4.68	2.98	9.53
7	>1,800	>1,800	*Special Rate by Customer*			
Extra Strength Rates, $ per lb						
Chemical oxygen demand (COD)			$0.221			
Biochemical oxygen demand (BOD)			0.442			
Total suspended solids (TSS)			0.264			

(1) Customers billed based on the average water usage for the months November through March (AWC) or a minimum charge is $11.93, whichever is greater.

Table 4.10: Sewer – FY19 Proposed Raftelis Rates[1]

Class	BOD Strength mg/l	TSS Strength mg/l	Flow $ per ccf	BOD $ per ccf	TSS $ per ccf	Total $ per ccf
1	0 – 300	0 – 300	$1.94	$0.68	$0.49	$3.11
2	300 – 600	300 – 600	1.94	1.11	1.00	4.05
3	600 – 900	600 – 900	1.94	1.83	1.70	5.47
4	900 – 1,200	900 – 1,200	1.94	2.62	2.32	6.88
5	1,200 – 1,500	1,200 – 1,500	1.94	3.29	3.01	8.24
6	1,500 – 1,800	1,500 – 1,800	1.94	4.05	3.65	9.64
7	>1,800	>1,800	*Special Rate by Customer*			
Extra Strength Rates, $ per lb						
Chemical oxygen demand (COD)			$0.280	$0.356		
Biochemical oxygen demand (BOD)			0.561	0.713		
Total suspended solids (TSS)			0.619	0.451		

(1) Customers in classes 1 through 6 are billed monthly based on their average winter consumption (AWC) times the sum of the rates for flow, BOD, and TSS or a minimum charge of $6.82 whichever is greater. AWC is the average of water usage for the months November through March.

Tables 4.11, 4.9 and 4.10 above show the difference between fiscal year 2019 adopted rates for sewer service and Raftelis proposed rates for sewer service.

- Table 4.11 is an example of the proposed decrease in the minimum fixed charge for sewer service, from $11.93/month to $6.82/month. This table shows typical monthly bills for discharge that is consistent with all single residential customers and many types of business such as offices. The bills escalate as the customer's average winter consumption (AWC) escalates. For customers with AWC costs lower than the fixed minimum charge, only this minimum charge is assessed. For customers with AWC costs higher than the fixed minimum charge, the minimum charge is not assessed in addition to costs based on the AWC—in other words, these customers are charged on the basis of AWC, without that AWC cost being layered on top of the minimum charge.

- Tables 4.9 and 4.10 show, respectively, fiscal year 2019 sewer rates based on strength of discharge and the Raftelis proposal for adjusting these rates.

    - Sewer rates are assessed on the basis of both flow volume and flow strength (flow strength is measured by the factors biological oxygen demand (BOD) and total dissolved solids (TSS)). These factors are ranked and then multiplied based on that ranking to determine costs for customers.

    - Cost per hundred cubic feet of flow increases with the Raftelis proposal, along with cost per hundred cubic feet of flow based on measurements of each BOD and TSS. The Raftelis proposal also includes cost increases for "Extra Strength Rates," and creates an additional set of factors by which these extra strength rates are assessed as well.

- Although some monthly bills would decrease based on the proposed decrease in the fixed minimum charge for sewer service, many monthly bills would increase based on the proposed adjustments that increase charges for flow, BOD and TSS. These increases in charges reflect cost of service and are revenue neutral based on the fiscal year 2019 adopted revenue figures.

KEY CHANGES—Miscellaneous Fees

The Raftelis findings involve recommendations for miscellaneous fee increases, intended to recoup the full cost of performing various services such as, and not limited to, those related to new connections, plan review and inspections. Costs for performing these services are currently not entirely offset by existing fees but are covered by other existing revenue sources.

If the recommended increases for miscellaneous fees were adopted en bloc as proposed in the Raftelis study, the result would not be revenue neutral. The Council may also wish for more detailed discussion with regard to the fee increases. As such, the Council may wish to request that Public Utilities include the recommendations for miscellaneous fees in its fiscal year 2020 budget proposal, perhaps broken down into one or more preferred scenarios. Doing so might also create the opportunity for ramifications of fee increases to be more fully explored, e.g. in terms of possible offsets to projected rate increases in coming years or in terms of impacts to the development and construction markets in coming years. These aspects of the study recommendations are also addressed in POLICY QUESTIONS.

As part of the current discussion and a possible subsequent amendment to the CFS, the Council may wish to consider Public Utilities' input on whether any fee increases would most need to be considered at this time. It has been indicated that one such recommendation is the suggested change to miscellaneous fees related to stormwater, outlined in table 6.8 below.

Some recommended changes might also entail offsets or balancing with regard to the General Fund. For example, changes related to fire hydrants and flat rates for water use would entail additional expenses for both the City Fire Department and the Unified Fire Authority. Other recommended changes might spur or compel other General Fund-related discussions such as those related to planning and permitting fees, and how costs for performing these services are or are not fully offset by corresponding charges.

Table 6.8: Stormwater Miscellaneous Fees

Fee Type	Existing Service Fee	Calculated Service Fee	Change $	Change %
Storm Water Inspection Fee	N/A	$132	132	New
Discharge into City Storm Water System – Includes 3 site visits	125	132	7	5.6%
Discharge into Stormwater System Re-inspection Fee	30	44	14	46.7%
Discharge into City Stormwater Registration Fee	20	44	24	120.0%

ADDITIONAL AND BACKGROUND INFORMATION

Service demand for the Utilities can be broken down into three main categories, also known as cost components: average day, maximum day and maximum hour.

- For every facility with the system used to provide service (sewer, water, stormwater, etc.), there is an underlying average demand, or uniform rate of usage, exerted on this facility based on what it takes to provide average, every day service for customers. This is the average day cost component.

- Certain facilities are operated and designed to meet the demand above the average day demand, i.e. to provide service for maximum day demand, which is extra-capacity or beyond just average. Costs associated with those facilities are allocated to both the average day and maximum day cost components.

- Similarly, other facilities are designed to meet demands in excess of maximum day requirements, known as maximum hour demand, or extra capacity designed to meet the systems' very highest and least frequent peaks of demand. Costs associated with these facilities are allocated to the average day, maximum day, and maximum hour cost components.

These types of service demand—average day, maximum day and maximum hour—constitute three of the five cost components to which attributes of the total system are allocated. The remaining two are meters & services and billing & collections. Costs are allocated differentially among users of the Water Utility based in part on how the facilities necessary to service the types of customers come into play.

For a simple example, heavy water users place demand on the system that necessitates the creation of facilities associated with meeting higher demand, such as storage and pumping infrastructure. Types of customers associated with heavier water use and thus higher demand on the system are also associated with the need for the infrastructure connected with meeting the higher demand they place on the system. In this way, costs are allocated among the classes of users such that costs of constructing, maintaining and operating infrastructure necessary to serve the respective classes are represented in the differential rates and fees to which various customers are subject.

Attachment 1, PDF page 93 provides one example of how these allocations are made on a percentage basis between five cost components for the Water Utility.

Similarly, allocations are also made among cost components of the Sewer Utility. These allocations correspond to costs assessed to sewer customers, again on the basis of connecting respective costs to provide service with charges assessed to respective classes of customers and the differential needs among the classes.

Attachment 1, PDF page 119 provides one example of how thse allocations are made on a percentage basis among the cost components for the Sewer Utility.

Similar connections between cost of service and charges assessed to recoup those costs underly the Raftelis proposed adjustments to the miscellaneous fees, as well.

APPENDIX

Table 4.7: Sewer – FY19 Proposed Raftelis Customer Class Cost of Service

BOD Class	TSS Class	Flow, ccf	BOD	TSS	Bills	Total
1	1	$16,599,021	$5,783,469	$4,169,093	$1,098,589	$27,650,171
1	2	43,678	15,218	22,489	0	81,386
1	3	19,895	6,932	17,364	0	44,191
1	7	562	196	1,051	0	1,808
2	1	651,072	372,264	163,527	1,678	1,188,540
2	2	1,130,381	646,318	582,020	5,975	2,364,693
2	3	0	0	0	0	0
2	4	97,359	55,667	116,153	941	270,121
3	1	187,736	176,947	47,153	246	412,081
3	2	614,217	578,916	316,253	491	1,509,878
3	3	27,650	26,061	24,133	491	78,335
3	4	1,037	977	1,237	41	3,292
4	1	47,383	63,920	11,901	41	123,245
4	2	545,789	736,280	281,020	1,193	1,564,282
4	3	842	1,136	735	0	2,714
4	4	9,872	13,317	11,777	0	34,967
5	1	89,625	152,133	22,511	0	264,268
5	2	2,245	3,811	1,156	82	7,294
5	4	1,620	2,750	1,933	0	6,303
5	5	713	1,210	1,101	0	3,024
6	1	95,414	199,466	23,965	0	318,844
6	2	18,945	39,604	9,754	0	68,303
6	4	1,058	2,213	1,263	0	4,534
7	1	42,512	327,616	10,784	41	380,952
7	2	54,738	486,111	28,466	0	569,315
7	3	50,614	542,061	44,635	41	637,351
7	4	6,675	60,952	8,043	0	75,670
7	5	778	10,111	1,213	0	12,102
Total		**$20,341,431**	**$10,305,656**	**$5,920,730**	**$1,109,849**	**$37,677,666**

Table 4.7 exhibits the proportions between cost of service and the number of customers to whom sewer service would be provided. For example, discharge-intensive customers that rank BOD class 7 and TSS class 3 would account for only 41 bills, but $637,351 in total cost of service. By these figures, the average monthly cost of serving these discharge-intensive customers would be $15,545.15 each, compared to an average cost of $25.17 serving BOD class 1 and TSS class 1 customers (largely residential). The significantly higher average monthly cost of service for serving discharge-intensive customers would reflect the cost of volume and treatment capacity that must be in place to serve these customers.

JACQUELINE M. BISKUPSKI
Mayor

DEPARTMENT OF
PUBLIC UTILITIES

CITY COUNCIL TRANSMITTAL

Patrick Leary, Chief of Staff

Date Received: 4/4/2019
Date sent to Council: 4/9/2019

TO: Salt Lake City Council
Charlie Luke, Chair

DATE: April 4, 2019

FROM: Laura Briefer, MPA
Director, Department of Public Utilities

SUBJECT: Request for a City Council resolution supporting the pursuit of the Water Reclamation Facility reconstruction as required to comply with Utah Administrative Code R317-1-3-3 and Utah Department of Environmental Quality Permit Requirements

STAFF CONTACTS: Jesse Stewart, Deputy Director, jesse.stewart@slcgov.com; Jason Brown, PE, Chief Engineer, jason.brown@slcgov.com; Lisa Tarufelli, Finance Administrator, lisa.tarufelli@slcgov.com

Laura Briefer, Jesse Stewart, Jason Brown, and Lisa Tarufelli will address the Council on this resolution.

DOCUMENT TYPE: Resolution (Exhibit A)

RECOMMENDATION: Approve a resolution supporting the pursuit of the reconstruction of the Water Reclamation Facility, particularly the implementation of biological phosphorus removal technology to meet requirements of Utah Administrative Code R317-1-3-3. It is also required that the adopted resolution include an approximate budget for the construction of the selected technology for conformance with the approved variance requirements.

BUDGET IMPACT:
The reconstruction of the Water Reclamation Facility (WRF) has been in the Public Utilities' long term plan and the projected costs have been projected in the Department's longer term budget planning since at least in 2015. At this time, the total estimated costs for design and construction of the new WRF is $528,130,000 (Exhibit B). The Department has worked with the Administration, Council, and the Public Utility Advisory Committee over the last several years to develop a long term financing and rate strategy. Public Utilities' goal of the financing strategy is to minimize the impact to the community, and balancing the financing, infrastructure, and regulatory requirements of the new WRF.

The costs for the WRF will be covered with a combination of rate increases, revenue bonds, and possibly longer term loans through state and federal programs. As such, Public Utilities is providing two

representative financing scenarios for the project, one using traditional revenue bonds, and the other using a federal loan for 49% of the project using under the federal Water Infrastructure Finance and Innovation Act (WIFIA). The scenarios, presented in **Exhibit C**, are presented in the context of the Sewer Utility's overall long term budget and cash flow planning in order to provide context to the budgetary requirement of the resolution.

Public Utilities plans to apply for a WIFIA loan for this project and believes this project would be competitive in the loan process (see WIFIA fact sheet, **Exhibit D**). We are also investigating state loans. Securing a loan under the federal WIFIA or state water infrastructure lending programs would mitigate some of the near-term impacts to ratepayers. In addition, the WIFIA loan program provides for a longer term (35 year) payback, which would distribute costs of the project more fairly across the generations that will benefit from the new WRF. The WIFIA and state loans require Buy America and federal wages, which may increase the cost of the project. Any additional costs can also be mitigated by the interest rates and longer payback terms.

Success in a WIFIA or state loan process is not guaranteed, in which case revenue bonding would be required. Therefore, Public Utilities is providing budgetary information for revenue bonding and federal/state loan programs.

BACKGROUND/DISCUSSION:
The Utah Department of Environmental Quality (UDEQ) adopted a new rule that went into effect on January 1, 2016 (R317-3-3), limiting the amount of phosphorus permitted to be discharged by wastewater treatment plants into State water bodies. Public Utilities was fully engaged with the rule making process and provided numerous comments and concerns outlining the impact to Salt Lake City and sewer rate payers. The new rule specifies compliance by January 1, 2020; however, the rule also allows for the Director of the UDEQ Water Quality Division to permit a variance to the compliance date if due diligence is made towards meeting the requirements of the rule.

Due to numerous issues associated with meeting the January 1, 2020 compliance date, including the age of the existing WRF, construction schedule, and procurement of funding, Public Utilities requested a variance on March 26, 2018. Conditional approval from UDEQ was received on May 29, 2018 to extend the compliance date to January 1st 2025. One of the conditions of the variance states that the Public Utilities Department must submit, no later than July 1, 2019 "*A City Council resolution supporting the pursuit of the facility upgrade to the selected biological phosphorus removal technology. The resolution shall include the approximate budget for the facility upgrade.*" **Exhibit E** provides all relevant regulatory correspondence to date.

It should be noted that over the last several years, Public Utilities evaluated numerous alternatives of meeting the new phosphorus rule that included alternatives to retrofit the existing WRF. Due to the age and condition of the existing WRF, it was determined that retrofitting the 55-year old WRF was not physically or economically feasible. It was also determined that the existing WRF has met its useful life, and needs to be reconstructed. For example, the existing WRF does not meet current seismic standards, and is vulnerable to disruption during extreme flood events. Engineering reports documenting these analyses are available to review upon request. Public Utilities can also present a summary of these studies if needed.

Public Utilities is currently designing the new WRF. The design and construction costs have been planned within Public Utilities' budgets starting in fiscal year 2018, and through 2025. This includes bond revenue

and design costs in the proposed FY 2020 budget. Currently, the estimated cost for construction of the new WRF is $528,130,000. This cost may change as engineering designs are completed, and are subject to evolving regional construction costs.

The construction is phased over seven years with the objective of meeting the rule by 2024, one year ahead of the regulatory compliance requirement. The 2024 objective is to allow for full commissioning of the new WRF to ensure the plant and all of its operational components will be in compliance by the 2025 deadline.

PUBLIC PROCESS: Public Utilities has engaged the public regarding the need for the new WRF throughout the last few years. Public Utilities has engaged the public regarding rate increases associated with financing the WRF. Examples of public engagement include community council meetings, periodic updates during City Council work sessions (particularly during annual budget discussions), media engagement, and postcard mailings. Public Utilities is continuing to engage the public, and has retained the public engagement firm, Wilkinson Ferrari, to assist. We continue to provide updates to community councils, and will be holding public open houses starting April 2019. Because of the duration of the project, Public Utilities' engagement will be ongoing and iterative.

EXHIBITS:

A. Council Resolution Supporting the Reconstruction of the Salt Lake City Water Reclamation Facility

B. Engineering Estimated Cost for new WRF and Site Plan

C. Estimated Design and Construction costs and rate scenarios for new WRF from 2019-2025, as a component of overall Public Utilities Sewer Planning Budget
    i. Scenario 1 – Revenue Bonds and Rate Increases
    ii. Scenario 2 – Federal Water Infrastructure Finance Improvement Act (WIFIA) Loan and Rate Increases

D. WIFIA Fact Sheet

E. Official correspondence between Salt Lake City Department of Public Utilities and Utah Department of Environmental Quality establishing a permit variance for Technology-Based Phosphorus Effluent Limits, dated November 6, 2017 through March 21, 2019

Exhibit A

Council Resolution Supporting the Reconstruction of the Salt Lake City Water Reclamation Facility

RESOLUTION NO. ________ OF 2019

Supporting Water Reclamation Facility Upgrade

WHEREAS, the city's Public Utilities Department operates its Water Reclamation Facility (WRF) that treats approximately 35 million gallons of wastewater per day and the Department has been planning to upgrade and replace the WRF since 2015. The city operates the WRF pursuant to its State issued UPDES Discharge Permit No. UT0021725.

WHEREAS, the Utah Department of Environmental Quality (UDEQ) adopted a new rule that went into effect on January 1, 2016 (R317-3-3), limiting the amount of phosphorus permitted to be discharged by wastewater treatment plants into State water bodies. The new rule specifies compliance by January 1, 2020; however, the rule also allows for the Director of the UDEQ Water Quality Division to permit a variance to the compliance date if due diligence is made towards meeting the requirements of the rule;

WHEREAS, due to numerous issues associated with meeting the January 1, 2020 compliance date, including the age of the existing WRF, construction schedule, and procurement of funding, the Public Utilities Department requested a variance on March 26, 2018, to extend the compliance deadline. Conditional approval from UDEQ was received on May 29, 2018 to extend the compliance deadline to January 1, 2025;

WHEREAS, the Public Utilities Department is currently designing the new WRF. The design and construction costs have been planned within Public Utilities' budgets starting in fiscal year 2018, and through 2025. This includes bond revenue and design costs in the proposed FY 2020 budget. Currently, the estimated cost for construction of the new WRF is $528,130,000, with the construction to be phased over seven years with the objective of meeting the rule by 2024, one year ahead of the regulatory compliance deadline;

WHEREAS, UDEQ's approval of the variance requested by the Public Utilities Department includes certain conditions for the extension of time for compliance under Rule 317-3-3. One condition is that the City Council adopt a resolution supporting the pursuit of the WRF upgrade to achieve the permitted biological phosphorus levels; and

WHEREAS, the Public Utilities Department has provided to the City Council with adequate information for it to make an informed decision supporting the upgrade of the WRF facility.

THEREFORE, BE IT RESOLVED by the City Council of Salt Lake City, Utah, as follows:

The City Council of Salt Lake City, Utah does hereby support the pursuit of the WRF upgrade to achieve the selected biological phosphorus levels in order to comply with the standards established for Salt Lake City under its UPDES Discharge Permit; such upgrade will require the approximate budget of $528,130,000, which is subject to future appropriations of the City Council.

Passed by the City Council of Salt Lake City, Utah, this _____ day of ______________, 2019.

SALT LAKE CITY COUNCIL

By: ________________________
CHAIRPERSON

ATTEST AND COUNTERSIGN:

____
CITY RECORDER

Approved as to form: ERV
Salt Lake City Attorney's Office
E. Russell Vetter, Deputy City Attorney
Date: 4/2/19

HB_ATTY-#76249-v1-Resolution_Supporting_WRF_Upgrade_3-19

Exhibit B

Engineering Estimated Cost for new WRF
and Site Plan

PROJECT NUMBER	CAP REQUEST NUMBER	PROJECT DESCRIPTION	BUDGET YEAR 2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	
		NEW WATER RECLAMATION FACILITY								
524905271		NEW PLANT - CORE DESIGN/BUILD RECLAMATION FACILITY	1,750,000	10,250,000	5,000,000	3,500,000	2,000,000	400,000		
524905335		WRF MASTER PLAN IMPLEMENTATION - CAPITAL PROJECT SUPPORT	4,500,000	4,500,000	4,500,000	3,500,000	3,500,000	2,500,000	1,500,000	
		NEW PLANT - MECHANICAL DEWATERING (CONSTRUCTION)	33,500,000	440,000						
		NEW PLANT - BNR LIQUID STREAM (CONSTRUCTION)		41,020,000	155,430,000	120,360,000	15,960,000			
		NEW PLANT - SOLIDS HANDLING (CONSTRUCTION)					41,160,000	2,840,000		
		NEW PLANT - ADMIN OPS (CONSTRUCTION)		14,090,000	1,620,000					
		NEW PLANT - DEMOLITION (CONSTRUCTION)						5,000,000	1,500,000	
525400068	2017-2050	NEW PLANT - PROFESSIONAL DESIGN SERVICES	9,500,000	7,800,000	7,500,000	5,100,000	2,100,000	2,000,000	1,000,000	
524905339	2017-2051	NEW PLANT - CM/GC DESIGN SERVICES	3,000,000	2,500,000	1,000,000					
524905337	2017-2052	NEW PLANT - WATER RENEW PUBLIC OUTREACH	300,000	250,000	250,000	250,000	250,000	250,000	250,000	
524905340	2017-2054	NEW PLANT - PILOTING AND DEMONSTRATION TESTING	2,000,000	2,000,000						
		NEW PLANT - PROJECT DOCUMENTATION	150,000	60,000	60,000	60,000	60,000	60,000	60,000	
		TOTAL CAPITAL IMPROVEMENTS	54,700,000	82,910,000	175,360,000	132,770,000	65,030,000	13,050,000	4,310,000	**528,130,000**

Basis of Estimate

Nutrient Project – Pre-Design Estimate Salt Lake City Water Reclamation Facility

Prepared for
Salt Lake City, Utah
Department of Public Utilities

February 8, 2018

Contents

SLCWRF – Nutrient Pre-Design Estimate
Basis of Estimate

TABLE 0.1
Estimate Information
SLC-WRF – 15pct Design

Estimate Classification	Class 4
Requested By	Brewer, Mike/SLC
Estimated By	Bredehoeft, Pete/ATL, Sisneros, Steve/DEN
Estimator Phone	678-373-3235
Estimate Date	February 8, 2018

1. Purpose of Estimate

The purpose of this estimate of construction cost is to establish an Engineer's opinion of probable construction cost at the predesign level. Design costs, construction management costs and Owner costs are being handled at the program level.

2. General Project Description

The Salt Lake City Water Reclamation Facility (SLCWRF) is located at 1365 West 2300 North, Salt Lake City, Utah. The wastewater treatment facility owned and operated by the Salt Lake City Department of Public Utilities (SLCDPU). This construction estimate is for the phase 1 improvement (only), which replaces the existing facility and maintains the capacity of the plant to 56 MGD (AAF). The improvements include: influent pipeline, influent pump station (off-site) screening & grit removal (on-site), primary treatment, secondary treatment, chemical treatment & storage, UV disinfection, solids handling upgrades, including a new dewatering building to replace drying beds, thermal-alkaline hydrolysis, post aerobic digestion, thermal drying and new Combined Heat & Power facilities. Other improvements include new administration building, utility water pump station, primary electrical services and distribution, and standby power systems, and improvements to the natural wetland treatment system.

3. Overall Costs

The following is a summary breakdown of the construction costs.

Accuracy Range - High		Accuracy Range - Low
+25%	Construction Cost without Escalation	-20%
$482,467,000	$ 385,973,000	$ 308,779,000
	Construction Cost with Escalation - 5.32% (Buy-out)	
$508,133,000	$ 406,506,000	$ 325,205,000

This cost estimate has been prepared for guidance in project evaluation and implementation from the information available at the time of the estimate. The final costs of the project will depend on actual labor and material costs, competitive market conditions, final project costs, implementation schedule and other variable factors. As a result, the final project costs will vary from the estimate presented herein. Because of this, project feasibility and funding needs must be carefully reviewed prior to making specific financial decisions to help ensure proper project evaluation and adequate funding.

4. Scope of Work

This project consists of the following areas of improvements or facilities:

- Contractor – Startup & Testing
- Sitework – including 15' of imported fill for new facilities – Phase 1 Only
- Yard Piping – 28,171' LF or 5.3 miles
- Bypass Pumping, Connections and Tie-ins – Allowance
- Demolition of Existing Drying Beds – 26 acres
- Demolition of Building and Structure – Phase 1
- Demolition of Building and Structures – Bid Items (Phase 2)
- Existing Electrical Upgrades – Allowance
- Influent Pipeline – 3 Runs x 54" Dia – 4,300 LF
- Influent Pump Station & Course Screening – Offsite
- Influent Pump Station Odor Control Pad - Offsite
- Influent Connection Junction Boxes - Offsite
- Influent Flow Meter Vault
- Headworks Building – Onsite
- Headworks Odor Control Pad
- Grit Basin Facility
- Primary Influent Splitter Box
- Primary Clarifiers – 185' Dia – 4 EA
- Primary Effluent Splitter Box
- Primary Sludge Pump Station
- Primary Scum Pump Station
- Bioreactor Splitter Box
- Bioreactor Basin
- Secondary Clarifiers – 210' Dia – 4 EA
- Secondary Scum Pump Station
- Return Activated Sludge Pump Station
- Return Activated Sludge Splitter Box
- Blower Building – 19,46 SF
- Chemical Building – 5,714 SF
- UV Disinfection Building - Reto-fit of Existing Aeration Basins.
- Combined Heat and Power (CHP) Building – 3,800 SF
- Administration Building – 2-Story - 10,000 SF
- Operations Building – 20,000 SF
- Post Aerobic Digestion Tank
- Post Aerobic Diegestion Mechanical Building – 8,236 SF
- Dewatering Building – 2-Story – 12,440 SF
- Dryer Building – 12,136 SF
- Utility Water Pump Station – Reto-fit of Existing Aeration Basins
- Plant Drain Pump Station

- Effluent Parshall Flume – Flow Meter
- Plant Generators – Outdoor Units – 1.5MW – 2 EA – At IPS
- Plant Generators – Outdoor Units – 12.5MW – 4 EA – At WRF

5. Markups

These markups are based upon general assumptions about how the project will be contracted. Actual markup percentages may vary from those shown here, and are the responsibility of the bidding contractor.

TABLE 5.1
General Contractor Markups
Project Name

Contractor General Conditions	8.00%
Sales Tax on Material – Salt Lake City	6.85%
Contractor Overhead Home Office	4.00%
Contractor Profit	6.00%
Bonds and Insurance	2.16%
Estimate Contingency	10.00%
Escalation Rate – Based upon Contractor Buyout – 4 Months	5.32%

6. Escalation Rate

This estimate includes Escalation with the assumption that construction NTP will start in March 2020 with the midpoint of construction being June 2022. It is assumed that there will be 50 months (4.2 years) of construction duration. The full escalation of the project equates to an escalation factor of 10.81%. However, the escalation included in the cost estimate is based upon a 4-month contractor buyout or locking in of major equipment purchases and securing of subcontractors. This buyout escalation equates to be an escalation factor of 5.32%. (See appendix for Escalation Analysis.) The buyout escalation factor amount was used in this estimate.

This estimate assumes the project is based upon a design, bid, build contracting approach with single contract award. Phasing of construction packages is unknown and will be determined at a later date. This estimate assumes the NTP for a designer will be April 1, 2018, with a 24 month design period. The bid and award period for the construction contract will be based upon the CM At Risk procurement and be concurrent with the Design.

This CH2M HILL escalation forecast is based upon economic data from Global Insight, Inc. and the United States Bureau of Labor Statistics.

7. Estimate Classification

This cost estimate prepared is considered a feasibility or Class 4 estimate as defined by the Association for the Advancement of Cost Engineering International (AACE). It is considered accurate to +25% to -20%, based on a 15% pre-design deliverable.

8. Estimate Methodology

This cost estimate is considered a bottom rolled up type estimate with cost items and breakdown of Labor, Materials and Equipment. Process equipment quotations were obtained for the majority of major equipment. The estimate includes detailed takeoff and pricing for all divisions of work. The estimate may include allowance cost for plumbing

and HVAC. Other general allowances have been included in the estimate. Dollars per SF cost for the Administration and Operations buildings.

9. Cost Resources

The following is a list of the various cost resources used in the development of the cost estimate:

- CH2M HILL Historical Data
- R.S. Means
- Vendor Quotes on Equipment and Materials where appropriate
- Estimator Judgment

10. Labor Costs

The estimate has been adjusted for local area labor rates, based upon Davis Bacon rates for Salt Lake City, UT, 2017 rates.

Labor unit prices reflect a burdened rate, including: workers compensation, unemployment taxes, Fringe Benefits, and medical insurance.

11. Taxes

An 6.85% sales tax for Salt Lake City was added to all material costs within the estimate including process equipment. However, Certain pollution control facilities are exempt from sales tax "R865-19S-83. Pollution-Control Facilities Pursuant to Utah Code Ann. Section 59-12-104). An adjustment for tax exception has not been included in this estimate.

12. Major Assumptions

The estimate is based on the assumption the work will be done on a competitive bid basis and the contractor will have a reasonable amount of time to complete the work. All contractors are equal, with a reasonable project schedule, no overtime, constructed as under a single contract, no liquidated damages.

This estimate should be evaluated for market changes after 90 days of the issue date. It is assumed that much of the fabricated equipment will be shipped from the mainland USA.

Yard Piping

1. If a discrepancy on yard piping with facility exposed piping, the size shown on the yard piping will dictate. The facility drawing size will dictate on the exposed piping.

Grit Basin Facility

1. Influent Well Slab – Assumed 24" thick.
2. Cutthroat Flow Channel Slab – Assumed 18" thick.
3. Influent Flow Channels Slab – Assumed 18" thick.
4. Grit Basin Slab – Assumed 18" thick.

Primary Clarifiers

1. Base Slab – Assumed average of 16" thick.

Primary Sludge Effluent Splitter Box

1. Base Slab – Assumed 30" thick.

Primary Scum Pump Station

1. Pumps – Assumed 15hp

Secondary Scum Pump Station

1. Pumps – Assumed 15hp

Bioreactors

1. Base Slab – Assumed 36" thick.

Blower Building

1. Base Slab – Assumed 18" thick.

Secondary Clarifiers

1. Base Slab – Assumed 24" thick.

RAS/WAS Pump Station

1. Base Slab – Assumed 24" thick.
2. RAS Pumps – Assumed VFD is required and included in estimate.

Utility Water Pump Station

1. Non-Potable Water – Small Pumps – Assumed Vertical Turbine Pumps – 50hp/EA.

RAS Splitter Box

1. Base Slab – Assumed 30" thick.

Chemical Building

1. Base Slab – Assumed 18" thick

UV Disinfection Facility

1. Assumed new building is only over new channel space only, and extends out into new truck bay area.
2. Assumed new truck bay area base slab is 18" thick.

Post Aerobic Digestion

1. Base Slab – Assumed 24" thick

Post Aerobic Digestion Mechanical Building

1. Base Slab – Assumed 24" thick
2. Tank Wall – Assumed 24" thick

Dewatering Building

1. Base Slab – Assumed 24" thick.
2. Sludge Storage Pad – Assumed 24" thick with 4' high containment wall. Included an allowance for water collection of sludge water.

CHP Building

1. Base Slab in Engine Area – Assumed 36" thick, 12" in Electrical Room

Existing Electrical System Upgrades – Allowance

1. Existing Electrical System Upgrades – Assumed 6 men for 6 months and $1,500,000 material allowance.

Headworks Building

1. Lower Base Slab – Assumed 36" thick.
2. Perimeter Walls – Assumed 24" thick.
3. Building – Assumed CMU block with Double Tee Roof. Assumed 32' overall height.
4. Assumed 4 Ton Bridge Crane.

5. Special Coatings – Assumed T-Loc liner for all channels.
6. Footprint 144' by 60'
7. The building will sit on 15' of compacted fill at the new WRF
8. 4 bar screens
9. One extra spot for a 5th screen at final build out
10. 2 compactors
11. 2 loadout bays

Effluent Parshall Flume

1. Assumed new open channel, 200' Long x 5' wide x 8' high walls. Cast in place construction is assumed.
2. Flow Meter insert for Parshall Flume
3. Assumed grating over top of open channel.
4. Assumed a concrete 6' wide cantilevered deck x 200' long with stairs and handrail

Wetlands – Rock Weir and Spillway

1. The rock weir and spillway is constructed of 12"-18" rip-rap material, with filter fabric.
2. The approximate dimensions are 100' long x 17' wide x an average of 4' high.
3. Grading of Wetlands is based upon drawing C-14-100

Plant Drain Pump Station

1. Assumed plant drain system is the same as the Primary and Secondary scum pump station.

Electrical

1. Have used the Electrical One-line Drawings as reference for major electrical gear and MCC's.
2. Electrical Gear as shown on electrical one-lines costs are based on estimator judgment and previous project cost.
3. Generators cost include belly fuel tank and sound enclosure placed on slab exposed to environment.
4. Generator Switch Gear, includes costs for weather-proof enclosure to be located on slab exposed to environment.
5. Electrical one-lines for power distribution requirements, made assumptions and best judgment for general routing.
6. Duct-bank cost allowances based on estimator judgement and past projects of similar design.
7. Over-head Power cost allowances based on estimator judgement.
8. Utility Transformers carried in estimate as depicted on Electrical One-lines (Utility power feed and source to be supplied by Utility Company).
9. General electrical requirements, such building electrical, HVAC, etc. cost is accounted for in the Facility Electrical Allowance.

Instrumentation and Control (I & C)

1. Contractor Programming – Included cost for contractor to provide programming of installed equipment only.
2. I & C - Is estimated based on historical standard percentages used for typical facilities and processes.

Influent Pipeline

1. Pipeline – 54" Dia x 3 Run x 4,300' LF – Assumed HDPE pipe, glass line.
2. Pipeline – assumed pipeline is at mimimum buried depth.
3. Pipeline – assumed 10% for sheeting and shoring is required – 15' Embed.
4. Pipeline – assumed 20% requires well point dewatering for 4 months.
5. Pipeline – assumed no pipeline crossings.
6. Pipeline – assumed no pavement pavement restoration or improvements.
7. Pipeline – assumed hydro seeding along route, 4,300 LF x 50'wide.

Influent Pipeline – Connection Boxes

1. 1 interceptor box for pipelines at 15' by 28' by 30' deep
2. 1 interceptor box for pipelines at 14' by 12' by 30' deep
3. 1 junction box for pipelines at 14' by 34' by 30' deep
4. 280 feet of 48 inch dia. FRPMP pipeline @ 30 feet deep
5. 350 feet of 84 inch dia. FRPMP pipeline @ 30 feet deep
6. 70 feet of 96 inch dia. FRPMP pipeline @ 30 feet deep

Influent Pump Station

1. Existing plant footprint approx. 7,500 ft. sq.
2. Use 9,750 ft. sq. – 30% larger
3. 30 feet deep
4. Existing pumps 4 ea. @ 350 Horsepower
5. New pump use 4 ea. @ 770 Horsepower – approx. 30% larger
6. Space for 1 additional pump at final build out
7. New pump station will have an odor control facility
8. No additional pump station will be required at the new WRF

Sitework

1. Demolition of Existing Roadway Pavement – assumed 6" overall depth.
2. New Asphalt Pavement – Assumed 8" base stone course, 3" asphalt base course, 2" asphalt wearing course.
3. Sidewalks – assumed 5% of asphalt pavement area.
4. Stormwater System – Allowance – 8,000 LF of 36" – 18" RCP Pipe and 40 catch basins.
5. Gas Utilities – Allowance – 5,000 LF of 2" Dia pipe.
6. Dump Charge – Assume County Landfill will be used. This could be a potential large project savings if the City could negotiate waving or a lower disposal fee charge.
7. Imported Fill – Overall site has 15' of imported material. Assumed clean fill, imported from 10 miles round trip at a cost of $9.00/CY. Imported fill is only in new facilities area, located at the demolished sludge drying beds and phase 1 work area only.
8. Hauling – assumed 10 miles round trip for hauling of offsite soil waste material.
9. Disposal or Dump Fee is based upon Salt Lake County Landfill prices:
    a. Construction Debris - $31.35/TON
    b. Asphalt/Concrete $5.00/Ton
    c. Soil Disposal - $5.35/Ton
    d. Assumed contractor will sort and separate concrete and rebar to minimize cost.
10. Dewatering – Since overall site has 15' of fill material – assumed well point dewatering is required for any facility deeper than 12' deep.
11. Shoring – Assumed facility depths over 12' deep will require sheeting and shoring to keep out dewatering and for working space for construction of that facility.
12. Imported Fill:
    a. Imported 15' – Clean Fill – 880,000 CY
    b. Scarify, Compaction, Rough and Final Grading – 153,000 SY
13. Seeding Construction Area – 860,000 SF
14. Asphalt Pavement – 375,000 SF

Demolition

The demolition of existing sludge drying beds and various facilities, includes the following assumptions:

1. Asphalt Pavement demolition – 325,000 SF
2. Sludge Drying Beds:

   a. Assumed SLC staff will removal and clean out all existing sludge and sludge water prior to contractor demolishing the sludge drying beds.
   b. Assumed 6" of concrete will be demolished and hauled off site, 21,200 CY.
   c. Assumed 1.5' of berm material and contaminated sludge material, 63,400 CY will be hauled off site.
3. Aeration Basin – 10 crew days to demolish.
4. Tower Structure – 10 crew days to demolish.
5. Bid Options:
   a. Blower Building – 7 crew days to demolish
   b. Chemical Building – 5 crew days to demolish
   c. Chlorine Contact Basin – 10 crew days to demolish
   d. Primary Clarifiers 140' dia – 4 EA – 20 crew days to demolish
   e. Secondary Clarifiers 140' dia – 4 EA – 20 crew days to demolish
   f. Trickling Filters 190' Dia – 4 EA – 20 crew days to demolish

Startup and Testing

1. Assumed contractor startup and testing period of 4 months.

Special Coatings

1. T-Loc Liner is included for the base slab, walls, channels and upper elevated slab on the following facilities:
   a. Influent pump station.
   b. Influent junction boxes.
   c. Headworks.
   d. Grit basin facility.
2. Special Coatings – Epoxy Flooring is included in the following facilities:
   a. Blower building.
   b. Chemical building.
   c. CHP building
   d. Post aerobic digestion mechanical building.
   e. Dewatering building.
   f. Dryer building.

Labor Availability

1. Assumed adequate availability of construction labor, across all trades. This should be evaluated as the design progresses for current market conditions. The airport expansion project and prison expansion project may affect labor resources on the WRF project. No adjustment to the estimate has been made at this time.

Contracting Strategy

1. The Construction Contact will be a CM At Risk contract, with the Guaranteed Construction amount developed at a 90 percent design level.
2. The phasing of construction packages has not been flushed out at the time of the estimate. However, it is anticipated that the Dewatering Building maybe the first contract construction package. The second construction package could be the Headworks, Grit Screening, Influent Pump Station, Influent Junction Boxes, Influent Meter Vault and Demolition of Existing Drying Beds.
3. The final construction phasing schedule would be developed at the GMP development.

13. Key Project Quantities

The following are overall plant wide key project quantities, summary information:

Facility Name	Concrete CY	Earthwork Excavation CY	Excavation Depth Ft	Sheeting and Shoring SF	Dewatering MO	Buried Pipe LF	Process Pipe LF
Sitework - Imported 15' Clean Fill		880,000					
Yard Piping		80,505	9	147,200	9	28,171	
Influent Pipeline - Twin 60" Dia - 3,600 LF		52,799	12	21,600	2	7,200	
Influent Pump Station & Junction Boxes - Off-site	8,193		32	64,973	33	875	880
Influent Meter Vault	309	1,900	34	9,900	5		
Influent Pump Station Odor Control Pad - Off-site	217	575	2				50
Headworks - On-Site	2,503	15,400	37	24,696	12	175	700
Grit Basin Facility - On-Site	2,111	10,900	13	18,414	10		600
Headworks - Odor Control Pad - On-site	217	575	2				300
Primary Effluent Splitter Box	391	2,500	17	6,160	4		
Primary Influent Splitter Box	391	2,500	17	6,160	4		
Bioreactor Splitter Box	391	2,500	17	6,160	4		
Primary Sludge Pump Station	308	3,250	16	5,796	4		584
Primary Clarifiers - 4 EA	10,920	63,500	12			460	
Primary Scum Pump Station		225	9			20	50
Secondary Scum Pump Station		225	9			20	50
Plant Drain Pump Station		225	9			20	50
Bioreactors	38,789	289,800	31	79,376	18		6,752
Secondary Clarifiers - 4 EA	17,607	82,100	12			1,200	
Return Activated Sludge Pump Station	673	3,600	8				1,235
Return Activated Sludge Spitter Box	441	3,300	23	6,750	6		16
Blower Building	1,244	5,700	7				2,925
Chemical Building	623	2,800	9				1,200
UV Disinfection Facility	85						
Effluent Parshall Flume - Flow Meter	595	4,100	21	13,272	6		
CHP Building	406	2,200	8				800
Utility Water Pump Station	40						250
Post Aeration Digestion Tank	1,587	13,900	32	15,523	6		
Post Aeration Digestion Mechanical Building	564	3,100	7				2,240
Dewatering Building	2,142	6,100	9			500	2,500
Dryer Building	2,888	6,600	10				1,000
Plant Generator - 6 EA	1,167	850	5				
OVERALL PLANT - TOTALS	**94,801**	**1,541,729**	**425**	**425,980**	**123**	**38,641**	**22,182**

14. Allowances

The estimate includes allowances for known work that is not sufficiently detailed at this time:

- Bypass pumping, tie-in connections and temporary facilities
- Yard Piping – site wide – Allowance for well point dewatering – 9 months.
- Miscellaneous metals allowances
- Interior painting allowance
- Toilet rooms allowance at Headworks
- Stormwater allowance
- Natural gas allowance
- Dryer exhaust system allowance
- Administration Building – 10,000 SF - $550/SF direct cost – Single story, includes office space, reception, conference rooms, training rooms, and break rooms.

- Operations Building – 20,000 SF - $250/SF direct cost – Single story, includes office space, conference rooms, training rooms, maintenance space, storage, operations room and operations laboratory.

15. Excluded Costs

The cost estimate excludes the following costs:

- Phase 2 improvements are not included in the construction cost estimate.
- Demolition of existing influent pump station is not included in this cost estimate.
- Demolition of existing screening facility is not included in this cost estimate.
- Demolition of existing CHP building is not included in this cost estimate.
- Demolition of existing administration building is not included in this cost estimate.
- Existing Sludge Ponds - Assumed SLC staff will removal and clean out all existing sludge and sludge water prior to contractor demolishing the sludge drying beds. Excluded this work.
- Replacement of any existing process equipment with new equipment is not included.
- Concrete or structural repair of existing structures are not included.
- Pile Foundations or Soil Treatment is not included in the cost estimate.
- Plantwide automation integration is excluded.
- Wetland improvement and mitigation items are excluded.
- Concrete Curb and Gutter is excluded.
- New security or chain-link fence is excluded.
- Open Space improvements are excluded.
- Stormwater ponds or bioretention ponds are excluded.
- Landscaping costs are excluded.
- Imported fill for phase 2 facilities is excluded.
- The cost for to incorporate "Envision" guidelines for incorporate principles for sustainable civil infrastructure have not been included in this cost estimate.
- Utility Power Source or feed into the plant has been excluded from this estimate.
- Labor shortage of resources is excluded.
- State Sale Tax Exemption has not been included in this estimate.
- Non-construction or soft costs for design, services during construction, land, legal and owner administration costs
- Material Adjustment allowances above and beyond what is included at the time of the cost estimate

16. Reference Documents

This cost estimate is based upon Water Works 15% Pre-Design Drawings and Design Report, dated August 2017.

N

0 75 150 300

SCALE IN FEET

KEYNOTES

1 WETLANDS
2 ADMINISTRATION BUILDING
3 EFFLUENT HEAT RECOVERY FACILITY
4 TERTIARY FILTRATION FACILITY
5 DISINFECTION FACILITY
6 EQUIPMENT STORAGE BUILDING
7 SECONDARY CLARIFICATION FACILITY
8 ADMINISTRATION BUILDING (EXISTING)
9 OUTFALL
10 BIOLOGICAL NUTRIENT REMOVAL FACILITY
11 OPERATIONS & MAINTENANCE BUILDING
12 WASTE ACTIVATED SLUDGE GRAVITY THICKENING FACILITY (EXISTING)
13 WASTE ACTIVATED SLUDGE MECHANICAL THICKENING FACILITY (EXISTING)
14 COMBINED HEAT & POWER FACILITY (EXISTING)
15 COUNTY PUMPS 1-4
16 SLUDGE STORAGE PAD
17 BLOWER BUILDING
18 PRIMARY CLARIFICATION FACILITY
19 THERMAL DRYING FACILITY
20 DEWATERING FACILITY
21 COMBINED HEAT & POWER FACILITY
22 DIGESTION FACILITY (EXISTING)
23 RESOURCE RECOVERY FACILITY
24 WEST MAINTENANCE (EXISTING)
25 HEADWORKS FACILITY
26 SEPTAGE RECEIVING STATION
27 INFLUENT PUMP STATION
28 BIOLOGICAL NUTRIENT REMOVAL TRAINING FACILITY
29 STAND-BY POWER
30 ELECTRICAL SUBSTATION
31 HAULED WASTE RECEIVING STATION
32 STOREHOUSE
33 CHEMICAL STORAGE FACILITY
34 CONSTRUCTION STAGING AREA

LEGEND

NON-PROCESS FACILITIES NEW / EXISTING

LIQUID STREAM FACILITIES NEW / EXISTING

SOLIDS STREAM FACILITIES NEW / EXISTING

FUTURE FACILITIES

KEY PLAN

SCALE: 1" = 100'

VERIFY SCALE
BAR IS ONE INCH ON ORIGINAL DRAWING

DESIGNED BY:
DRAWN BY:
CHECKED BY:
APPROVED BY:
DATE:
EWO NO:
ACCOUNT NO:

REVISIONS

NO. DATE MADE BY AUTH BY

SALT LAKE CITY DEPARTMENT OF PUBLIC UTILITIES
WATER RECLAMATION FACILITY UPGRADE

OVERALL SITE PLAN

PRELIMINARY
NOT FOR CONSTRUCTION

DRAWING No
XX-010-C102

SHEET ___ OF ___

Exhibit C

Estimated Design and Construction costs and rate scenarios for new WRF from 2019-2025, as a component of overall Public Utilities Sewer Planning Budget

i. Scenario 1 – Revenue Bonds and Rate Increases
ii. Scenario 2 – Federal Water Infrastructure Finance Improvement Act (WIFIA) Loan and Rate Increases

SEWER UTILITY
Planning Budget
FY20 Budget
and FY2020-2026 Forecast

+18%,20%,25%,25%,10%,10% Rate Increases
$0 in WIFIA Funds
$523M in Bonds,$55M,$107M,$187M,$138M,$69M,$17M
New Debt Pmts $109M FY 20-26
$528M New WRF in CIP

	ACTUAL YEAR 2017-2018	PROJECTED YEAR 2018-2019	BUDGET YEAR 2019-2020	BUDGET YEAR 2020-2021	BUDGET YEAR 2021-2022	BUDGET YEAR 2022-2023	BUDGET YEAR 2023-24	BUDGET YEAR 2024-25	BUDGET YEAR 2025-26
SEWER SALES	$33,620,751	$37,677,666	$44,460,000	$53,733,000	$67,642,000	$85,148,000	$94,317,000	$104,468,000	$115,705,000
OTHER INCOME	662,733	255,000	255,000	255,000	255,000	255,000	255,000	255,000	255,000
INTEREST INCOME	1,579,221	1,052,000	604,000	21,000	21,000	23,000	1,090,000	29,000	30,000
OPERATING INCOME	35,862,705	38,984,666	45,319,000	54,009,000	67,918,000	85,426,000	95,662,000	104,752,000	115,990,000
NEW PLANT O&M COSTS			0	0		(250,000)	(252,500)	(255,025)	(257,575)
OPERATING EXPENSES	(15,354,771)	(19,425,617)	(21,024,164)	(21,780,388)	(22,448,209)	(23,138,679)	(23,852,612)	(24,375,034)	(24,862,535)
NET INCOME EXCLUDING DEP.	20,507,934	19,559,049	24,294,836	32,228,612	45,469,791	62,037,321	71,556,888	80,121,941	90,869,890
IMPACT FEES	971,344	700,000	700,000	724,500	749,858	776,103	803,267	831,381	860,479
STATE LOAN (NWQ)	8,500,000								
SHORT TERM FINANCING PROCEEDS									
WIFIA LOAN									
NET BOND PROCEEDS	0		55,000,000	106,000,000	182,000,000	125,000,000	55,000,000		
ISSUE COSTS (PROCEEDS)			307,000	592,000	1,016,000	698,000	307,000	0	0
ISSUE COSTS (EXP)			(307,000)	(592,000)	(1,016,000)	(698,000)	(307,000)	0	0
OTHER CONTRIBUTIONS	978,525	2,020,000	2,020,000	2,020,000	720,000	520,000	520,000	520,000	520,000
CAPITAL OUTLAY	(847,714)	(1,302,569)	(8,694,000)	(823,000)	(823,000)	(823,000)	(823,000)	(823,000)	(823,000)
STATE LOAN DEBT REPAYMENT			(6,375,000)	(2,125,000)					
NEW DEBT SERVICE		0	(719,000)	(3,632,000)	(9,266,000)	(16,583,000)	(22,553,000)	(26,528,000)	(30,109,000)
DEBT SERVICE	(5,561,477)	(6,050,603)	(6,055,000)	(8,574,000)	(8,560,000)	(8,561,000)	(8,935,850)	(8,561,000)	(8,561,000)
OTHER INCOME & EXPENSE	4,040,678	(4,633,172)	35,877,000	93,590,500	164,820,858	100,329,103	24,011,417	(34,560,619)	(38,112,521)
NET FOR CAPITAL	24,548,612	14,925,877	60,171,836	125,819,112	210,290,649	162,366,424	95,568,305	45,561,322	52,757,369
CAPITAL IMPROVEMENTS	$ (33,243,806)	$ (60,892,051)	$ (98,370,500)	(125,728,000)	(210,160,000)	(162,630,000)	(94,660,000)	(45,480,000)	(30,321,000)
NEW WRF IN CIP			$ (54,700,000)	(82,910,000)	(175,360,000)	(132,770,000)	(65,030,000)	(13,050,000)	(4,310,000)
CASH INCREASE/(DECREASE)	(8,695,194)	(45,966,174)	(38,198,664)	91,112	130,649	(263,576)	908,305	81,322	22,436,369
		0							
BEGINING CASH BALANCE	94,916,245	86,221,051	40,254,877	2,056,213	2,147,325	2,277,974	2,014,398	2,922,703	3,004,025
CASH INCREASE/(DECREASE)	(8,695,194)	(45,966,174)	(38,198,664)	91,112	130,649	(263,576)	908,305	81,322	22,436,369
ENDING BALANCES	**86,221,051**	**40,254,877**	**2,056,213**	**$2,147,325**	**$2,277,974**	**$2,014,398**	**$2,922,703**	**$3,004,025**	**$25,440,394**
RESTRICTED/RESERVED	**(10,789,378)**								
AVAILABLE ENDING BALANCE	**$75,431,673**	**$40,254,877**	**$2,056,213**	**$2,147,325**	**$2,277,974**	**$2,014,398**	**$2,922,703**	**$3,004,025**	**$25,440,394**
RATE CHANGE	30%	15%	18%	20%	25%	25%	10%	10%	10%
Cash Reserve Ratio	**562%**	**207%**	**10%**	**10%**	**10%**	**9%**	**12%**	**12%**	**101%**
Debt Service Coverage	**3.69**	**3.23**	**1.85**	**2.25**	**2.55**	**2.47**	**2.27**	**2.28**	**2.35**
DEBT SERVICE % OF GROSS OPERATING REVENUE	16%	16%	15%	23%	26%	29%	33%	33%	33%
MONTHLY RESIDENTIAL UTILITY BILL AT 4 CCF	10.60	12.16	14.68	17.62	22.03	27.54	30.29	33.32	36.65
MONTHLY RESIDENTIAL UTILITY BILL AT 8 CCF	21.20	24.32	29.36	35.23	44.04	55.05	60.56	66.62	73.28

SEWER UTILITY
Planning Budget
FY20 Budget
and FY2020-2026 Forecast

+18%,18%,18%,15%,10%,10% Rate Increases
$259M in WIFIA Funds
$283M in Bonds,$55M,$39M,$97M,$65M $27M
New Debt Pmts $45M FY 20-26
$528M New WRF in CIP

	ACTUAL YEAR 2017-2018	PROJECTED YEAR 2018-2019	BUDGET YEAR 2019-2020	BUDGET YEAR 2020-2021	BUDGET YEAR 2021-2022	BUDGET YEAR 2022-2023	BUDGET YEAR 2023-24	BUDGET YEAR 2024-25	BUDGET YEAR 2025-26
SEWER SALES	$33,620,751	37,677,666	44,460,000	$52,838,000	$62,791,000	$72,718,000	$80,548,000	$89,216,000	$98,812,000
OTHER INCOME	662,733	255,000	255,000	255,000	255,000	255,000	255,000	255,000	255,000
INTEREST INCOME	1,579,221	1,052,000	604,000	23,000	29,000	31,000	30,000	28,000	62,000
OPERATING INCOME	35,862,705	38,984,666	45,319,000	53,116,000	63,075,000	73,004,000	80,833,000	89,499,000	99,129,000
NEW PLANT O&M COSTS			0	0		(250,000)	(252,500)	(255,025)	(257,575)
OPERATING EXPENSES	(15,354,771)	(19,425,617)	(21,024,164)	(21,780,388)	(22,448,209)	(23,138,679)	(23,852,612)	(24,375,034)	(24,862,535)
NET INCOME EXCLUDING DEP.	20,507,934	19,559,049	24,294,836	31,335,612	40,626,791	49,615,321	56,727,888	64,868,941	74,008,890
IMPACT FEES	971,344	700,000	700,000	724,500	749,858	776,103	803,267	831,381	860,479
STATE LOAN (NWQ)	8,500,000								
SHORT TERM FINANCING PROCEEDS									
WIFIA LOAN				67,429,000	85,926,000	65,057,000	31,865,000	6,395,000	2,112,000
NET BOND PROCEEDS			55,000,000	39,000,000	97,000,000	65,000,000	27,000,000		
ISSUE COSTS (PROCEEDS)			307,000	218,000	542,000	363,000	151,000	0	0
ISSUE COSTS (EXP)			(307,000)	(218,000)	(542,000)	(363,000)	(151,000)	0	0
OTHER CONTRIBUTIONS	978,525	2,020,000	2,020,000	2,020,000	720,000	520,000	520,000	520,000	520,000
CAPITAL OUTLAY	(847,714)	(1,302,569)	(8,694,000)	(823,000)	(823,000)	(823,000)	(823,000)	(823,000)	(823,000)
STATE LOAN DEBT REPAYMENT			(6,375,000)	(2,125,000)					
NEW DEBT SERVICE		0	(719,000)	(2,700,000)	(5,216,000)	(9,091,000)	(12,731,000)	(14,415,000)	(16,324,000)
DEBT SERVICE	(5,561,477)	(6,050,603)	(6,055,000)	(8,574,000)	(8,560,000)	(8,561,000)	(8,935,850)	(8,561,000)	(8,561,000)
OTHER INCOME & EXPENSE	4,040,678	(4,633,172)	35,877,000	94,951,500	169,796,858	112,878,103	37,698,417	(16,052,619)	(22,215,521)
NET FOR CAPITAL	24,548,612	14,925,877	60,171,836	126,287,112	210,423,649	162,493,424	94,426,305	48,816,322	51,793,369
CAPITAL IMPROVEMENTS	$ (33,243,806)	(60,892,051)	(98,370,500)	(125,728,000)	(210,160,000)	(162,630,000)	(94,660,000)	(45,480,000)	(30,321,000)
NEW WRF IN CIP			(54,700,000)	(82,910,000)	(175,360,000)	(132,770,000)	(65,030,000)	(13,050,000)	(4,310,000)
CASH INCREASE/(DECREASE)	(8,695,194)	(45,966,174)	(38,198,664)	559,112	263,649	(136,576)	(233,695)	3,336,322	21,472,369
		0							
BEGINING CASH BALANCE	94,916,245	86,221,051	40,254,877	2,056,213	2,615,325	2,878,974	2,742,398	2,508,703	5,845,025
CASH INCREASE/(DECREASE)	(8,695,194)	(45,966,174)	(38,198,664)	559,112	263,649	(136,576)	(233,695)	3,336,322	21,472,369
ENDING BALANCES	**86,221,051**	**40,254,877**	**2,056,213**	**$2,615,325**	**$2,878,974**	**$2,742,398**	**$2,508,703**	**$5,845,025**	**$27,317,394**
RESTRICTED/RESERVED	**(10,789,378)**								
AVAILABLE ENDING BALANCE	**$75,431,673**	**40,254,877**	**2,056,213**	**$2,615,325**	**$2,878,974**	**$2,742,398**	**$2,508,703**	**$5,845,025**	**$27,317,394**
RATE CHANGE	30%	15%	18%	18%	18%	15%	10%	10%	10%
Cash Reserve Ratio	**562%**	**207%**	**10%**	**12%**	**13%**	**12%**	**10%**	**24%**	**109%**
Debt Service Coverage	**3.69**	**3.23**	**1.85**	**2.34**	**2.95**	**2.81**	**2.62**	**2.82**	**2.97**
DEBT SERVICE % OF GROSS OPERATING REVENUE	16%	16%	15%	21%	22%	24%	27%	26%	25%
MONTHLY RESIDENTIAL UTILITY BILL AT 4 CCF	10.60	12.16	14.68	17.32	20.44	23.51	25.86	28.45	31.30
MONTHLY RESIDENTIAL UTILITY BILL AT 8 CCF	21.20	24.32	29.36	34.64	40.88	47.01	51.71	56.88	62.57

Exhibit D

WIFIA Fact Sheet

WIFIA PROGRAM

The WIFIA program accelerates investment in our nation's water infrastructure by providing long-term, low-cost supplemental loans for regionally and nationally significant projects. The WIFIA program was established by the Water Infrastructure Finance and Innovation Act of 2014.

ELIGIBILITY

Eligible borrowers

- Local, state, tribal, and federal government entities
- Partnerships and joint ventures
- Corporations and trusts
- Clean Water and Drinking Water State Revolving Fund (SRF) programs

WIFIA can fund development and implementation activities for eligible projects

- Wastewater conveyance and treatment projects
- Drinking water treatment and distribution projects
- Enhanced energy efficiency projects at drinking water and wastewater facilities
- Desalination, aquifer recharge, and water recycling projects
- Acquisition of property if it is integral to the project or will mitigate the environmental impact of a project
- A combination of eligible projects secured by a common security pledge or submitted under one application by an SRF program

FUNDING AVAILABILITY

EPA announces WIFIA funding availability and application process details in the Federal Register and on its website.

IMPORTANT PROGRAM FEATURES

$20 MIL — Minimum project size for large communities.

$5 MIL — Minimum project size for small communities (population of 25,000 or less).

49% — Maximum portion of eligible project costs that WIFIA can fund.

35 YEARS — Maximum final maturity date from substantial completion.

5 YEARS — Maximum time that repayment may be deferred after substantial completion of the project.

% — Interest rate will be equal or greater to the US Treasury rate of a similar maturity.

Projects must be creditworthy.

NEPA, Davis-Bacon, American Iron and Steel, and all federal cross-cutter provisions apply.

EPA

STAY IN TOUCH

WEBSITE: www.epa.gov/wifia

EMAIL: wifia@epa.gov

Sign-up to receive announcements about the WIFIA program at https://tinyurl.com/wifianews

November 2016

EPA-830-F-16-003

WIFIA PROGRAM

The Water Infrastructure Finance and Innovation Act (WIFIA) program accelerates investment in our nation's water infrastructure by providing long-term, low-cost supplemental loans for nationally and regionally significant projects. Borrowers benefit from receiving low, fixed interest rate loans with flexible financial terms.

WIFIA LOANS OFFER A LOW, FIXED INTEREST RATE

A SINGLE FIXED RATE IS ESTABLISHED AT CLOSING. A borrower may receive multiple disbursements over several years at the same fixed interest rate.

RATE IS EQUAL TO THE US TREASURY RATE OF A SIMILAR MATURITY. The WIFIA program sets its interest rate based on the U.S. Treasury rate on the date of loan closing. The rate is calculated using the weighted average (WAL) life of the loan rather than the loan maturity date. The WAL is generally shorter than the loan's actual length resulting in a lower interest rate.

RATE IS NOT IMPACTED BY BORROWER'S CREDIT OR LOAN STRUCTURE. All borrowers benefit from the AAA Treasury rate, regardless of whether they are rated AA or BBB. The WIFIA program does not charge a higher rate for flexible financial terms.

WIFIA LOANS PROVIDE FLEXIBLE FINANCIAL TERMS

CUSTOMIZED REPAYMENT SCHEDULES. Borrowers can customize their repayments to match their anticipated revenues and expenses for the life of the loan. This flexibility provides borrowers with the time they may need to phase in rate increases to generate revenue to repay the loan.

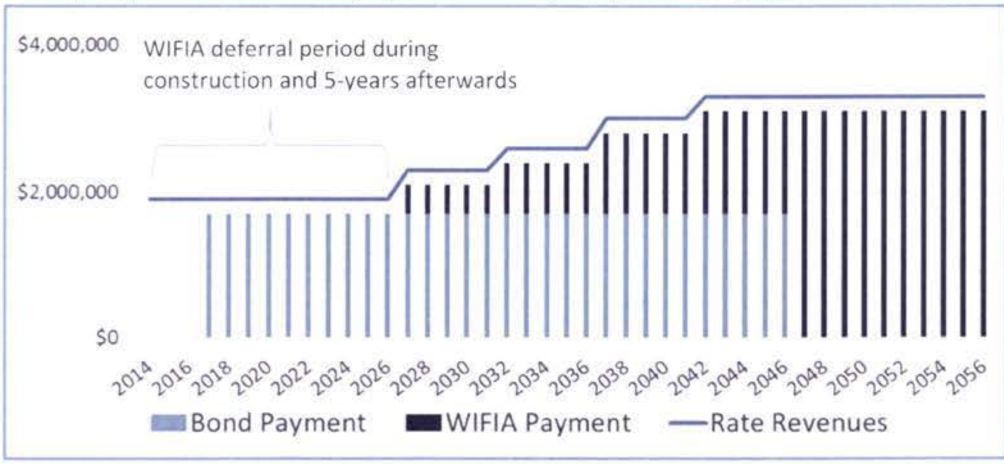
LONG REPAYMENT PERIOD. WIFIA loans may have a length of up to 35 years after substantial completion, allowing payment amounts to be smaller throughout the life of the loan.

DEFERRED PAYMENTS. Payments may be deferred up to 5 years after the project's substantial completion.

SUBORDINATION. Under certain circumstances, WIFIA may take a subordinate position in payment priority, increasing coverage ratios for senior bond holders.

WIFIA LOANS CAN BE COMBINED WITH VARIOUS FUNDING SOURCES. WIFIA loans can be combined with private equity, revenue bonds, corporate debt, grants, and State Revolving Fund (SRF) loans.

Example of a customized debt repayment structure for a $100 million project



WIFIA loan's flexible repayment schedule allows for rate increases to be phased in over a longer period of time.

EPA

WEBSITE: www.epa.gov/wifia
EMAIL: wifia@epa.gov
ANNOUNCEMENTS: Sign-up at https://tinyurl.com/wifianews

Exhibit E

Official correspondence between Salt Lake City Department of Public Utilities and Utah Department of Environmental Quality establishing a permit variance for Technology-Based Phosphorus Effluent Limits, dated November 6, 2017 through March 21, 2019

State of Utah
GARY R. HERBERT
Governor
SPENCER J. COX
Lieutenant Governor

Department of
Environmental Quality
Alan Matheson
Executive Director
DIVISION OF WATER QUALITY
Erica Brown Gaddis, PhD
Director

March 21, 2019

Laura Briefer
Director of Department of Public Utilities
Salt Lake City Corporation
1530 South West Temple
Salt Lake City, Utah 84115

Subject: **Response to Request for Change in Condition for Variance to Technology-Based Phosphorus Effluent Limitations (TBPEL) UPDES Permit No. UT0021725**

Dear Ms. Briefer,

Part 12.d. of the 2018 Salt Lake City Permit variance for technology-based phosphorus effluent limits (SLC Variance for TBPEL) defines variance milestones including the submission of a City Council resolution supporting pursuit of a facility upgrade. SLC Public Utilities requested the due date for Part 12.d. be extended from May 1, 2019 to July 1, 2019 in a letter dated March 13, 2019 (DWQ-2019-002805). This request is based on the timing of the Salt Lake City Mayor's budget release date and City Council meetings. The request for extension is approved. The requirements of Part 12.d. are hereby altered to:

d. By no later than ~~May 1~~ July 1, 2019, SLC Public Utilities shall submit to DWQ:

i. A formal letter committing to the selected biological phosphorus removal technology (full BNR or the BNR facility operated as EBPR) including project schedule, and budget analysis (including project costs and funding information).

ii. A City Council resolution supporting the pursuit of the facility upgrade to the selected biological phosphorus removal technology. The resolution shall include the approximate budget for the facility upgrade.

iii. A proposed schedule of when completed design plans for permitting will be submitted to DWQ.

The submission of these 3 items by no later than July 1, 2019 will be considered in full compliance with Part 12.d. of the SLC Variance for TBPEL.

DWQ does not view this modification as a substantive change or a re-visitation of the variance as no rationale of the justification is being reevaluated. The final TBPEL compliance date remains the same; as such this due date alteration will not be public noticed.

Should you have any questions regarding this matter, please contact Mr. Ken Hoffman at (801) 536-4313 (kenhoffman@utah.gov) of my staff.

Sincerely,

Erica B Gaddis

Erica Brown Gaddis, PhD
Director

EBG/KH/blj

DWQ-2019-002804

JACQUELINE M. BISKUPSKI
Mayor

DEPARTMENT OF PUBLIC UTILITIES

March 13, 2019

Utah Department of Environmental Quality
Division of Water Quality
PO Box 144870
Salt Lake City, UT 84114—4870

Attention: Erica Gaddis, Director

Request for Change in Condition for Variance to Technology-Based Phosphorus Effluent Limitations (TBPEL); UPDES Permit No. UT0021725

Dear Director Gaddis:

On May 29, 2018, Utah Department of Environmental Quality (UDEQ) transmitted its approval of a variance to the TBPEL permit variance issued for Salt Lake City Department of Public Utilities (SLCDPU) (UPDES Permit No. UT0021725). One condition of the variance states that by May 1, 2019, *"Salt Lake City must submit a City Council resolution supporting the pursuit of the facility upgrade to the selected biological phosphorus removal technology. The resolution shall include the approximate budget for the facility upgrade."*

As we have been preparing materials for our City Council to consider along with this resolution, we realized that in order to meet the May 1, 2019 deadline for the resolution, SLCDPU would need to request a City Council resolution approving the approximate budget for the facility reconstruction prior to the Mayor and Council's completion of the City's overall budget process for Fiscal Year (FY) 2020. This is especially relevant in that portions of SLCDPU's proposed FY 2020 budget include revenue bonding and design costs associated with the facility reconstruction.

Since our FY 2020 budget year begins on July 1, 2019, and our City Council generally approves the City's overall budget in June, we are requesting that that we provide your office with the required City Council resolution by July 1, 2019. This condition change will be in better alignment with the sequence of Salt Lake City's municipal budgeting process.

Thank you for taking the time to consider this request. SLCDPU is committed to the reconstruction and upgrade of our Water Reclamation Facility and meeting the January 1, 2025 TBPEL compliance date. Please do not hesitate to contact me with any questions or concerns at 801.483.6741, or laura.briefer@slcgov.com.

Sincerely,

Laura Briefer
Director

cc: Jesse Stewart, Deputy Director
Rusty Vetter, SLC Attorney's Office

State of Utah
GARY R. HERBERT
Governor

SPENCER J. COX
Lieutenant Governor

Department of
Environmental Quality

Alan Matheson
Executive Director

DIVISION OF WATER QUALITY
Erica Brown Gaddis, Ph.D.
Director

May 29, 2018

Laura Briefer
Director of Department of Public Utilities
Salt Lake City Corporation
1530 South West Temple
Salt Lake City, Utah 84115

Dear Ms. Briefer,

Subject: Approval of Variance to Technology-based Phosphorus Effluent Limitations (TBPEL) under R317-1-3.3.C.e.

We have completed our review of your "Technology-based Phosphorus Effluent Limits (TBPEL) Rule Compliance Postponement Request", that was submitted in regard to the Salt Lake City Department of Public Utilities (SLC Public Utilities) wastewater treatment plant. The request was submitted as a proposed demonstration of due diligence variance requirements of R317-1-3.3.C.e. The request was submitted by SLC Public Utilities, signed by Laura Briefer, and received on November 9, 2017 (DWQ-2017-011173). The request included documentation of the following items:

1. Salt Lake City Department of Public Utilities Projects at the SLCWRF: Nutrient Project Pre-Design Report, Waterworks Engineers (August, 2017).

2. Sewer Utility Capital Improvement Plan (CIP) Budget – Five Year Projected Budget 2018-2022. (by reference)

3. Clarification of Salt Lake City Department of Public Utilities application for a variance from R317-1-3.3, Technology-Based Limits for Controlling Phosphorus Pollution. (March 26, 2018)

These documents demonstrate that SLC Public Utilities is committed to, and diligently pursuing design, financing, and planning for construction of treatment works necessary to meet the TBPEL. These documents further demonstrate that SLC Public Utilities will be unable to complete facilities improvements necessary to comply with the TBPEL by the January 1, 2020 deadline. As

a result, the attached permit variance to the TBPEL under R317-1-3.3.C.e is hereby issued subject to the following conditions:

1. SLC Public Utilities shall comply with the requirements of the attached Permit Variance for Technology-Based Phosphorus Effluent Limits.

2. Nothing in this concept approval letter relieves SLC Public Utilities from compliance with their current UPDES permit requirements.

Should you have any questions, please contact either Ken Hoffman at (801) 536-4313 (kenhoffman@utah.gov) or Jeff Studenka at (801) 536-4395 (jstudenka@utah.gov) of my staff.

Sincerely,

Erica B. Gaddis

Erica Brown Gaddis, PhD
Director

EBG/KH/JS/blj

Enclosure (1): 1. Permit Variance for Technology-Based Phosphorus Effluent Limits (DWQ-2018-003574)

DWQ-2018-003572

UTAH DIVISION OF WATER QUALITY

IN THE MATTER OF **Salt Lake City Department of Public Works** **1530 South West Temple** **Salt Lake City, Utah 84115** **UPDES PERMIT NO. UT0021725**	**PERMIT VARIANCE FOR TECHNOLOGY-BASED PHOSPHORUS EFFLUENT LIMITS**

BACKGROUND

1. Salt Lake City Department of Public Utilities' ("SLC Public Utilities") wastewater treatment plant in Salt Lake City, Utah (the "Facility") provides wastewater services within Salt Lake County.

2. SLC Public Utilities' operations at the Facility are undertaken subject to UPDES Discharge Permit No. UT0021725 ("Permit").

3. The Facility is required to achieve technology-based phosphorus effluent limits ("TBPEL") on or before January 1, 2020, unless a variance is granted. *See* UAC R317-1-3.3.

4. SLC Public Utilities submitted a variance request, dated November 6, 2017 to the Utah Division of Water Quality ("DWQ"), seeking an extension of the TBPEL implementation date (the "Variance Request."). The Variance Request is based on the fact that SLC Public Utilities is in the process of designing and constructing improvements to the Facility to meet TBPEL requirements, however such improvements cannot be completed prior to January 1, 2020, despite SLC Public Utilities' diligence.

5. SLC Public Utilities submitted a clarification to their variance request, dated March 26, 2018 to the DWQ. This clarification formally replied to items of question by DWQ concerning their variance request and potential milestones for variance approval.

6. Utah law provides that DWQ may grant a variance as to the implementation date for compliance with the TBPEL in the event that the operator demonstrates due diligence toward construction of a treatment facility designed to meet TBPEL, provided that such compliance date shall not be later than January 1, 2025. *See* UAC R317-1-3.3.C.e.

7. The Director of DWQ has determined that SLC Public Utilities has met its burden to show diligence within the meaning of the UAC R317-1-3.3 and that a variance is appropriate, subject to the limitations and conditions provided herein.

AUTHORITY

8. The Director of DWQ has authority to grant a variance as to the implementation deadline for TBPEL pursuant to UAC R317-1-3.3 and the corresponding provisions of the Utah Water Quality Act.

9. The State of Utah administers the Utah Pollution Discharge Elimination System (UPDES) permit program under the Utah Water Quality Act.

DUE DILIGENCE - FINDINGS

10. The Variance Request included the following submissions, among others:

a. Salt Lake City Department of Public Utilities Projects at the SLCWRF: Nutrient Project Pre-Design Report, Waterworks Engineers (August, 2017).

b. Sewer Utility Capital Improvement Plan (CIP) Budget – Five Year Projected Budget 2018-2022. (by reference)

c. Clarification of Salt Lake City Department of Public Utilities application for a variance from R317-1-3.3, Technology-Based Limits for Controlling Phosphorus Pollution. (March 26, 2018)

11. Based on the foregoing submissions, the Director has determined that SLC Public Utilities has established due diligence toward construction of Biological Phosphorus Removal treatment facility upgrade designed to meet TBPEL, within the meaning of UAC R317-1-3.3.C.e.

VARIANCE

12. The Director hereby grants SLC Public Utilities a variance as to the compliance date to achieve TBPEL, until the time that its facility improvements described in the Variance Request are operational; subject to the following conditions:

a. This variance does not extend beyond January 1, 2025. SLC Public Utilities must comply with all TBPEL requirements by that date.

b. Pursuant to UAC R317-1-3.3.C.2, this variance is subject to re-evaluation in the event that there is any substantive change in the facility design or construction plans provided in the Variance Request. SLC Public Utilities must provide timely notice to DWQ of any such substantive changes.

c. By no later than January 31, 2022, SLC Public Utilities shall submit to DWQ an approvable complete construction permit application per UAC R317-3 for construction permitting of a facility to biologically remove phosphorus to 1.0 mg/L or less.

d. By no later than May 1, 2019, SLC Public Utilities shall submit to DWQ:

   i. A formal letter committing to the selected biological phosphorus removal technology (full BNR or the BNR facility operated as EBPR) including project schedule, and budget analysis (including project costs and funding information).

   ii. A City Council resolution supporting the pursuit of the facility upgrade to the selected biological phosphorus removal technology. The resolution shall include the approximate budget for the facility upgrade.

   iii. A proposed schedule of when completed design plans for permitting will be submitted to DWQ.

e. Beginning no later than July 1, 2019, and for every year thereafter while this variance is in effect, SLC Public Utilities agrees to submit to DWQ an annual report relating to its phosphorus discharges (the "Annual Report"). The scope of the Annual Report shall include descriptions of all projects and work necessary, in reasonable detail, to achieve compliance with the TBPEL rule. The Annual Report will provide a summary of progress and milestones achieved in all construction, study, funding, planning, and design projects during the previous reporting period, projected progress and milestones scheduled to be completed during the following reporting period, and if the project(s) are on schedule. The Annual Report will also provide information on effluent phosphorus concentrations to determine SLC Public Utilities' compliance with Parts 11.e. and 11.f. of this variance, noted below.

   i. The Annual Report must specifically state the economic benefit per year SLC Public Utilities will receive from January 1 to December 31 of the coming year from this due diligence variance for not treating total phosphorus to 1.0 mg/L.

f. No total phosphorus effluent limitation will be added to the Permit before January 1, 2020.

g. Effective January 1, 2020, DWQ will impose the following interim effluent limitation under the Permit: total phosphorus annual average effluent limitation of 3.8 mg/L.

h. Upset Conditions from Part VI.H of UPDES Permit No. UT0021725

i. Effect of an upset. An upset constitutes an affirmative defense to an action brought for noncompliance with technology based permit effluent limitations if the requirements of paragraph 2 (ii) of this section are met. Director's administrative determination regarding a claim of upset cannot be judiciously challenged by the permittee until such time as an action is initiated for noncompliance.

ii. Conditions necessary for a demonstration of upset. A permittee who wishes to establish the affirmative defense of upset shall demonstrate, through properly signed, contemporaneous operating logs, or other relevant evidence that:

1. An upset occurred and that the permittee can identify the cause(s) of the upset;

2. The permitted facility was at the time being properly operated;

3. The permittee submitted notice of the upset as required under *Part V.H, Twenty-four Hour Notice of Noncompliance Reporting* of UPDES Permit No. UT0021725; and,

4. The permittee complied with any remedial measures required under *Part VI.D, Duty to Mitigate* of UPDES Permit No. UT0021725.

iii. Burden of proof. In any enforcement proceeding, the permittee seeking to establish the occurrence of an upset has the burden of proof.

Erica B. Gaddis

Date: 5/29/18

Erica Brown Gaddis, PhD
Director
Utah Division of Water Quality

DWQ-2018-003574

State of Utah

GARY R. HERBERT
Governor

SPENCER J. COX
Lieutenant Governor

Department of
Environmental Quality

Alan Matheson
Executive Director

DIVISION OF WATER QUALITY
Erica Brown Gaddis, PhD
Director

APR 17 2018

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ATTENTION: Legal Advertising Department

This letter will confirm authorization to publish the attached NOTICE in The Salt Lake Tribune or Deseret News in the first available edition. Please mail the invoice and affidavit of publication to:

> Department of Environmental Quality
> Division of Water Quality
> Attn: Emily Canton
> P.O. Box 144870
> Salt Lake City, Utah 84114-4870

If there are any questions, please contact Savannah Miller at (801) 536-4316. Thank you for your assistance.

Sincerely,

M. Shelly for

Matthew Garn P.E., Manager
UPDES Surface Water Section

MG/JAS/smm

DWQ-2018-004188

State of Utah

GARY R. HERBERT
Governor

SPENCER J. COX
Lieutenant Governor

Department of
Environmental Quality

Alan Matheson
Executive Director

DIVISION OF WATER QUALITY
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Director

April 18, 2018
DIVISION OF WATER QUALITY
UTAH DEPARTMENT OF ENVIRONMENTAL QUALITY
PUBLIC NOTICE OF VARIANCE TO TBPEL IMPLEMENTATION DATE

PURPOSE OF PUBLIC NOTICE

The purpose of this public notice is to declare the State of Utah's intention to grant a variance to the implementation deadline for Technology Based Phosphorus Effluent Limit (TBPEL) compliance to Salt Lake City Wastewater Treatment Facility. Pursuant to *UAC R317-1-3.3* and corresponding provisions of the Utah Water Quality Act.

PERMIT INFORMATION

PERMITTEE NAME:	Salt Lake City Water Reclamation Facility
MAILING ADDRESS:	1530 S West Temple, Salt Lake City, UT 84114
TELEPHONE NUMBER:	(801) 483-6670
FACILITY LOCATION:	1365 West 2300 North, Salt Lake City, UT 84116
UPDES PERMIT NO.:	UT0021725
RECEIVING WATERS:	Jordan River

BACKGROUND

The Salt Lake City Water Reclamation Facility (SLC) serves the greater Salt Lake City area, including the University of Utah. SLC submitted a variance request, dated November 6, 2017 to the Utah Division of Water Quality "DWQ", seeking a variance to the TBPEL implementation date. The Variance Request is based on the fact that SLC is in the process of designing and constructing improvements to the Facility to meet TBPEL requirements, however, such improvements cannot be completed prior to January 1, 2020, despite SLC's diligence.

PUBLIC COMMENTS

Public comments are invited any time prior to the deadline of the close of business on May 18, 2018. Written public comments can be submitted to: Jeff Studenka, UPDES Surface Water Section, Utah Division of Water Quality, P.O. Box 144870, Salt Lake City, Utah 84114-4870 or by email at: jstudenka@utah.gov. After considering public comment the Utah Division of Water Quality may execute the variance, revise it or abandon it. The variance is available for public review under https://deq.utah.gov/public-notices/water-quality-public-notices. If internet access is not available, a copy may be obtained by calling Jeff Studenka at 801-536-4395.

DWQ-2018-004186

JACQUELINE M. BISKUPSKI
Mayor

DEPARTMENT OF PUBLIC UTILITIES

March 26, 2018

Utah Department of Environmental Quality
Division of Water Quality
P.O. Box 144870
Salt Lake City, UT 84114-4870
Attn: Ken Hoffman, P.E.

Subject: Clarification of Salt Lake City Department of Public Utilities application for a variance from R317-1-3.3, Technology-Based Limits for Controlling Phosphorus Pollution

Dear Mr. Hoffman:

The intent of this letter is to provide the additional information requested in your e-mail communication dated February 23, 2018 related to the Salt Lake City Department of Public Utilities (City) application requesting a five-year variance (from January 1, 2020 to January 1, 2025) for compliance with the Technology-Based Phosphorous Effluent Limit (TBPEL) of 1.0 milligram per liter (mg/L) for the Salt Lake City Water Reclamation Facility (SLCWRF), UPDES Permit UT0021725.

Based upon your response, it is our understanding that we need to provide the following items to the Division of Water Quality (DWQ) as addendum to our variance request that was submitted to the DWQ on 11/06/2017 (see attached):

1. Planning/feasibility requirement
2. Schedule
3. Specified Technology and estimated budget
4. Milestone for submission of complete designs
5. Interim phosphorus limit

Each of these items is discussed in the subsequent paragraphs. Please let us know if you need additional information than what is provided.

1. Planning/Feasibility Requirement

Per your above referenced e-mail, it is our understanding that the previously submitted SLCWRF Nutrient Project Pre-Design Report meets the planning/feasibility requirement of the variance requests.

2. Schedule

The City is selecting an engineering consulting firm to provide professional design and construction management services for the duration of our project. The selection is expected to be finalized by May 2018. The project schedule and design concept is anticipated to be finalized by May of 2019. We will provide this information to DWQ for their review and comment.

3. Specified Technology and Estimated Budget

The City is planning to design and construct facilities to provide full biological nutrient removal (BNR). The City plans to design the facilities in such a way that it can be operated to provide either enhanced biological phosphorus removal (EBPR) or full BNR. The specific process design for these facilities (e.g., MLE, Westbank) will be finalized with the selected design firm. We anticipate the design concept will be finalized by May of 2019 and presented in the form of a design report for the entire facility.

The estimated budget for this project, based on the current 15% design, is \$325 - 510 million. Please note, this budget is based on the preliminary design, and will be updated and modified during final design concept development. As stated in our initial letter requesting a variance, we offer the following of our demonstrated financial commitment to this large capital project:

- The Five Year Projected Budget for fiscal years 2018-2022 includes planned expenditures for the current fiscal year and proposed budget for out years for the necessary capital projects at the plant. Attached are proposed expenditures for the fiscal year 2018/19 with projections through 2022.
- A capital financial plan has been prepared to include the design and construction of the new facility. The financial plan includes bonding completed in 2017 (\$78 million between collections and the SLCWRF) and additional planned bonding for more than \$300 million through fiscal year 2024 for final design and construction of the facility. The projected bonding amounts may change pending refined overall project costs.
- Beginning in fiscal year 2016, the City implemented the first of several planned rate increases to raise revenue for the WRF project and account for bonding debt service. The rate increases approved by the Salt Lake City Council in fiscal years 2016, 2017, and 2018 were 8%, 12%, and 30% increases, respectively. We have presented our plan for anticipated rate increases for fiscal years 2019, 2020, 2021, and 2023 at 15%, 15%, 10%, and 8%, respectively. The projected rate increases may change pending refined project costs and bonding amounts and schedules. The Salt Lake City Mayor and Council understand the need for the SLCWRF project, and are aware of the projected rate increases and financing plan.
- The City has communicated with DWQ regarding potential funding sources through the State Revolving Fund Loan; however, additional discussion with the City's financial advisors, and with DWQ will be conducted before determining the best course of action.

4. Milestone for Submission of Complete Design

It is anticipated that this project will need to be delivered in several construction packages in order to be completed to meet the requested January 1, 2025 deadline. We would like to work with DWQ to optimize the submittal and review of these packages to ensure a complete and well-reviewed design prior to beginning construction. By May 2019, we plan to have finalized the conceptual design of the facility, which would include a design report for the entire facility, a project schedule, and a list of design/construction packages. We will work with DWQ prior to finalizing this schedule and package delivery list to plan appropriate time for submittal review and to ensure DWQ is in agreement with the review plan moving forward. In addition, we have discussed with DWQ having semi-annual project update meetings with the City, our design engineers, and DWQ staff.

5. Interim Phosphorus Limit

DWQ may propose a draft interim phosphorous effluent limit of 3.6 milligrams per liter (mg/L). This concentration is roughly equivalent to the SLCWRF effluent annual average. Although the SLCWRF is not currently specifically designed to treat phosphorous to low levels, the facility has typically removed approximately 30% of the influent phosphorous concentration. Our effluent

concentrations are directly tied to the influent phosphorous concentrations; therefore, we propose that no interim phosphorous limit is established. Rather, the SLCWRF will continue to operate with the goal of 30% reduction of influent phosphorous concentrations as our pre-treatment division continues to limit phosphorous influent concentrations.

Commitment

In summary, by May 1, 2019, the City shall submit to DWQ:

I. A formal letter committing to the selected biological phosphorus removal technology (full BNR or the BNR facility operated as EBPR) including project schedule, and budget analysis (including project costs and funding information).

II. A City Council resolution supporting the pursuit of the facility upgrade to the selected biological phosphorus removal technology. The resolution shall include the approximate budget for the facility upgrade.

III. A proposed schedule of when completed design plans for permitting will be submitted to DWQ.

IV. A commitment to operate the facility with the goal of 30% reduction of influent phosphorous concentrations while design and construction of the new SLCWRF is conducted.

In return, we request that DWQ will approve the proposed schedule and the submission of complete design plans in accordance with the approved schedule that is a requirement of this variance.

We thank you for your consideration of our application for variance and request that you contact us with any questions you may have.

Sincerely,
Jesse A. Stewart for

Laura Briefer
Director
Salt Lake City Corporation
Department of Public Utilities

cc: U.S. EPA, Region 8
Jesse Stewart, Jason Brown, Jamey West, Derek Velarde, Michelle Barry - SLCDPU
Patrick Leary, Chief of Staff, Salt Lake City Mayor's Office
Cindy Gust-Jensen, Director, Salt Lake City Council
File

Calfo, Janine

From: Stewart, Jesse
Sent: Monday, March 19, 2018 7:39 AM
To: Briefer, Laura
Subject: FW: TBPEL Variance request

This is to accompany the letter regarding the TBPEL Variance request.

Jesse

From: Ken Hoffman [mailto:kenhoffman@utah.gov]
Sent: Friday, February 23, 2018 5:01 PM
To: Stewart, Jesse <Jesse.Stewart@slcgov.com>
Subject: TBPEL Variance request

Good talking with you yesterday. You asked me to send an email to clarify potential variance milestones. The items we have asked for in a variance request has been planning/feasibility, schedule, and a governing body resolution for a project with specified technology and estimated budget. Your pre-design report covers your planning/feasibility requirement. However, it is a bit undefined on schedule and a selected technology.

In addition, to these items the draft variances approvals are including a milestone for submission of complete designs and an interim phosphorus limit. Your draft interim limit is proposed at 3.6 mg/L. This is intended as a keep doing what you're doing with no additional treatment then has occurred the past 2 years.

Milestones
Technology - on the phone you stated SLC will be going with the BNR project described in your report. So maybe you can wrap up the planning/feasibility piece with a brief letter.

Schedule - it sound like you would like to commit to supplying a schedule by the end of the year once you have your engineer on board.

Resolution - This probably again needs a little time to settle on the project, budget, timeline

Completed Plans - It seemed like you would like to include this as part of your schedule and have it determine the timeline for complete plans.

I've included some draft language at the bottom which could address each of these items.

Last, let me reiterate it is my goal to not create any new work for you but just track the good hard work you and Salt Lake City are already doing. Please let me know if you have thoughts as I'm happy to take feedback.

Thank you,
Ken
--

Ken Hoffman, P.E. | Environmental Engineer

Engineering Section

Phone: 801.536.4313

c. By no later than January 1, 2019, SLC Public Utilities shall submit to DWQ:

i. A formal letter committing to the selected biological phosphorus removal technology including project schedule and budget analysis including project costs and how the project will be funded.

ii. A resolution instructing SLC Public Utilities staff to pursue the facility upgrade to the selected biological phosphorus removal technology. The resolution shall include the approximate budget for the facility upgrade.

iii. A proposed schedule of when complete design plans for permitting will be submitted.

a) DWQ will approve the proposed schedule and the submission of complete design plans in accordance with the approved schedule will be a requirement of this variance.

State of Utah

GARY R. HERBERT
Governor

SPENCER J. COX
Lieutenant Governor

Department of
Environmental Quality

Alan Matheson
Executive Director

DIVISION OF WATER QUALITY
Erica Brown Gaddis, PhD
Director

FEB 27 2018

Laura Briefer, Director
Salt Lake City Water Reclamation Facility
1530 S West Temple
Salt Lake City, UT 84115

Dear Ms. Briefer:

Subject: UPDES Permit No. UT0021725, Salt Lake City Water Reclamation Facility, Review of Technology-Based Phosphorus Effluent Limits (TBPEL) Variance Request

The Division of Water Quality (DWQ) has received Salt Lake City Water Reclamation Facility's request for variance to the TBPEL rule (R317-1-3.3). Salt Lake City Water Reclamation Facility is requesting this variance of the condition found in R317-1-3.3.C.1.e, for due dilligence.

Ken Hoffman has been assigned to review the variance request for your facility. A fee will be assessed based on the amount of time needed to complete the review of the variance request. The fee schedule, as approved by the legislature, for Technical Review and assistance given is $90.00 per hour. It is estimated that the variance review will take between 12 and 40 hours, with an estimated cost between $1080.00 and $3600.00. Once the variance request is completed, an invoice will be sent to Salt Lake City Water Reclamation Facility.

If you have any questions regarding the variance review process, please contact Ken at kenhoffman@utah.gov or at (801) 536-4313. You may also contact Jeff Studenka at jstudenka@utah.gov or at (801) 536-4395 with questions about your UPDES permit.

Sincerely,

Erica B. Gaddis

Erica Brown Gaddis, PhD
Director
EBG:MG:KH:JS:smm

JACQUELINE M. BISKUPSKI
Mayor

DEPARTMENT OF
PUBLIC UTILITIES

November 6, 2017

Utah Department of Environmental Quality
Division of Water Quality
P.O. Box 144870
Salt Lake City, UT 84114-4870
Attn: Erica Gaddis, Director

Subject: Salt Lake City Department of Public Utilities application for a variance from R317-1-3.3, Technology-Based Limits for Controlling Phosphorus Pollution

Dear Director Gaddis:

The Salt Lake City Department of Public Utilities (SLC Public Utilities) is submitting this application requesting a five-year variance (from January 1, 2020 to January 1, 2025) for compliance with the Technology-Based Phosphorous Effluent Limit (TBPEL) of 1.0 milligram per liter (mg/L) for the Salt Lake City Water Reclamation Facility (SLC Water Reclamation Facility), UPDES Permit UT0021725. SLC Public Utilities has worked with professional environmental engineering firms and members of the research and academic community to identify appropriate fiscal and technological approaches to achieve the TBPEL, while also addressing other plant needs (e.g., replacement of aged facilities; addressing hydraulic, structural, and electrical insufficiencies; meeting sustainability objectives).

SLC Public Utilities has determined construction of a new facility capable of meeting the TBPEL is in the best interests of the public, environment, and SLC Public Utilities. Over the past two years, SLC Public Utilities has worked with consultants to prepare the pre-design for this Nutrient/Facility Upgrade project (see attached Nutrient Project Pre-Design Report).

Based on the magnitude of the project (e.g., the time required for design, and construction of the facility, and procurement of funds), SLC Public Utilities requests a five-year variance from the Utah Department of Environmental Quality (UDEQ) Division of Water Quality (DWQ) for compliance with the TBPEL. This request for a variance is per Utah Administrative Code R317-1-3.3.C.1e, which states,

> "Where the owner of a non-lagoon discharging treatment works demonstrates due diligence toward construction of a treatment facility designed to meet the TBPEL, the compliance date shall be no later than January 1, 2025."

SLC Public Utilities offers as demonstration of our due diligence, the following:

- **Nutrient Project Pre-Design Report (2017)** - This Nutrient Project Pre-Design Report (attached) provides the basis of design and pre-design for facility upgrades. In addition, SLC Public Utilities has developed and posted a Request for Qualifications (RFQ) with the

1530 South West Temple
Salt Lake City, Utah 84115

www.slcgov.com
Tel 801-483-6900 Fax 801-483-6818

Request for Proposal (RFP) for the design and construction of the facility in local newspapers and on the SciQuest website: https://solutions.sciquest.com/apps/Router/SupplierLogin?CustOrg=StateOfUtah.

- **Sewer Utility Capital Improvement Plan (CIP) Budget – Five Year Projected Budget 2018-2022** –SLC Public Utilities' 2017/2018 Annual Budget includes planned expenditures for the current fiscal year and proposed budget for out years for the necessary capital projects at the plant. In addition, SLC Public Utilities has developed a capital financial plan to include the design and construction of the new facility. The financial plan includes bonding completed in 2017 and additional planned bonding in the next two to seven years for design and construction of the facility. In addition, SLC Public Utilities has communicated with the DWQ regarding potential funding sources through the State. The budget and process has been reviewed and adopted by the Public Utilities Advisory Committee (PUAC)[1] and Mayor of Salt Lake City as well as the Salt Lake City Council.

We thank you for your consideration of our application for variance and request that you contact us with any questions you may have.

Sincerely,

Laura Briefer
Director
Salt Lake City Corporation
Department of Public Utilities

cc: U.S. EPA, Region 8
Jesse A. Stewart, Jason Brown, Dale Christensen – SLCDPU
Patrick Leary, Salt Lake City
File

Attachments:
- Nutrient Project Pre-Design Report

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[1] "The Salt Lake City Public Utilities Advisory Committee annually reviews the department's operation and maintenance budget and expenditures, examines the department's water and sewer system capital improvements program, recommends proposed legislation relating to water and sewer, and consults with the Mayor concerning water resources and sewage reclamation requirements. This committee assists the Public Utilities Director as much as possible to continue orderly development and operation of the public utilities system for the city." (http://www.slcgov.com/bc/boards-and-commissions-public-utilities-advisory-committee)

COUNCIL STAFF REPORT

CITY COUNCIL *of* SALT LAKE CITY

TO: City Council Members

FROM: Nick Tarbet
Policy Analyst

DATE: May 7, 2019

Item Schedule:
Briefing: May 7, 2019
Set Date: May 7, 2019
Public Hearing: June 4, 2019
Potential Action: June 11, 2019

RE: **Text Amendment: Permit Self-Storage in the D-1 Zoning District**
PLNPCM2018-00645

ISSUE AT-A-GLANCE

The Council will be briefed about an ordinance that would allow self-storage facilities in the D-1 Central Business District. They would be limited to basement or below ground levels only and not allowed on the ground or upper levels of the building. The text amendment is the result of a private petition. The applicant is making this request so they can repurpose parts of a building they are remodeling.

The Planning Commission forwarded a positive recommendation to the City Council.

Goal of the briefing: *To review the proposed text amendment, determine if the Council supports moving forward potentially direct staff to prepare for a public hearing.*

ADDITIONAL INFORMATION

Pages 3-5 of the Planning Commission staff report identify four key issues. A short description of each issue and the finding is provided below for reference. Please see the Planning Commission staff report for full analysis.

1. **Appropriateness of Storage in a Highly Dense Area**
    - There have been several multistory storage developments built in the periphery of downtown.
    - Self-storage downtown may provide support for uses that promote commercial and economic development as long as the storage itself is done in a non-impactful manner (does not detract from the activity).