TURN
THE UTILITY REFORM NETWORK

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PREPARED TESTIMONY OF MARCEL HAWIGER

POLICY TESTIMONY REGARDING AFFORDABILITY AND GRID MODERNIZATION INVESTMENTS

Submitted on Behalf of

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LIST OF TABLES

LIST OF FIGURES

HAWIGER POLICY TESTIMONY REGARDING AFFORDABILITY AND GRID MODERNIZATION INVESTMENTS

SECTION 1: AFFORDABILITY

1 Introduction

My name is Marcel Hawiger. I have been a staff attorney with the Utility Reform Network ("TURN") since 1998, and have worked on numerous proceedings related to revenue requirements, rate design, electric and gas procurement and demand side management issues. My qualifications are included in Attachment 1.

In the following testimony I address two policy issues. First, I address affordability of electric service for SCE customers. I provide data demonstrating that the bills for over one million SCE non-CARE residential customers in hot areas are significantly higher than the national average. Disconnection rates for SCE customers have doubled over the past five years. I discuss the fact that distribution capital spending is the primary cause of SCE's high rates. I conclude by recommending that the Commission explicitly consider the painful impact of high SCE electric bills when it reviews spending requests that may not be absolutely necessary for the provision of safe and reliable electric service. The Commission must hold SCE responsible for properly evaluating the benefits and costs of spending proposals, as the Commission requested at least two rate cases ago.

Second, I address policies related to SCE's proposal to spend over two billion dollars to modernize about 20% of its circuits. I provide a lay explanation of the problems SCE claims to address, and explain that SCE has failed to show that there have been any operational challenges in interconnecting rooftop net energy metered solar systems. I address the operational and ratemaking differences between retail and wholesale solar systems to demonstrate that the

Commission must be very cautious in interpreting SCE's testimonies concerning grid modernization.

2 Affordability is a Problem for SCE's Residential Customers

2.1 SCE's Customers in Hot Areas Pay Bills That Are Significantly Higher than the National Average

SCE's residential rate in 2015 was the seventh highest among the top 50 investor owned utilities.

Historically, the utilities have downplayed high electric rates in California by noting that bills were only average, due to the very low electric consumption in the state. In its last rate case, SCE presented data showing that average monthly residential electric consumption in its service territory in 2012 was 60% of the national average (based on the 50 largest IOUs), while its average monthly residential bill was 78% of the national average.[1] SCE touted the fact that bills were lower than average as indicative of a lack of any affordability problem.

It is correct that SCE's "average" monthly bills are lower than the national average. However, the average monthly bill statistic hides a critical fact – there are a very large number of customers in SCE's service territory who pay much larger bills than the national average. SCE has over 4.3 million residential customers, making it the second largest IOU in the country, behind only PG&E. In contrast, the average customer size of the top 50 utilities is 1.17 million.

SCE's large service territory includes at least two distinct climate zones – the relatively mild coastal area and the hot inland area. SCE classifies its baseline territories into three climate zones – hot, moderate and cool. SCE has about 1,466,000 customers in hot climate areas

[1] A.13-11-03, SCE-01, p. 14-16. The average consumption was 590 kWh, while the average monthly bill was $94.

(baseline zones 10, 13, 14 and 15), and a total of about 2,873,257 in cool and moderate climate areas:

Table 1: SCE Residential Customer Count for Different Climate Zones

	Hot (Zones 10, 13, 14 and 15)	Moderate+Cool	Total
CARE	520,065	727,840	1,247,905
Non-CARE	945,936	2,145,417	3,091,353
SCE Total	1,466,001	2,873,257	4,339,258

If SCE's service territory were separated into two separate utilities, the "moderate and cool" area would rank third in the nation by customer count, and the hot area would rank twelfth in the nation, out of about 190 investor-owned utilities. Indeed, just the non-CARE portion in the hot area (945,936 customers) would by itself rank in the top 25 utilities in the country.

Comparing the **average bills** for SCE and PG&E to other utilities in the country masks the size and geographic diversity of California. Inland customers in hot areas consume significantly more electricity on average due to the need for air conditioning. The average bills for those customers in hot versus non-hot climate zones are drastically different, as illustrated in Figure 1 and Figure 2 below.[2]

[2] These difference is true even though coastal customers actually pay higher "average rates" due to the fact that California has tiered rates, and customers in hot areas have higher "baseline quantities" subject to the first and lowest tiered rate. This has always been a confusing issue. The truth is that if a customer in San Francisco used as much electricity as a Fresno customer, they would actually pay a higher monthly bill.

Figure 1. The 1.466 million SCE Customers in Hot Climate Zones Pay 29% More than Customers in Cool Climate Zones

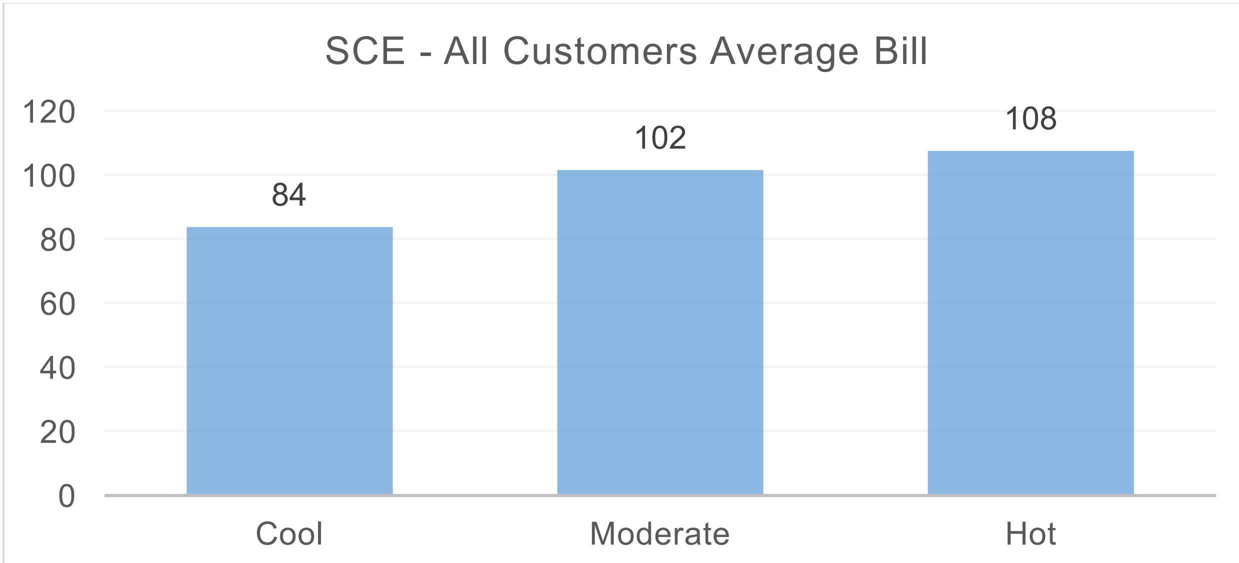
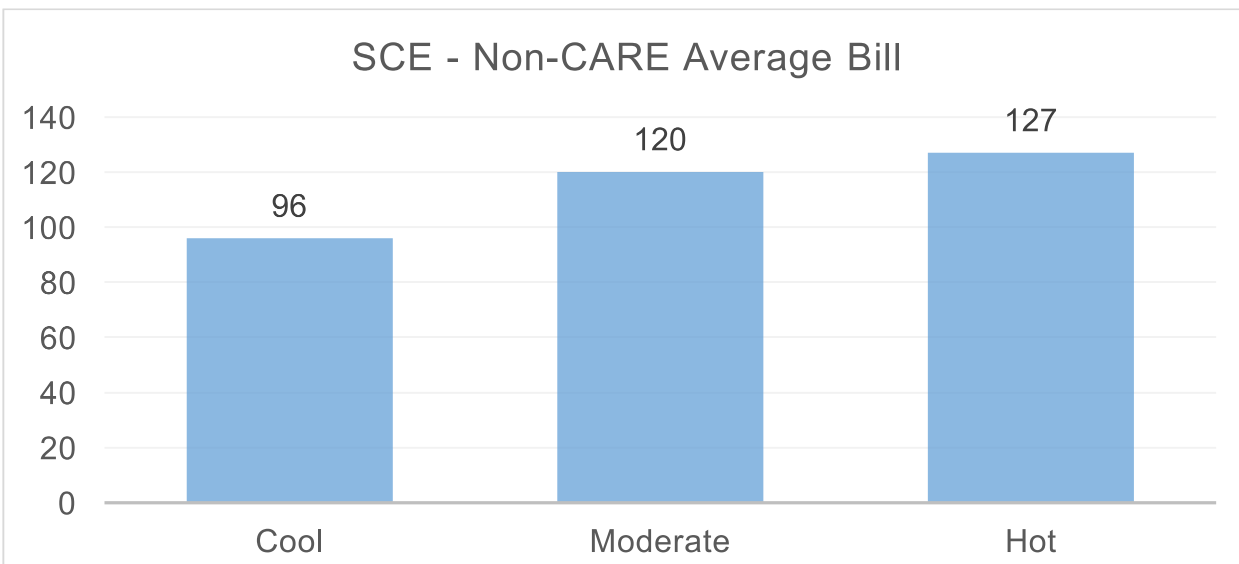
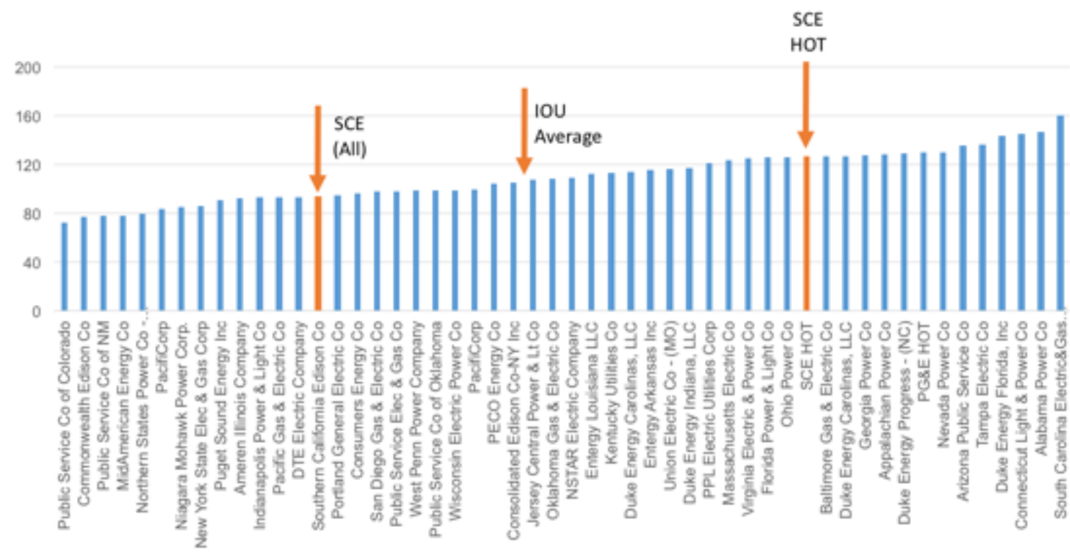


Figure 2. The 0.945 Million non-CARE SCE Customers in Hot Climate Zones Pay 32% More than non-CARE Customers in Cool Climate Zones



When these data are used to compare SCE bills to national figures, the result shows that the average annual bill for the approximately one million non-CARE customers in hot climate areas ranks about 15th in the nation, as illustrated in Figure 3. In other words, the standard adage that bills in California are below the national average is demonstrably untrue for at least one million SCE residents whose bills are much higher than the national average.

Figure 4. SCE Non-CARE Customers in Hot Climate Zones Pay Bills about 20% Higher than the National Average



While I do not attempt to quantify the relative prosperity and cost of living in different California regions, a number of inland counties with hot climates have high rates of poverty. For example, the highest percentage of low-income CARE customers is present in the Central Valley.[3] Moreover, high cost of living and years of budget cuts for social programs in California have resulted in some of the highest poverty levels in the country.[4] Thus, high electric bills have a very significant impact on household finances and affordability of electric service.

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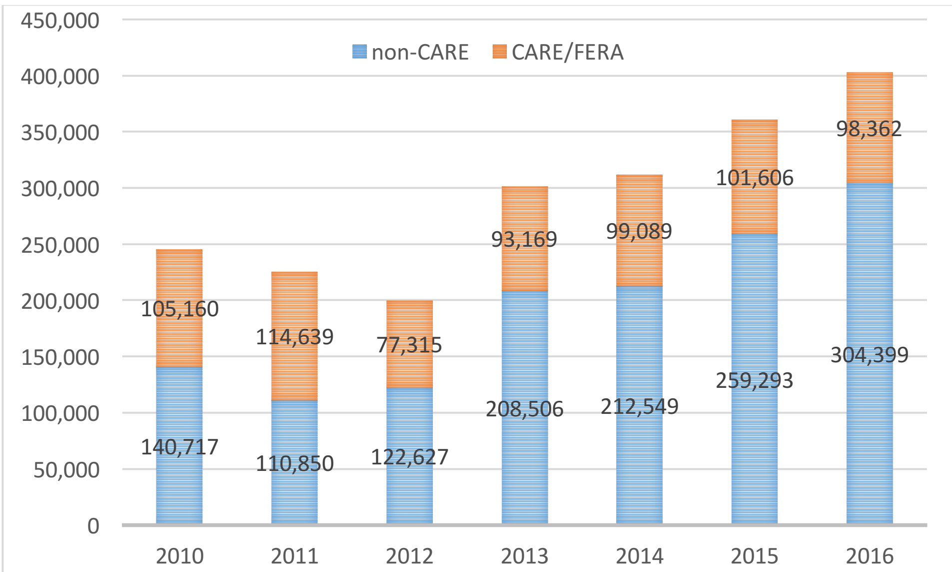
[3] CPUC, PPD, "Geospatial Analysis of California's Utility Services," May 23, 2016, p. 19.
[4] Stanford Center on Poverty and Inequality, "The California Poverty Measure," 2013.

2.2 Disconnections Have Increased Significantly Over the Past Five Years

One reflection of the high bills and lack of affordability for many SCE customers is the high level of utility disconnections of service for non-payment. After declining somewhat in 2011 and 2012, presumably due to improved economic conditions, disconnections have dramatically increased, so that by 2016 the total number of annual disconnections was double the number in 2012.

Figure 5: SCE Annual Number of Disconnections Increased by 100% from 2012 to 2016



3 Distribution Capital Spending by SCE Is the Cause of High Rates

3.1 Distribution Rates Are the Cause of SCE's Rate Increase Over the Past Decade

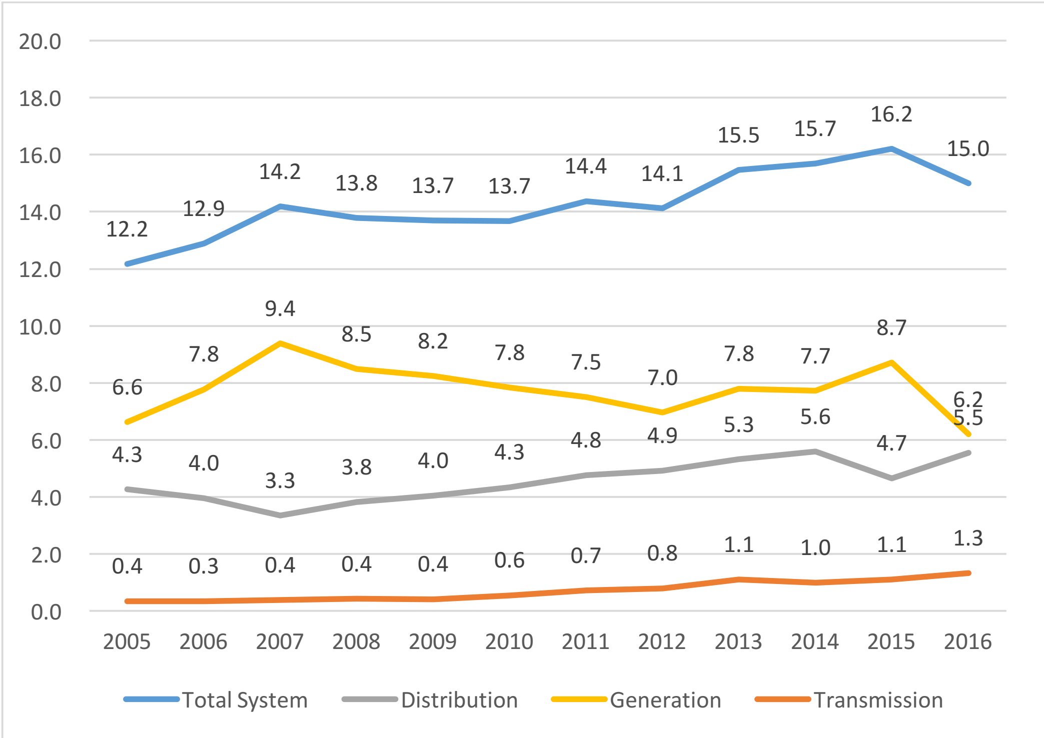
SCE's total bundled rate increased from below 13 cents in 2005-2006 to above 15 cents in 2013-2016. At the same time the total bundled residential rate increased from 12.4 to 17.1 cents/kWh from 2005 to 2015. The 38% increase in the average residential rate was higher than the CPI increase of about 23% during the same time period.

There is misperception concerning the causes of high utility rates in California in general, and for SCE in particular. For example, a *Los Angeles Times* story from February 5, 2017, blamed high rates on construction of excess generation capacity. Similarly, others have blamed high rates on renewable power construction.

The data do not support these hypotheses, but instead indicate that it is spending on the distribution system that is driving up rates. SCE's generation rates declined significantly between 2007 and 2016, and the increase in average system rates has been driven almost entirely by increases in distribution rates, as illustrated below. Since 2006, the total bundled rate has increased 16%; the distribution component has increased 40%; while the generation component has decreased 20%.

The generation component of SCE's rate has declined as a proportion of the total average bundled rate. From 2010 and 2016 the generation portion decreased from 57% to 41% of the total rate, while the distribution portion grew from 32% to 37% of the total rate, as illustrated in Figure 6.

Figure 6: SCE System Total Bundled Rate (2005-2016)



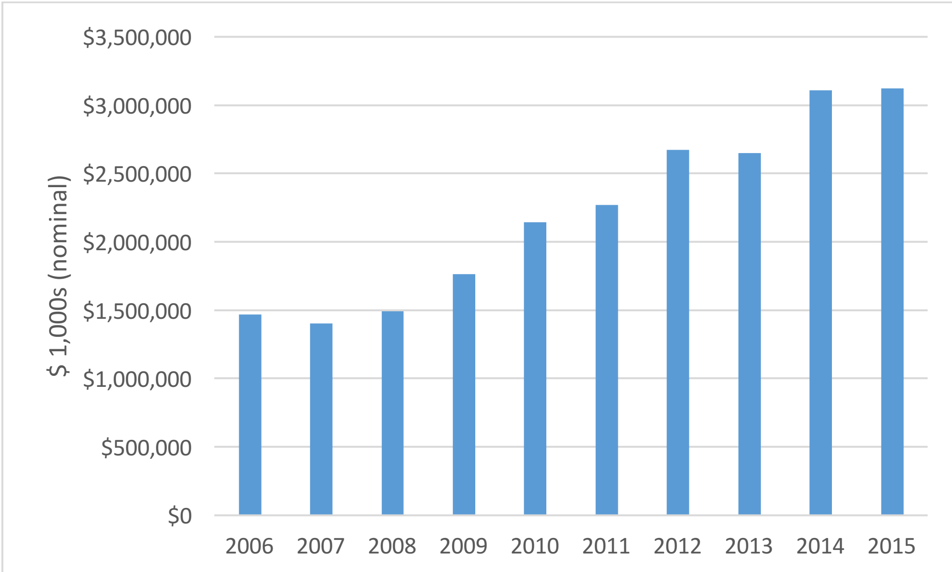
The generation component includes both the costs of generation capacity, as well as fuel and purchased power. The latter costs have been abnormally low due to 1) a decline in total sales from over 78,000 GWh per year in 2007-2009 to under 74,000 in 2013-2015; and 2) very low and stable natural gas prices since about 2010. The steady increase in distribution rates has been masked by the relatively low generation rates.

3.2 Distribution Rates Are Just Beginning to Reflect High Capital Spending

These distribution rate increases are only beginning to reflect the huge increase in annual transmission and distribution capital spending over the past decade. SCE's total Transmission and Distribution (T&D) annual capital expenditures **doubled** between 2006 and 2015 (an increase of 100%), as compared to a total inflation increase of less than 20%.[5]

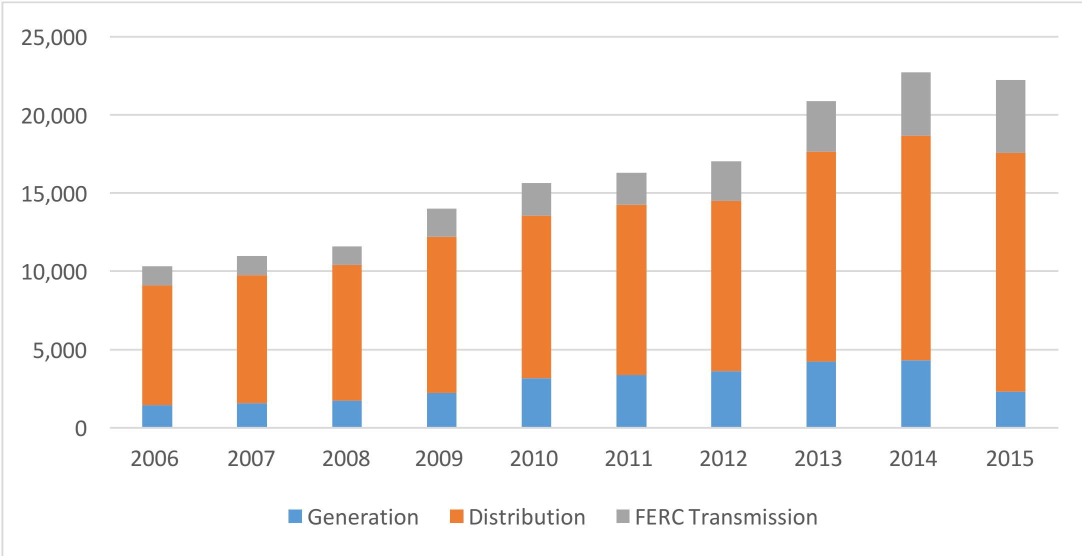
[5] CPI increased from 198.3 in 2006 to 236.5 in 2016, an increase of 19.3%.

Figure 7: SCE T&D Business Unit Capital Expenditures Grow 100% from 2006 to 2015



The contribution of T&D capital spending is most evident when one looks at SCE's rate base growth since 2006, as illustrated in Figure 8. SCE's rate base more than doubled from $10.304 billion in 2006 to $22.231 billion in 2015. The T&D component rose from $8.856 billion to $19.943 billion, while the generation component rose from $1.448 billion to $2.288 billion. In other words, the generation component of rate base fell from about 14% to about 10% of total rate base from 2006 to 2015.

Figure 8: SCE's Rate Base Has More than Doubled Since 2006[6]



TURN recognizes that there are some legitimate reasons for increased capital spending, such as SCE having embarked on a course of "replacing aging infrastructure." Also, some of the spending in Figure 7 above includes transmission spending to interconnect renewable resources. Nevertheless, the level of SCE's capital spending is extremely troubling from an affordability perspective. TURN's analyses in this and prior rate cases indicates that some of the capital spending is unnecessary. Once SCE's capital spending is included in rate base and grossed up for utility profit and taxes, it will contribute to revenue requirement and rate increases for decades to come.

An escalation of distribution rates may also negatively impact the growth of community choice aggregation, given that the narrowing of the gap between distribution and total rates reduces the margin that can be avoided by CCA customers.

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[6] Source: CPUC Website: Electric Costs/Rate Base. See: http://www.cpuc.ca.gov/General.aspx?id=12092

3.3 SCE’s Distribution Spending Is High Compared to Other Large Utilities

SCE’s distribution spending over the past few years is out of line with spending by other large utilities. As illustrated in the figures below, the growth in SCE's distribution assets per customer in 2010-2015 has out-paced the average US IOU by 50%, with SCE’s assets growing 36.9% compared to a utility average of 23.2%. The result is that of the 34 US IOUs with more than 1 million customers, not a single one has grown distribution assets per customer more than SCE from 2010 to 2015.

Figure 9: SCE Leads the Nation in Growth of Distribution Assets[7]

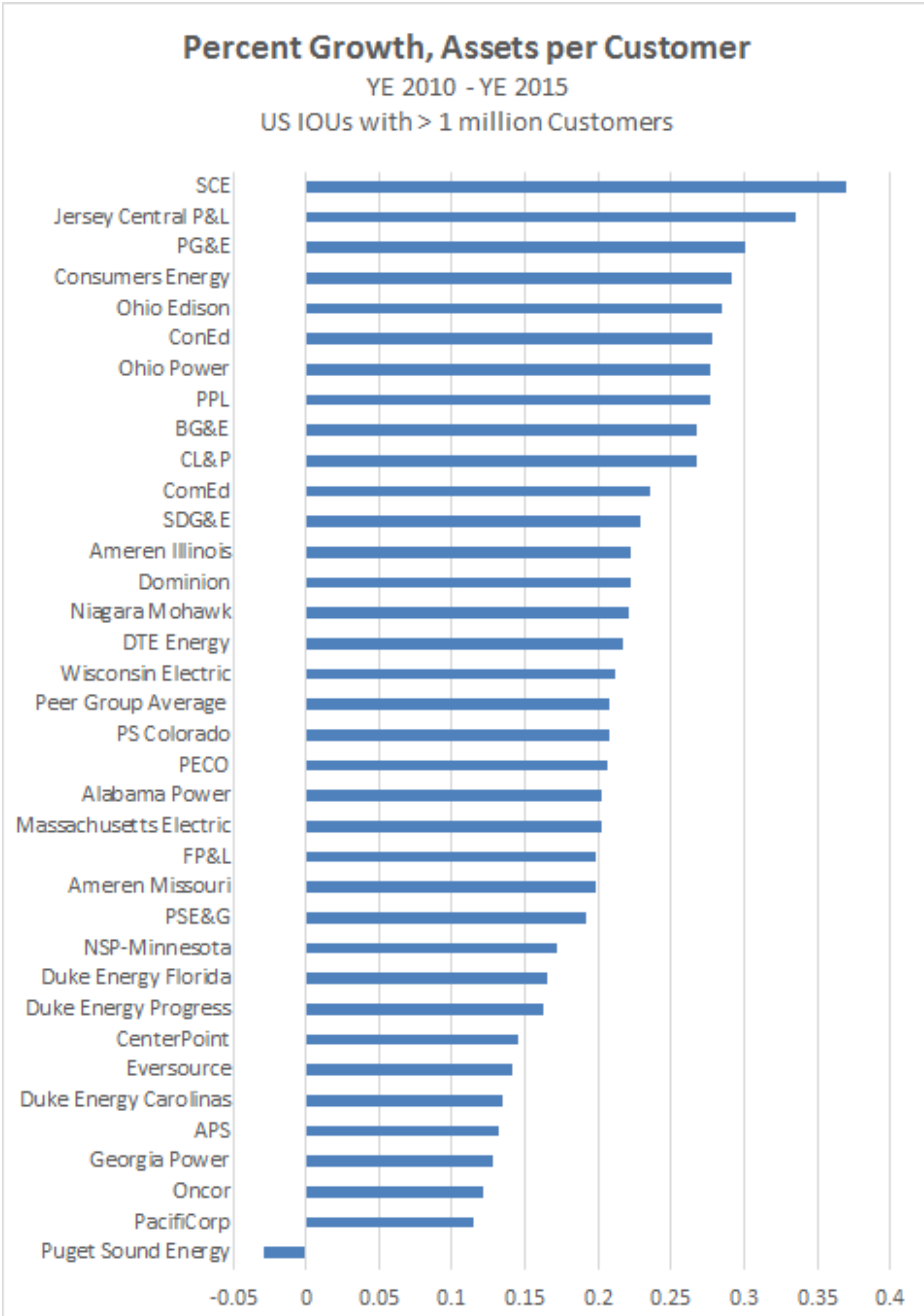
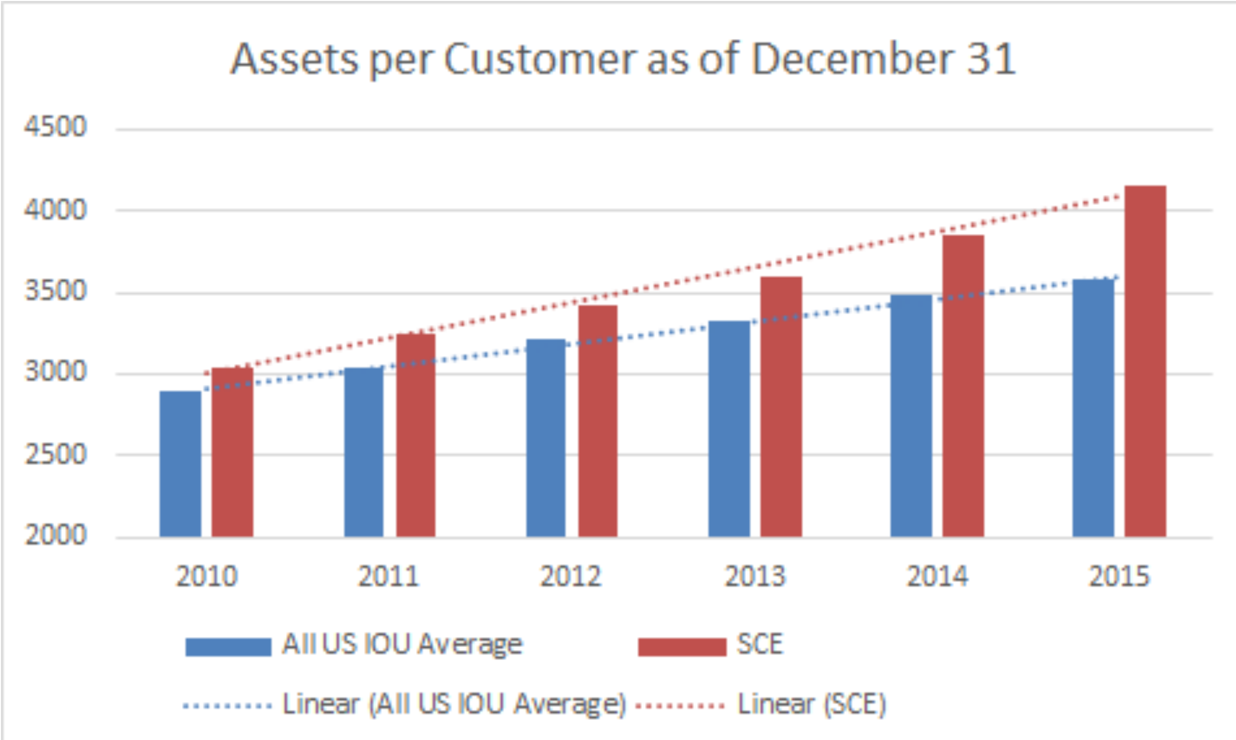


Figure 10: SCE's Assets per Customer Are Significantly Higher than the National Average



Benchmarking utility performance is a tricky business, as every utility may have unique circumstances and cost drivers. However, a perusal of the trade press shows that many utilities around the country have needs for infrastructure replacement and asset deployment. The Commission should require SCE to explain why its growth in distribution capital spending and distribution assets has diverged so greatly from the national norm.

4 The Commission Must Hold SCE Accountable for Demonstrating the Need and Cost Effectiveness of Proposed Spending in This Rate Case in Order to Minimize Harm to Ratepayers and Promote Affordability of Electric Service

The Commission is tasked with evaluating the reasonableness of all utility spending requests in this rate case. This is a complex undertaking. How should the Commission

[7] Gross Distribution Plant data per customer, for Figure 9 and Figure 10, secured from the *Utility Evaluator,* a product of the Wired Group. Accessed March 8, 2017 via the Internet at http://www.utilityevaluator.com.

incorporate the data concerning high electric bills, high utility disconnections and extraordinary spending increases in its decision-making?

First, consistent with the foregoing analysis, the Commission should explicitly find that average bills for the large number of SCE's customers in hot climate areas are significantly higher than the national average electric bill, and that such high bills contribute to the lack of affordability of utility service for many Californians. Utility disconnections have increased significantly for both CARE and non-CARE customers. The Commission should also find that while CARE is a very useful program, it does not solve all affordability problems.

Second, the Commission should consider this information when weighing approval of certain spending requests. Undoubtedly there are many requests in this rate case that represent spending necessary to provide safe and reliable service. However, there are also a multitude of programs and program elements that provide some value, but are not necessary for safe and reliable service. For example, improving certain utility real estate assets may be worthwhile for employee satisfaction, but it may not be necessary for safety or reliability. Reconductoring more circuits may help improve reliability incrementally, but the added reliability value may not be worth the additional rate increase.

There are various examples of programs that are certainly desirable, but should not be given high priority. For example, SCE proposes to continue its elimination of 4 kV circuits. However, as shown in the testimony of TURN witness Stephens, this replacement program is not worth the reliability benefits, based on SCE's own value of service analysis. Other TURN witnesses provide recommendations for deferring or eliminating programs based on relative need to accomplish valid goals.

The Commission can, and does, address issues related to affordability in other proceedings, especially those focused on rate design, low income energy efficiency, and the design of the CARE discount program. However, those cases address how to deal with the back-end - how to ameliorate the impact of high rates and bills through other programs and cost allocation. They do not address the underlying cause of the high bills. The primary drivers of high customer bills, even with relatively low consumption levels compared to other states, are the high revenue requirements and associated high electric rates. It is in this rate case, as well as other discrete applications for spending authorization, that the Commission can actually mitigate the root of the problem by weeding out spending requests that that provide minimal benefit from a safety and reliability perspective or rank lower than other investments in terms of their cost-effectiveness in improving safety and reliability or providing other benefits.

In the S-MAP proceedings, the Commission is working hard on developing a methodology to facilitate a quantitative comparison and ranking of utility programs and projects based on their cost effectiveness in promoting safety and reliability and other benefits. While those efforts are still ongoing, the Commission has made clear that, even without an adopted S-MAP methodology, utilities must show how they prioritize their spending requests in order to assist the Commission in its effort to strike the right balance between safety and reliability and affordability. In the 2014 Pacific Gas and Electric (PG&E) GRC decision, the Commission stated that "[i]t is not enough to merely assert that safety would be compromised absent approval of a particular work effort" because "[v]irtually everything a utility does [has] some nexus to safety and can be deemed to have some safety impact …."[8] Instead, "the emphasis should be on

[8] D.14-08-032, p. 28

those initiatives that deliver the optimal safety improvement in relation to the ratepayer dollars spent."[9]

Regrettably, SCE did not perform this type of prioritization on its own. When asked by TURN how SCE selected which programs and projects to include in its request and how it prioritized or ranked projects, SCE explained that:

> SCE's forecasts for the projects, programs and activities presented in this GRC are developed based on customer, grid, and operational needs," reviewed by management "for scope, cost, schedule, resource needs/allocation, execution feasibility, and benefits (such as safety, reliability, compliance, operational efficiency, avoided costs, etc.). The final proposed revenue requirement (calculated after the capital expenditure, O&M expense and other operating revenues are accounted for) is then assessed against the corresponding rate impact on customers.
>
> SCE did not develop its GRC forecasts based on spending or revenue requirement "targets." The GRC forecast takes into consideration assessing the customer, grid and operational needs and determining effective, efficient, and cost effective ways of meeting those needs balancing benefits and costs.[10]

SCE's response describes no actual prioritization, and only vaguely references consideration of costs and benefits and cost effectiveness. Later in the response, SCE gives two examples of spending requests for which SCE conducted a cost-benefit analysis:

> In certain cases throughout this process, SCE performed cost-benefit analyses to help evaluate the cost effectiveness of capital projects. Two examples include: (1) in SCE-02, Volume 8 – Infrastructure Replacement, SCE conducted cost-benefit analysis of performing testing of mainline cable in the WCR program, and (2) in SCE-04, Volume 2 – Capitalized Software, SCE conducted a cost-benefit analysis on the Centralized Remedial Action Scheme project.[11]

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[9] *Id.*
[10] DR-TURN-110-01. Dated 4/4/2017.
[11] *Id.*

Unfortunately, both of the examples SCE provides – the mainline cable replacement and the CRAS – are cases where in prior GRCs TURN successfully challenged SCE's requests precisely because the Company made no efforts to provide a cost-benefit analysis or evaluate more cost-effective alternatives. For the cable replacement program, the Commission agreed with TURN in the last GRC that SCE failed to properly account for the potential benefits of a cable testing program.[12]

With respect the CRAS program, the Commission concluded in the last rate case:

> TURN's argument that the benefits of CRAS are not quantified is compelling; indeed, we would like to see more concrete cost-benefit analysis than SCE has provided here. However, the intuitive appeal of the CRAS benefits that SCE describe are strong and the outcome of any effort to quantify them at this time may be primarily driven by preliminary assumptions (number of interconnections, policies on economic curtailment, etc.). ...
>
> SCE's recorded capital expenditures for 2013 are approved; capital expenditures for later years and O&M are denied. **SCE may reapply for the denied capital expenditures in its next GRC, if it provides a detailed cost-benefit analysis in support of that request**.[13]

It is a step in the right direction that in this case SCE finally conducted a cost-benefit analysis for two programs where the Commission directed SCE to provide more specific analyses of benefits and costs, and after TURN had criticized SCE (in at least one if not two rate cases in a row) about its inadequate analyses.

However, SCE should have done better. Even without an adopted S-MAP methodology, SCE should have performed its own benefit-cost analyses and cost-effectiveness evaluations of alternatives at least for its major programs, without waiting for other parties to raise these issues.

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[12] D.15-11-021, p. 72 ("We agree with TURN that SCE's request to dramatically increase the pace of cable replacement shortly before the benefits of this testing program are fully understood or realized is questionable.")

[13] D.15-11-021, p. 43-44 (emphasis added).

Indeed, the Commission has sought precisely this type of showing from SCE. In the 2012 GRC, the Commission directly addressed SCE's contention that many activities are "not suited to cost-benefit analysis":

> The burden is on SCE to not only establish that the proposed work activities are necessary, but also that SCE has prudently examined alternatives before coming to ratepayers to fund the chosen action. The Commission reviews SCE's showing to ensure that SCE is addressing the work in a cost-effective manner. For some items, we were persuaded that SCE did not provide the necessary support for requested funding and we made reductions. In other areas, where there is a new program or technology, we recognize that reasonableness may be otherwise demonstrated.[14]

Just two years later, when addressing safety-related spending for PG&E, the Commission reiterated this very same point even more strongly:

> In evaluating PG&E's cost claims, we require that unless a work activity or program is mandated, the utility must demonstrate that the overall benefits justify the costs imposed on ratepayers. Although quantitative benefits may not necessarily exceed the costs, such benefits should be quantified as much as possible.[15]
>
> ...
>
> PG&E should demonstrate that it compared the cost of alternative approaches to performing the work activity and that the proposed approach is the most cost-effective. The burden is on PG&E to establish that its proposed work activities are necessary, and that it has prudently examined alternatives before receiving ratepayer funding.[16]

TURN urges the Commission to hold SCE to these standards that the Commission clearly articulated in two recent rate cases. We recommend that the Commission keep the shortcomings in SCE's showing in mind as it reviews the substantive analyses of TURN witnesses who show

[14] D.12-11-051, p. 16.
[15] D.14-08-032, p. 27.
[16] D.14-08-032, p. 28-29.

that some of the large programs either do not provide net benefits, or are not the most cost-effective method of achieving a particular goal.[17] The Commission should only approve the minimum spending truly necessary to provide safe and reliable service, and spending proposals ostensibly meant to improve "safety or reliability" must be scrutinized to ensure they provide meaningful benefits in relation to the requested spending, and to ensure that SCE is not ignoring less expensive methods that would work as well to achieve valid goals.

[17] As just two example in TURN's testimony, see TURN's analysis of the 4 kV elimination program and the grid modernization program in the accompanying exhibits TURN-04 (Jones) and TURN-06 (Alvarez and Stephens).

SECTION 2: GRID MODERNIZATION

5 Introduction to Grid Modernization Policy Testimony

5.1 Purpose of My Testimony Regarding Grid Modernization

A lot of ink has been spilled concerning the issue of "grid modernization" investments proposed by SCE in this case. The Commission hosted two workshops in this proceeding in which SCE described in detail their grid modernization plan.

My impression from the workshops and testimonies is that there is some lack of clarity concerning the relationship between SCE's proposed grid modernization investments and the adoption of various distributed energy resources ("DERs") that are a component of the state's clean energy goals. The goal of this policy testimony is to explain and clarify, in language accessible to the lay reader,[18] the following:

- a description of how grid modernization investments are meant to promote reliability and DER adoption, not to improve "safety" of the electrical system;
- the nature of the "masked load" problem facing distribution operators during routine switching, and how this problem relates to the presence of either behind-the-meter or in-front-of the meter solar photovoltaic distributed generation ("DG") systems;[19]
- the fact that SCE has not encountered any problems with interconnecting behind-the-meter NEM solar systems, as total upgrade costs due to such systems have been less

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[18] Many of these issues are covered in more technical language in the TURN testimony of Paul Alvarez and Dennis Stephens.

[19] Solar distributed generation systems can be either retail or wholesale. Wholesale systems are "in-front-of the meter," do not serve any on-site load, and sell energy under a purchased power agreement. Wholesale system are larger than 1 MW and are governed by Rule 21 or WDAT interconnection. Retail systems are "behind-the meter," and almost always operate under a net energy metering (NEM) tariff. The NEM limit is 1 MW, though some systems may have a larger nameplate capacity. I use the terms "retail" and "NEM" interchangeably. I also use the term "rooftop" for retail projects, although wholesale PV projects could be located on the ground or on support structures, such as car shading structures.

than $15 million from 2013-2016, and SCE can point to no examples of any operational problems due to NEM systems;[20]

- the fact that the few problems that SCE has encountered with masked load are almost all due to the presence of larger wholesale DG systems on certain circuits;
- the fact that the cost to automate the 74 capital project deferral pilot circuits is twice the cost of the projects which might be deferred.

Please note that while I provide a high level description of SCE's switching operations as necessary background for my policy testimony, the technical details concerning utility switching operations, both with respect to DERs and reliability, are addressed in the testimonies of TURN witnesses Alvarez and Stephens (TURN-06) and Jones (TURN-04).

5.2 DER Is a Euphemism for Distributed Generation, at Least as Far as SCE's Grid Modernization Is Concerned

While SCE's testimonies refer generically to distributed energy resources ("DER"), it is important to note that the actual problems related to grid operations that are addressed in SCE's testimony – reverse power flow and masked load - relate to the impacts of distributed solar generation ("DG") on the flow of electricity. I will thus refer to "DG" throughout my testimony when discussing grid modernization. This is not to say that other forms of DER are not important for grid planning. Accurate forecasts of load impacts due to, for example, energy efficiency or electric vehicles, may be an issue for grid planning and certain investments. However, these other DERs are simply not a significant factor in the problems that SCE is trying to address relative to distributed generation in general, and PV Solar in particular.

[20] The data supporting this section are unique to my testimony and not covered by Alvarez and Stephens.

6 The Primary Purpose of Grid Modernization Investments is to Promote Reliability and DER Integration, Not to Address Safety Risk

From various discussions at the DER workshops, it appears to me that there is some confusion about the relationship of SCE's proposed grid modernization investments and the safety of electric service. This confusion is quite understandable, given that the very beginning of SCE's testimony claims that grid modernization will "enhance safety and reliability."[21]

First, it is important to remember that two-thirds of the grid modernization work is intended purely to improve reliability by reducing the number of customers impacted by a fault condition (through sectionalizing via more switches) and by reducing outage response times (through telemetry, the GMS and automation). These are the 200 "WCR" circuits targeted each year for the various investments associated with grid modernization. These investments should be evaluated using standard benefit-cost or cost effectiveness analyses. The TURN testimony of Garrick Jones provides exactly such analyses, and shows that the vast majority of benefits can be obtained by a much smaller investment, primarily by using remote-controlled switches without all the automation.

The other one-third of the grid modernization work is the "DER-related" work targeting about 88 circuits per year. However, while the justification for these circuits differs, the actual planned work is almost **exactly** the same – sectionalizing circuits with automated switches and improving faster response times with the GMS and a new communications network. In other words, these are classic reliability investments in the sense that they function to reduce SAIDI and SAIFI, with an additional intent of addressing the masked load problem, as discussed further below.

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[21] SCE02v10, p. 5.

Safety and reliability are certainly related, and any outage has health and safety implications due to the very fact that there is no electric service. While mostly an inconvenience, lack of electric service can have serious health and safety impacts on people who rely on certain medical devices or on air conditioning during a heat wave. Nevertheless, these health and safety impacts are different in kind from the types of electric system problems that directly result in accident, injury or death due to, for example, contact with live downed wires or a wildfire caused by tree contact with live wire.

The distribution automation asset investments and other components of grid modernization are not designed to prevent failures of the type that create hazardous conditions. Rather, grid modernization is intended to reduce outage times by facilitating faster response and reducing the number of customers impacted by an outage.[22] I thus agree with Mr. Roberts of the ORA that grid modernization should be evaluated based on its reliability benefits and its ability to support DER growth.[23]

7 Grid Modernization as Proposed by SCE Is Not Necessary to Promote DER Growth

The testimony of TURN witnesses Alvarez and Stephens explain in detail why SCE's full automation solution is not the cost-effective answer to promoting DER growth. In this testimony I provide I more high level and lay explanation of the operational problems SCE is attempting to solve, and then discuss how these problems relate to the presence of either retail NEM systems or wholesale DG systems. The purpose is to alert the Commission to the fact that SCE may be substituting ratepayer funding for grid modernization, which is expensive and increases SCE's rate base and profits, for required upgrades by wholesale DG developers to address potential

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[23] ORA-9, p. 44-45.

problems. I then provide an example of how SCE's targeting of 74 circuits due to its Distribution Project Deferral Pilot makes absolutely no economic sense, as it costs more than twice the value of the projects which might be deferred.

7.1 The Primary Operational Challenge of "Masked Load" Can Be Solved by Less Expensive Means of Obtaining Distributed Generation Production Data

In the Distribution Resource Plan proceeding the Commission has embarked on a process to develop methodologies for assessing the hosting or "integration" capacity of circuits (the integration capacity analysis or "ICA") and to determine the locational benefits provided by a distributed energy resource (the locational net benefits analysis or "LNBA"). The ORA testimony of Tom Roberts presents a detailed account of the DRP and how it relates to the grid modernization proposals in this proceeding.[24]

The more than two billion dollars in "grid modernization" work to sectionalize and automate almost 900 circuits (2018-2020) is not intended primarily to increase the hosting capacity of the circuits. First, two-thirds of the work is purely and completely intended to improve system reliability by expanding the scope and nature of the traditional Worst Circuit Rehabilitation program so as to reduce the number of customers impacted by a fault condition and reducing outage response times, as discussed in the preceding section. Second, the portion of the investments ostensibly to promote DER is intended to address operational issues caused by a changing power flow and by "masked load" during switching operations. The actual distribution automation assets that would be installed on "DER" circuits versus "WCR" circuits are almost exactly the same.[25]

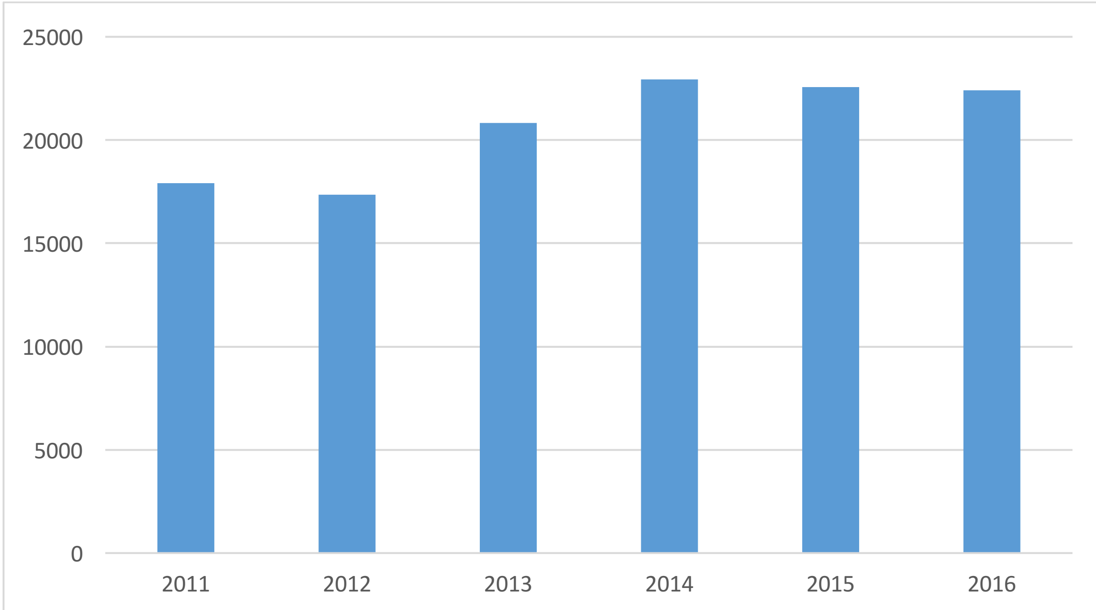
[24] ORA-09, Roberts, p. 14-40.
[25] Mr. Roberts for ORA provides a very good summary of the nature of the distribution automation assets intended for both WCR and DER circuits. ORA-9, p. 94-100.

SCE's Volume 10 testimony explains that the primary operational challenge troubling SCE is the masked load problem. The masked load problem was identified and described in the distributed resource plan submitted by SCE in R.14-10-003.[26] It is described most explicitly in Volume 10 at pages 37 and 46-47 and in Appendix A.

In brief, the masked load problem reflects the fact that distribution circuits are networked, such that one circuit is generally connected to one or more other circuits via a "tie switch." Most of SCE's circuits also have at least one "mid-point switch" which allows the circuit to be divided ("sectionalized") into subparts. The tie switch is normally "open," meaning that no electricity flows between the circuits. However, whenever a utility performs planned maintenance, it generally de-energizes the portion of the circuit on which maintenance activities occur. In order to minimize the impact on customers, one of the first steps the utility does is to transfer a portion of the load from one circuit onto an adjoining circuit by performing a "switching" operation, meaning opening a mid-point switch and closing a tie switch to transfer the portion of the circuit that does not need to be de-energized to a different circuit. This type of planned switching is sometimes termed "grid reconfiguration." SCE performs about 20,000 planned switching operations per year, as illustrated in Figure 11. Emergency switching is also used to reduce the impact of an outage on customers, serving as many customers as possible from a back-up circuit when the circuit from which they normally are served is down due to some unplanned event, from lightning strikes or wildfires to auto accidents and animal contact.

[26] R.14-08-013, SCE Distributed Resources Plan, July 1, 2015, p. 194.

Figure 11: SCE Planned Switching, 2011-2016[27]



SCE explains that when it performs planned switching, its distribution operations engineer needs to know how much load will be transferred from the "switched" portion of the circuit to the adjacent circuit in order to prevent potential overload or voltage problems. However, the engineer only knows the actual load and voltage at the substation. If there is significant distributed generation anywhere on the circuit, it causes the total load at the substation to be lower. The engineer can perform calculations to estimate the load on the portion of the circuit being transferred based on approximating the number and composition of customers on the circuit and the location and output of DERs, a process known as "grid state estimation."[28] Depending on the location and actual output of any DG systems, the load that would be transferred could be more than the estimated load. SCE claims that this could cause

[27] SCE Response to TURN-052-13.
[28] Grid state estimation is discussed in more technical detail in the testimony of Mr. Stephens.

problems during switching, as described in examples 2 through 6 of the Appendix A to volume 10.

There are two high level observations I would like to make concerning the masked load problem.

First, even though all of SCE's examples in Appendix A use figures that are would be associated with a retail NEM system, SCE can point to no examples of problems actually occurring due to rooftop NEM solar systems. SCE's examples of actual problems reflect discrete situations which were apparently caused by large wholesale solar systems or a very large aggregation of rooftop solar designed for virtual net metering, as discussed in Section 7.3 of this testimony. The distinction between wholesale and retail systems is not just an academic question. The rules concerning telemetry and payment for necessary upgrades are totally different for these two types of solar generation systems, and thus the potential solutions could be very different. The fact that actual problems have been caused by wholesale systems is somewhat confusing, since in its Distribution Resource Plan SCE explained that it has "real-time visibility into DG installations ... greater than 1 MW" due to telemetry requirements, so that the masked load problem is generally caused by many small systems.[29]

Second, as SCE's examples in the Appendix make very clear, the primary cause of the masked load problem is the lack of accurate information concerning the output of DG systems. For example, SCE's Example 4 explains that: "The operator has access to a database showing that there are 300 amps of potential DER generation connected to Section y, but he does not know how much is actually being produced in real-time." The key issue is thus obtaining more accurate data or estimation of DG output, not necessarily sectionalizing the circuit or automating

[29] R.14-08-013, SCE DRP, July 1, 2015, p. 194.

switching, and SCE agrees that the problems could be fixed with access to this information.[30] The testimony of Mr. Alvarez and Mr. Stephens explains in detail how obtaining generator output data can be done much less expensively without spending over one million dollars per circuit[31] for the full automation solution proposed by SCE.

7.2 There Does Not Appear to be a Problem with Integration of Behind-the-Meter (Retail or NEM) projects

The Commission may be understandably worried whether the tremendous success of the rooftop solar industry might be harmed if SCE has problems interconnecting new rooftop solar projects. As described by TURN witness Stephens, there are no examples of any significant operational problems due to the interconnection of rooftop behind-the-meter solar projects.

Indeed, the data illustrate that SCE has been successfully able to interconnect rooftop solar systems expeditiously without significant spending, despite the huge increase in installed net energy metered solar systems over the past three years. Over the time period November 2013 through July 2016, when SCE experienced the rapid growth in NEM systems, SCE spent a grand total of $13.995 million for all interconnection-related costs:

Table 2: SCE Costs to Interconnect NEM systems, Nov. 2013-July 2016[32]

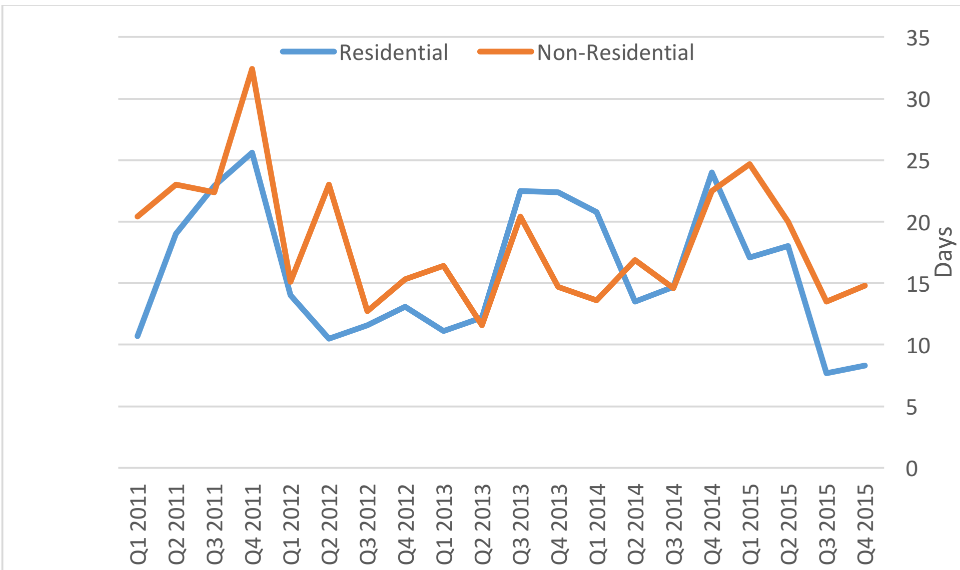
Type of NEM Interconnection Cost	Cost
Dist Engineering (rule 21 studies)	$833,579
Meter Installation	$667,294
Interconnection Facilities	$10,976,544
D Upgrades	$1,517,572
Total	**$13,994,989**

[30] DR TURN-SCE-065, Question 11.a.
[31] This is the figure just for “distribution automation,” not including the significant cost of support investments, such as upgrades to the communication network, equipment control system, and software.
[32] Source: SCE Advice Letters 3239 and 3473.

Type of NEM Interconnection Cost	Cost
NEM Interconnections	153,860
Cost/Interconnection	$91

At the same time, from 2011 through 2015, the time to interconnect NEM systems has remained relatively constant, despite a huge growth in NEM installations:

Figure 12: Average Quarterly NEM Interconnection Times for SCE[33]



The data above illustrate that not only has there been no costly problems with interconnecting the increasing number of rooftop NEM solar systems in SCE's service territory, the interconnection process has actually gotten faster, presumably due to the significant improvements in various processes over the past two years. These data, in conjunction with the testimonies of Mr. Alvarez and Mr. Stephens, demonstrate that there is no evidence of problems associated with the interconnection of retail systems.

[33] Source: Go Solar California, Data Annex (accessed April 18, 2016)

7.3 Problems Apparently Exist Due to the Presence of Large Wholesale DG Systems

SCE does provide a few examples of problems during switching operations caused by solar DG. In its testimony it mentions only one problem – the overload during a load transfer from the Carbon to the Discovery circuit.[34] It turns out that this problem was caused by two wholesale solar systems (with capacities of 5 and 10 megawatts) whose telemetry equipment was "non-functional."[35] Had the telemetry been functional, SCE presumably would have known the real-time output of these systems and thus been able to integrate that information into any switching plans. It was only because the wholesale generators violated SCE's instruction to curtail, and SCE failed to confirm the curtailment, that a problem occurred. Lack of automation was not responsible for the only outage SCE cites in its $2.3 billion proposal.

I have tried to catalogue every problem that SCE has identified in testimonies and several data responses concerning the problem of masked load during switching operations. In each and every case except one, the alleged problem was due to the presence of large wholesale generators on the circuit. The only problem caused by NEM systems was caused by a 700 kW commercial NEM system that was much larger than the on-site load since it qualified under a "virtual net metering" tariff, thus exporting much more power than a typical NEM system.

Table 3: Examples of Masked Load Problems Encountered During Switching Evidence Impacts of Large Wholesale Systems

Circuit with problems experienced due to masked load	**Discovery Reference[36]**	**Testimony ref**	**Circuit Voltage**	**Cause of Masked Load**
Butternut	DR 85-8b	SCE02v10 WP p. 86 Fig 10	12 kV	7 NEM systems on one complex 0.72 MW

[34] SCE02v10, p. 47:12-23.
[35] SCE Response to TURN-09-10.1, 10.3 and 10.4.
[36] All references are to TURN data requests, unless noted otherwise.

Circuit with problems experienced due to masked load	Discovery Reference[36]	Testimony ref	Circuit Voltage	Cause of Masked Load
Carbon	DR 85-9d	SCE02v10 WP p. 86 Fig 11		5 MW Wholesale system
Melody	DR 26-30c, 065-4b, 065-16a, 123-13a		25 kV	Due to 2 MW WDAT
Garnet Substation	DR 26-4a, 65-04, 65-03a			All wholesale
Carbon/Discovery	DR 09-10.1-10.4	SCE02v10, p. 47	12 kV	Due to 5 and 10 MW systems
Resort/Canal	SEIA-005-05.5		33 kV	20 MW WDAT, no NEM
Confidential	DR 63-25a	SCE02v3, p. 17 Fig I-7		29 MW of WDAT wind on one circuit

The problems due to masked load caused by large wholesale generation are somewhat surprising. SCE supposedly requires telemetry for generators above 1 MW.[37] I cannot determine whether the standard telemetry provided for in SCE's Interconnection Handbook was either not required by the Company, or required but not in working order, or required and in working order but not utilized. When TURN asked SCE directly why it could not "control and monitor" a wholesale generator, SCE basically said that the telemetry required pursuant to the interconnection handbook standard was "not adequate."

SCE presently has about 303 MW of wholesale solar generation from 67 projects connected to the distribution system, as shown in the Appendix B. It has an additional approximately 540 MW of non-solar distributed wholesale generation, including several large (>20 MW) wind and gas CHP projects, as well as a number of smaller landfill gas projects.

SCE had over 1,500 MW of distributed NEM systems, which are presumably mostly solar rooftop systems. It might seem surprising that the 300 MW of wholesale solar appears to be quite more problematic than 1,500 MW of rooftop solar. But rooftop solar is located at the load

[37] TURN DR 09-10.4; DR 123-13a. See, also, SCE DRP, p. 194.

and sized to meet load. It is quite possible that some wholesale solar systems are located on rural feeders (where land is cheaper) and where lack of load magnifies power flow problems. This is precisely the issue that Rule 21 interconnection procedures are supposed to address.

In theory, whenever a wholesale system applies for interconnection, the wholesale developer must pay for all distribution upgrade costs necessary to accommodate the system. These upgrades thus do not constitute a capital addition and do not add to utility rate base.

On the other hand, the very limited historical spending for upgrades due to NEM projects does add to rate base. More importantly, the proposed grid modernization investments, which are at least fifty times greater than all historical NEM upgrades, would hugely increase SCE's rate base and profits. If these investments are primarily intended to offset upgrades that would otherwise be funded by wholesale developers, such a proposal represents a huge shift in cost responsibility. More importantly, it would be incredibly wasteful, since wholesale developers would presumably only fund upgrades for actual projects, whereas SCE intends to modernize many circuits irrespective of future wholesale project growth and location.

I worry that rather than accurately scoping and completing all upgrades necessary to interconnect wholesale projects, SCE seeks to preemptively "modernize" many of its circuits so as to increase rate base rather than have wholesale developers pay for necessary upgrades. This result is disturbing, especially since TURN was a strong supporter of so-called "wholesale distributed generation," and supported procurement mechanisms such as the RAM and the ReMAT for distributed wholesale projects. The Commission has adopted a pilot cost certainty envelope for interconnection estimates for wholesale generators, with the expectation that cost certainty will reduce financing costs and benefit ratepayers due to lower PPA prices.[38] That may

[38] D.16-06-052, Finding of Fact 10, p. 43.

be true; however, ratepayers will in no way benefit if SCE preemptively spends hundreds of millions to upgrade and automate circuits in anticipation of wholesale generation.

7.4 SCE's Pilot DER Procurement Makes No Economic Sense

One of the primary alleged benefits of DG is the elimination of utility distribution capacity investments intended to account for load growth. These are some of the investments SCE details in the system planning volume, SCE02v3. The Commission has long recognized that DG that satisfies the "right time, right place, and right amount" criteria could offset distribution capacity investments. However, utilities have increasingly complained that the impacts of DG on the distribution system require additional investments to deal with issues such as two-way flow and masked load. In the DRP proceeding, TURN has repeatedly voiced our concern that the purported costs to accommodate more DG must be compared to the benefits of additional DG.

Unfortunately, our concern is apparently justified even more than we feared by SCE's proposed Distribution Project Deferral Pilot to procure DERs to offset eight potential distribution capacity projects.[39]

The total capital cost of the eight distribution projects that would be deferred by DERs is "approximately $40 million in capital." SCE states that the eight proposed projects span 74 of the 264 circuits that are part of the DER portion of distribution automation. At more than $1 million per circuit,[40] the distribution automation work driven by these eight pilots will thus about $80 million, or twice the cost of the projects the DERs are intended to avoid. Mr. Stephens shows that even if one includes the additional reliability benefits due to distribution automation, there is

[39] SCE02v3, p. 48-40 and WP SCE02v3R, p.1-9.

[40] Just the "distribution automation" portion of grid modernization is approximately $285 million per year for 2018-2020, or almost exactly $1 million per circuit. The scope of work of DA is exactly the same for WCR and DER circuits. These costs do not include the additional $265 million per year for the other components of grid modernization (mainly SA-3, FAN, WAN, and GMS).

still a large disconnect between the supposed avoided costs due to DERs and the investment costs necessary to support DERs.

ORA witness Roberts noted that from a policy perspective, SCE's proposal for eight pilots is entirely inconsistent with the goals of R.14-08-013, which authorized just one of the pilots, and R.14-10-003, which intends to evaluate exactly how to perform such a pilot cost effectively. I fully agree with Mr. Roberts.

From a high level perspective I see two possibilities. If SCE is correct that it must modify each circuit with $1 million before it can "procure DERs" for those circuits, then it makes absolutely no sense to "procure DERs" as a method of deferring distribution capacity spending. SCE should do its distribution capacity investments, and DERs should continue based on organic adoption without any specific "procurement" or grid modernization. However, if SCE is simply wrong that all of those circuits must be modernized in the way it proposes, then DER procurement could go forward without the associated distribution automation of all the circuits.

The testimonies of TURN witnesses Alvarez and Stephens suggest that the more likely outcome is the second – that SCE is overly aggressive in its forecast of necessary grid automation work. SCE can deal with potential problems associated with DERs by implementing a more limited program that provides greater intelligence and remote switching capabilities, without the automation capabilities requested by SCE. Their testimony suggests that DERs can be accommodated more cost-effectively, thus promoting California's clean energy goals and providing net benefits to ratepayers.

8 Equity Issues Related to Reliability on 4 kV Circuits

SCE contends that eliminating 4 kV circuits is a matter of equity. SCE calculates that 26% of all its customers live in disadvantaged communities, but 44% of the households served by 4 kV circuits are in disadvantaged communities. However, SCE finds that the distribution of low-income CARE/FERA customers on 4 kV circuits is very similar to the distribution on all other circuits, with 29% of customers on all circuits enrolled in CARE/FERA and 32% of the customers on 4 kV circuits enrolled on CARE/FERA.[41]

I appreciate that SCE is paying attention to equity issues. I offer two observations. First, I place greater weight on the distribution of low-income customers as a matter of economic and environmental justice. Those customers are the ones who are disproportionately impacted by utility costs as well as the distribution of environmentally polluting facilities. While there are some useful elements of the CalEnviroScreen 2.0 tool, it is a model that incorporates environmental criteria (air quality, traffic) that can make an urban area with significant car traffic qualify as a disadvantaged community, despite the presence of high income residents and no disproportionate polluting facilities (aside from cars). I do not view improving *electric reliability* in such areas as inherently an environmental justice issue. Improving electric reliability is different from reducing pollution due to a disproportionate concentration of polluting industries. Indeed, if the cost of improving reliability is very high, I am concerned that we could be harming the low-income customers we are supposed to be helping. Expanding a 4 kV elimination program that is not cost-effective from a reliability perspective may be just such an example of a counterproductive program.

Second, SCE provided the following data concerning the distribution of different circuits in disadvantaged communities (DACs):

[41] SCE02v3, p. 76:8-13.

Table 4: Distribution of Circuits in Disadvantaged Communities (DAC)[42]

DAC RESULTS

	Yes	None	Partial
<5 kV	9.41%	81.48%	9.11%
>5 kV	6.70%	70.02%	23.28%

These numbers show that a higher percentage of the 4 kV circuits (81%) are not in DACs as compared to the higher voltage circuits (70% not located in DACs). These results, combined with the Company's data regarding the distribution of low-income customers, lead me to recommend that the Commission should not reach any conclusions regarding the environmental or economic justice impacts of improving reliability on 4 kV circuits.

Nevertheless, TURN took into account these issues when analyzing the cost-effectiveness of the 4 kV elimination program. Mr. Stephens looked closely at the 4 kV circuits where the cost-effectiveness numbers were closer to one than on average, meaning the reliability benefits almost offset the costs, to determine whether their presence in a disadvantaged community could be an additional qualitative factor to support conversion of the substation. He found, however, that few of the first 200 4 kV circuits targeted for elimination (for reasons other than overloading) were entirely in DACs, and none of those had a benefit-cost ratio even close to 1.0.

This concludes my prepared direct testimony.

[42] DR TURN-078-24.

ATTACHMENTS

Attachment 1	Hawiger CV
Attachment 2	Wholesale distributed solar generation projects
Attachment 3	SCE Data Responses Cited in Testimony (excluding data spreadsheets)

ATTACHMENT 1

Statement of Qualifications: Marcel Hawiger

My current position is Staff Attorney at TURN. I have held this position since August of 1998. I have represented TURN as the attorney of record in numerous energy proceedings since 1998, including general rate cases, electric and gas procurement cases, asset-specific applications and proceedings related to demand-side management programs and budgets. I am a member of the Procurement Review Groups for all three IOUs.

Prior to my employment with TURN I was the Director of MidPeninsula Citizens for Fair Housing (1996-1998). I have also been employed by Evergreen Legal Services (1994-1996), the Massachusetts Department of Environmental Protection (1988-1990) and GHR Engineering, Inc. (1986-1988).

My education includes a Bachelor of Science degree in Geology from Yale University, a Master of Science degree in Civil and Environmental Engineering from Cornell University, and a law degree from New York University.

I have testified previously before this Commission in the following proceedings: Rulemaking 13-09-011 concerning demand response policies; Investigation 12-01-007 concerning the San Bruno natural gas pipeline explosion; Investigation 10-11-003 concerning the Rancho Cordova natural gas pipeline explosion; Application 08-03-015 concerning SCE's Photovoltaic Program; and Application 14-04-014 regarding SDG&E's electric vehicle infrastructure program.

ATTACHMENT 2

Wholesale Solar Projects Connected to Distribution System (DR TURN-09-06d)

Project Number	Technology	Facility Max Export Req(MW)	Facility County	Circuit ID	System ID	Substation ID
WDT356	Photovoltaic	1.5	San Bernardino	Bacardi 12kV	Mira Loma 220/66	Milliken 66/12 (D)
WDT358	Photovoltaic	2	San Bernardino	Bacardi 12kV	Mira Loma 220/66	Milliken 66/12 (D)
WDT450	Photovoltaic	1	San Bernardino	Bacardi 12kV	Mira Loma 220/66	Milliken 66/12 (D)
WDT451	Photovoltaic	1	San Bernardino	Bacardi 12kV	Mira Loma 220/66	Milliken 66/12 (D)
WDT762ISP	Photovoltaic	0.49	San Bernardino	Bacardi 12kV	Mira Loma 220/66	Milliken 66/12 (D)
WDT384	Photovoltaic	2.5	San Bernardino	Benny 12kV	Etiwanda 220/66	Etiwanda 66/12 (D)
WDT403	Photovoltaic	2	Los Angeles	Big Pines 12kV	Antelope 220/66	Little Rock 66/12 (D)
WDT640	Photovoltaic	5	Los Angeles	Big Pines 12kV	Antelope 220/66	Little Rock 66/12 (D)
WDT367	Photovoltaic	3	San Bernardino	Calabash 12kV	Etiwanda 220/66	Declez 66/12 (D)
WDT375	Photovoltaic	1.5	San Bernardino	Calabash 12kV	Etiwanda 220/66	Declez 66/12 (D)
WDT754ISP	Photovoltaic	0.49	San Bernardino	Calabash 12kV	Etiwanda 220/66	Declez 66/12 (D)
WDT327	Photovoltaic	1	San Bernardino	Calmen 12kV	Chino 220/66	Chino 66/12 (D)
WDT368	Photovoltaic	5	Kern	Carbon 12kV	Windhub 220/66	Goldtown 66/12 (D)
WDT387	Photovoltaic	4.5	San Bernardino	Casmalia 12kV	Etiwanda 220/66	Alder 66/12 (D)
WDT759ISP	Photovoltaic	1.5	San Bernardino	Casmalia 12kV	Etiwanda 220/66	Alder 66/12 (D)
WDT650	Photovoltaic	2	San Bernardino	Cement 33kV	Victor 220/115	Victor 115/33 (D)
WDT651	Photovoltaic	2	San Bernardino	Cement 33kV	Victor 220/115	Victor 115/33 (D)
WDT365	Photovoltaic	2.5	San Bernardino	Centaur 12kV	San Bernardino 220/66	San Bernardino 66/12 (D)
WDT373	Photovoltaic	1.5	San Bernardino	Centaur 12kV	San Bernardino 220/66	San Bernardino 66/12 (D)
WDT378	Photovoltaic	2	San Bernardino	Centaur 12kV	San Bernardino 220/66	San Bernardino 66/12 (D)
WDT612	Photovoltaic	1	San Bernardino	Centaur 12kV	San Bernardino 220/66	San Bernardino 66/12 (D)
WDT613	Photovoltaic	1	San Bernardino	Centaur 12kV	San Bernardino 220/66	San Bernardino 66/12 (D)
WDT614	Photovoltaic	0.5	San Bernardino	Centaur 12kV	San Bernardino 220/66	San Bernardino 66/12 (D)

WDT462ISP	Photovoltaic	8	Riverside	Chaney 12kV	Valley 'AB' 500/115	Bunker 115/12 (D)
WDT263	Photovoltaic	21	Riverside	CHANSLOR 33KV	Blythe (WALC) 161/33	Blythe City 33/33 (D)
WDT461	Photovoltaic	5	Kern	Cloer 12kV	Vestal 220/66	Poplar 66/12 (D)
WDT402	Photovoltaic	10	Kern	Discovery 12kV	Windhub 220/66	Goldtown 66/12 (D)
WDT388	Photovoltaic	2	San Bernardino	Dorsey 12kV	Etiwanda 220/66	Alder 66/12 (D)
WDT409	Photovoltaic	10	San Bernardino	DRYLANDS 33KV	Victor 220/115	Cottonwood 115/33 (D)
WDT421	Photovoltaic	20	San Bernardino	DRYLANDS 33KV	Victor 220/115	Cottonwood 115/33 (D)
WDT363	Photovoltaic	2.5	San Bernardino	Durox 12kV	San Bernardino 220/66	Timoteo 66/12 (D)
WDT752ISP	Photovoltaic	1	San Bernardino	Durox 12kV	San Bernardino 220/66	Timoteo 66/12 (D)
WDT473FT	Photovoltaic	1.75	San Bernardino	Earnhardt 12kV	Padua 220/66	Cucamonga 66/12 (D)
WDT854FT	Photovoltaic	1.5	San Bernardino	Flue 12kV	Victor 220/115	Aqueduct 115/12 (D)
WDT1057FT	Photovoltaic	1	San Bernardino	Graf 12kV	Etiwanda 220/66	Wimbledon 66/12 (D)
WDT444	Photovoltaic	1.6	Los Angeles	Gridlock 12kV	Walnut 220/66	Nogales 66/12 (D)
WDT423	Photovoltaic	2	San Bernardino	Melody 25kV	Devers 220/115	Hi Desert 33/25 (D)
WDT884ISP	Photovoltaic	4.95	San Bernardino	Minotaur 12kV	San Bernardino 220/66	San Bernardino 66/12 (D)
WDT1053FT	Photovoltaic	1.49	Riverside	Nozzle 12kV	Chino 220/66	Firehouse 66/12 (D)
WDT481	Photovoltaic	1.25	Los Angeles	Orchardale 12kV	Del Amo 220/66	Carmenita 66/12 (D)
WDT1051FT	Photovoltaic	1.49	Riverside	Plummer 12kV	Valley 'AB' 500/115	Cajalco 115/12 (D)
WDT786	Photovoltaic	20	Riverside	Resort 33kV	Valley 'AB' 500/115	Nelson 115/33 (D)
WDT359	Photovoltaic	2.5	San Bernardino	Seagrams 12kV	Mira Loma 220/66	Milliken 66/12 (D)
WDT364	Photovoltaic	1	San Bernardino	Seagrams 12kV	Mira Loma 220/66	Milliken 66/12 (D)
WDT459	Photovoltaic	9	San Bernardino	Sheephole 33kV	Devers 220/115	Hi Desert 115/33 (D)
WDT639	Photovoltaic	5	Los Angeles	Snowden 12kV	Antelope 220/66	Del Sur 66/12 (D)
WDT360	Photovoltaic	1.5	San Bernardino	Speedway 12kV	Etiwanda 220/66	Declez 66/12 (D)
WDT374	Photovoltaic	3	San Bernardino	Speedway 12kV	Etiwanda 220/66	Declez 66/12 (D)
WDT755ISP	Photovoltaic	3.49	San Bernardino	Speedway 12kV	Etiwanda 220/66	Declez 66/12 (D)
WDT480	Photovoltaic	1.166	Los Angeles	Studebaker 12kV	Del Amo 220/66	Carmenita 66/12 (D)
WDT426	Photovoltaic	1.5	San Bernardino	Tigercat 12kV	Chino 220/66	Kimball 66/12 (D)

WDT440	Photovoltaic	5	Riverside	Tram 33kV	Devers 220/115	Garnet 115/33 (D)
WDT351	Photovoltaic	1.5	San Bernardino	Unicorn 12kV	San Bernardino 220/66	San Bernardino 66/12 (D)
WDT352	Photovoltaic	1.5	San Bernardino	Unicorn 12kV	San Bernardino 220/66	San Bernardino 66/12 (D)
WDT611	Photovoltaic	1	San Bernardino	Unicorn 12kV	San Bernardino 220/66	San Bernardino 66/12 (D)
WDT525	Photovoltaic	1	Riverside	Vicentia 12kV	Mira Loma 220/66	Corona 66/12 (D)
WDT389	Photovoltaic	3	San Bernardino	Warm Creek 12kV	San Bernardino 220/66	Cardiff 66/12 (D)
WDT761ISP	Photovoltaic	0.99	San Bernardino	Warm Creek 12kV	San Bernardino 220/66	Cardiff 66/12 (D)
WDT347	Photovoltaic	1	San Bernardino	Zinfandel 12kV	Vista 220/115	Pepper 115/12 (D)
WDT433	Photovoltaic	40	Tulare		Vestal 220/66	
WDT1041ISP	Photovoltaic	5	Riverside			

ATTACHMENT 3

SCE Data Responses (text only)

Please see separate Exh. TURN-10-A