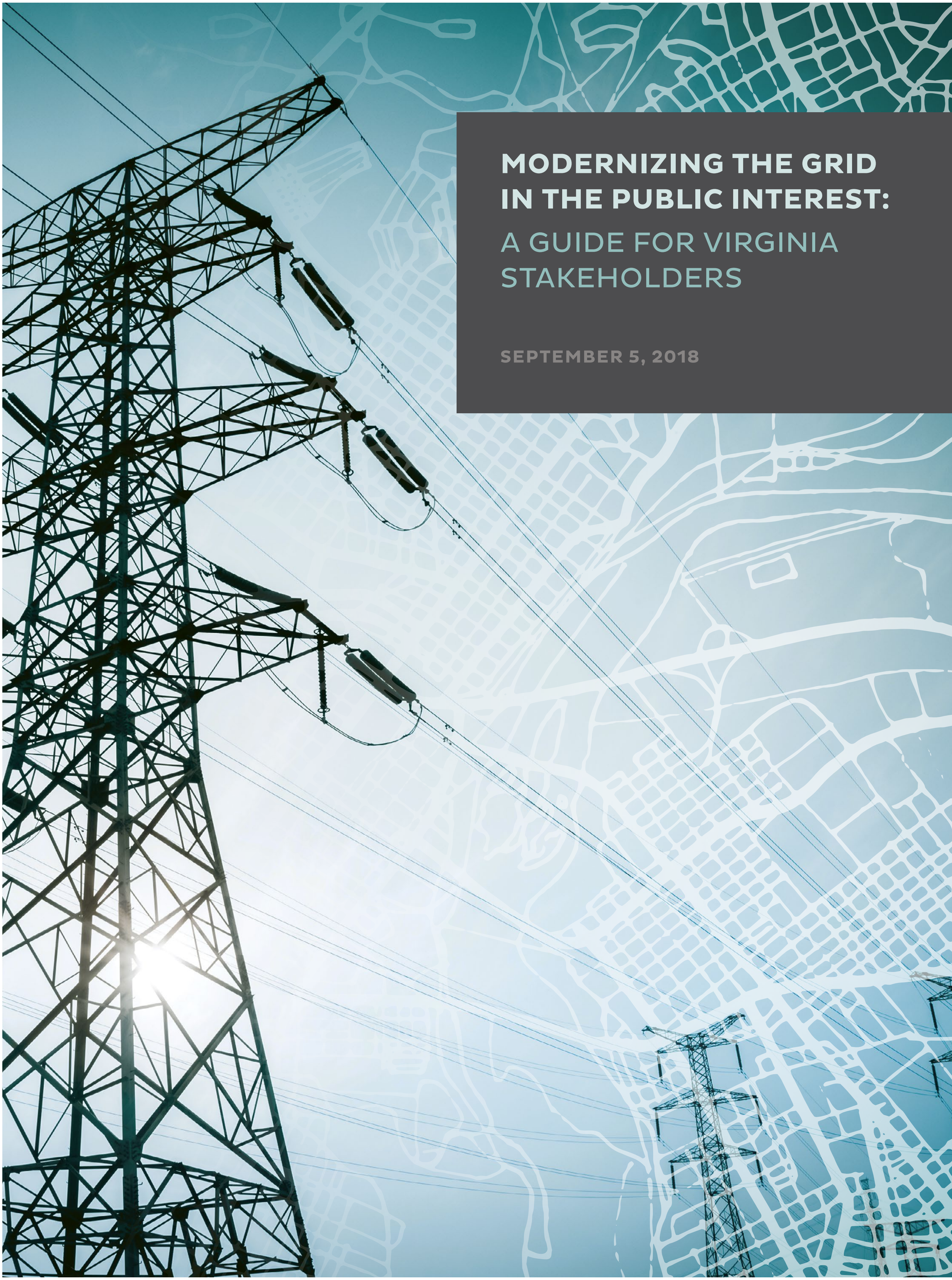

MODERNIZING THE GRID IN THE PUBLIC INTEREST:

A GUIDE FOR VIRGINIA STAKEHOLDERS

SEPTEMBER 5, 2018

ABOUT GRIDLAB

GridLab is a non-profit organization which provides comprehensive and credible technical expertise on the design, operation, and attributes of a flexible and dynamic grid to assist policy makers, advocates, and other energy decision makers to formulate and implement an effective energy transformation roadmap. GridLab offers technical expertise, training, and a connectivity platform for sharing information about the rapidly-evolving electric distribution grid landscape.

ABOUT THE AUTHORS

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A number of Virginia stakeholders and industry experts made significant contributions to this paper. They include **Mr. Harry Godfrey**, Executive Director, Virginia Advanced Energy Economy; **Dr. Caroline Golin**, Regulatory Director, Vote Solar; and **Mr. Ric O'Connell**, Executive Director, GridLab.

This paper includes statements complimentary to some modern grid technologies, namely Advanced Distribution Management Systems, Distributed Energy Resource Management Systems, Integrated Volt-VAr Optimization, and smart phone energy management applications. None of the authors or contributors owns equity in any service provider in these industries, nor is being nor has been compensated by any service provider or association of service providers in these industries.

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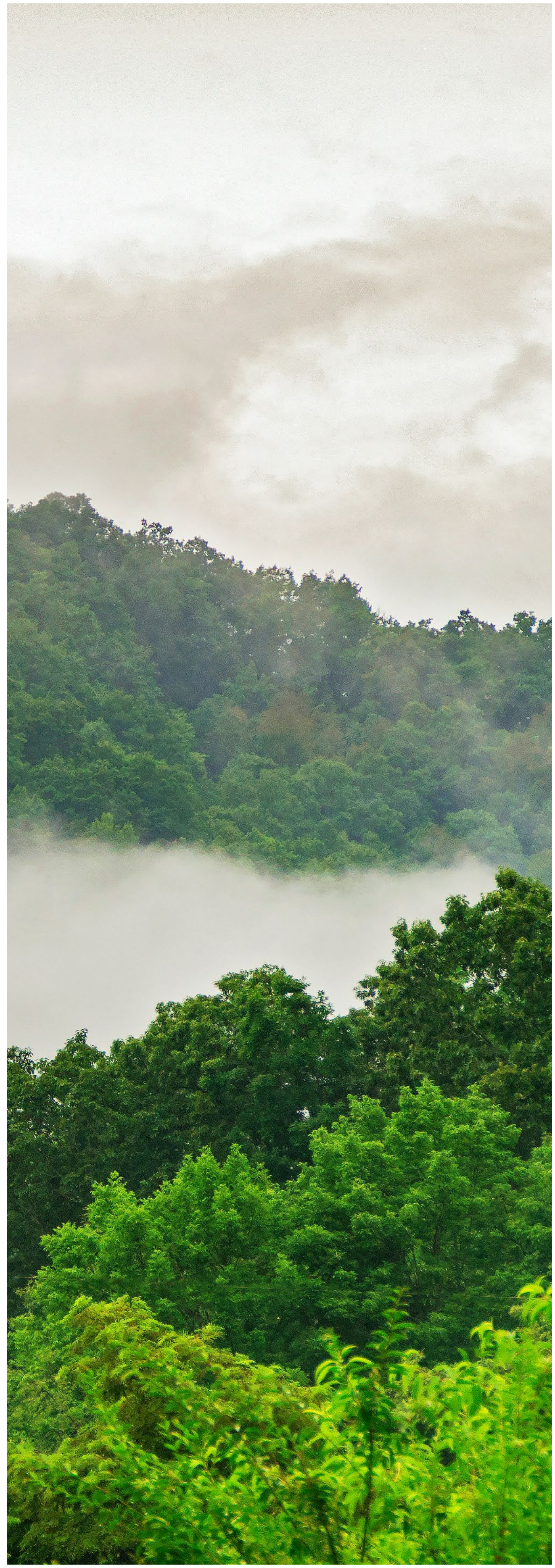


EXECUTIVE SUMMARY

Utilities across the world are taking steps to modernize their electric grids. In the most basic sense, this means augmenting the grid with software and communications technologies to help the grid meet the new demands society is placing upon it. States serious about grid modernization are taking a thoughtful and methodical approach through dedicated investigational proceedings – a reflection of the enormous capital expenditures about to be made, and the enormous consequences of mistakes.

Grid modernization offers many potential benefits if designed and executed well, but also the potential to waste customer money if designed poorly. In short, there is wide variability in grid modernization results from utility to utility and a dearth of objective outcomes research. In Virginia, the potential for missteps are even greater than in most states, due in part to the unique use of a stockpile of excess earnings as an optional funding mechanism. Virginia's Grid Transformation and Security Act (GTSA), and the subsequent filing of Phase 1 of Dominion's Grid Transformation Plan, has forced Virginia regulators and stakeholders to quickly consider a host of issues in which our collective experience is extremely limited.

Virginia may wish to consider what a "no regrets" grid modernization plan looks like, using the experiences of other states as a guide. To summarize, a "no regrets" grid modernization plan is characterized by the cost-effective implementation of the most critical capabilities, to an appropriate geographic extent, utilized in a manner which maximizes available economic benefits, accommodates customer choices, and delivers the greatest return on investment for consumers and the environment. There are concrete grid modernization steps (planning, execution, and oversight) Virginia can take to make these positive outcomes more likely; conversely, skipping these steps makes poor outcomes likely.

Evidence and anecdotes make a compelling case for doing grid modernization right. To summarize, foundational software should generally come first, with geographic expansions in grid hardware pursued only as need is demonstrated through a transparent planning process. Smart meters can serve critical roles in a modern grid, and can be installed for no net cost to customers if care is taken to maximize available benefits. This general construct can contain appropriate variation, with individual utility and state characteristics

having a significant impact on capabilities and performance measures. Demonstrated value creation varies widely in grid modernization projects completed to date; benefits are contingent upon each utility's technology choices, and how well each utilizes available capabilities once deployed.

For the layperson, the purchase of a smart phone provides a relevant analogy to grid modernization. A consumer can spend $900 on a smart phone if he or she chooses. But if the consumer doesn't identify in advance the capabilities he or she values the most, or doesn't evaluate how well various models deliver on those capabilities, or fails to dismiss models with features he or she may not need for several years (if ever), he or she will likely spend much more on a smart phone than necessary. Furthermore, once an appropriate model is identified and purchased, additional efforts are required to maximize the value of available features; failure to do so will sub-optimize the benefits of the purchase.

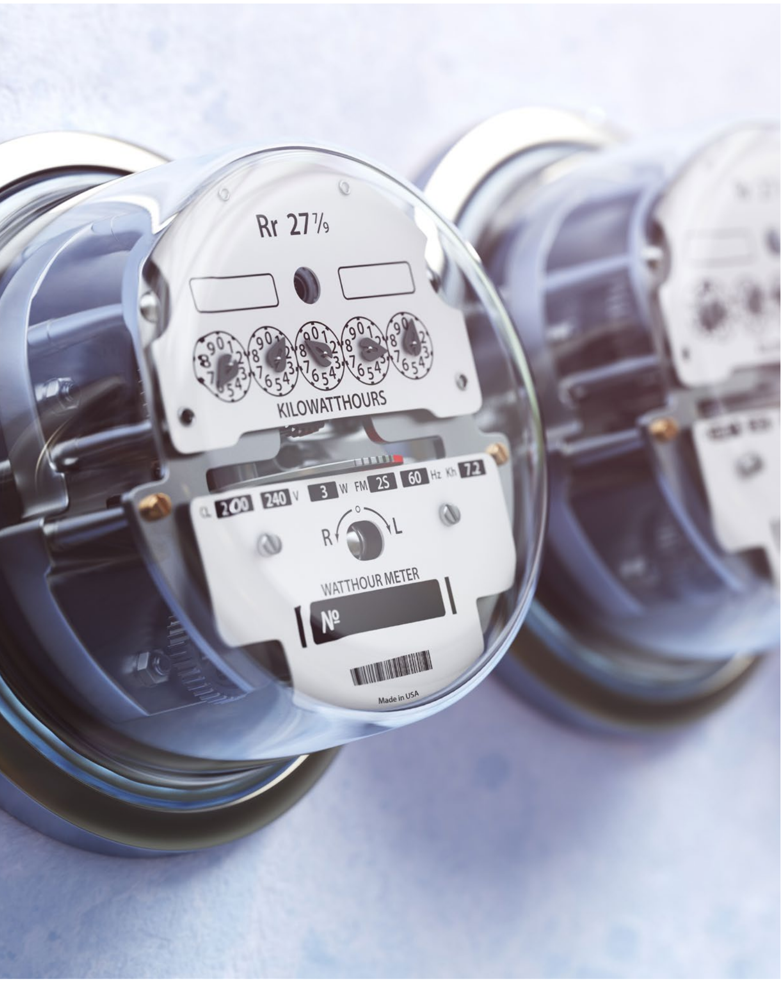
Dominion's Grid Transformation Plan fares poorly in comparison to the ideal plan and the smart phone analogy, with most deficiencies traceable directly to the current regulatory construct:

- Several critical capabilities (most related to conservation), and associated benefits, are missing from the Plan entirely;
- Benefit-cost analyses indicating net customer benefits are highly questionable;
- While the benefits of grid modernization are known to vary widely from utility to utility, there are no performance metrics, targets, or benefit assurances from Dominion;
- The Plan offers no ongoing grid planning process despite substantial industry changes, dramatic increases in economic and technology risk, and significant optionality;
- The single largest Plan component – $1.5 billion in "grid hardening" – is not grid modernization at all, but traditional utility infrastructure, offering little to no quantifiable increase in grid resilience, reliability, or distributed generation capacity;
- The $500 million communications network proposal is overpriced and antiquated, considering neither 3rd party options, nor recent developments in wireless communications, nor the rapidly-approaching "Internet of Things".

While this paper is critical of Dominion's Grid Transformation Plan, it is not meant to discourage grid investment. Rather, this paper intends to stimulate the stakeholder interest and engagement required for cost-effective grid modernization and post-deployment benefit maximization. Grid modernization should not be a one-time event designed to take advantage of an unexpected cache of recently-discovered resources (i.e., Virginia IOUs' accumulated excess earnings). Rather, grid modernization is a long-term process which requires new roles for, and demands greater commitments from, all stakeholders. In the long term, fundamental changes to utility capital bias and the throughput incentive may be required. But today, sound grid planning and carefully considered utility investments, combined with extensive post-deployment efforts and performance measurement, can fill the gap and help avoid abuse of the public trust.

In summary, before Virginia stakeholders buy that smart phone, they need to educate themselves on features and benefits. They also need to commit themselves in advance to the post-purchase efforts required to maximize smart phone satisfaction.

GRID MODERNIZATION IN VIRGINIA: AN INTRODUCTION



The Grid Transformation and Security Act was signed into Virginia law on March 9th, 2018. The Act covered a range of energy topics in the Commonwealth, from the regulation of energy efficiency to the deployment of renewable generation. It established important goals for clean energy. But central to the Act is a provision permitting Virginia's investor-owned utilities (IOUs)[1] to invest a portion of their overearnings — the result of an ill-conceived rate-freeze three years' prior — into "grid transformation" projects in lieu of bill credits to Virginia ratepayers.

The definition of "transformation" projects included in the Act is broad, ranging from LED street lights to undergrounding of overhead distribution lines. Included therein are technologies which can, under the right conditions and with necessary post-deployment effort and oversight, deliver a grid that will correctly anticipate the future needs of Virginia's economy at a reasonable cost. Also included therein is the potential to squander a one-time opportunity, saddling Virginia's economy with electric distribution costs which, in retrospect, would have been better spent on other capabilities or customer refunds.

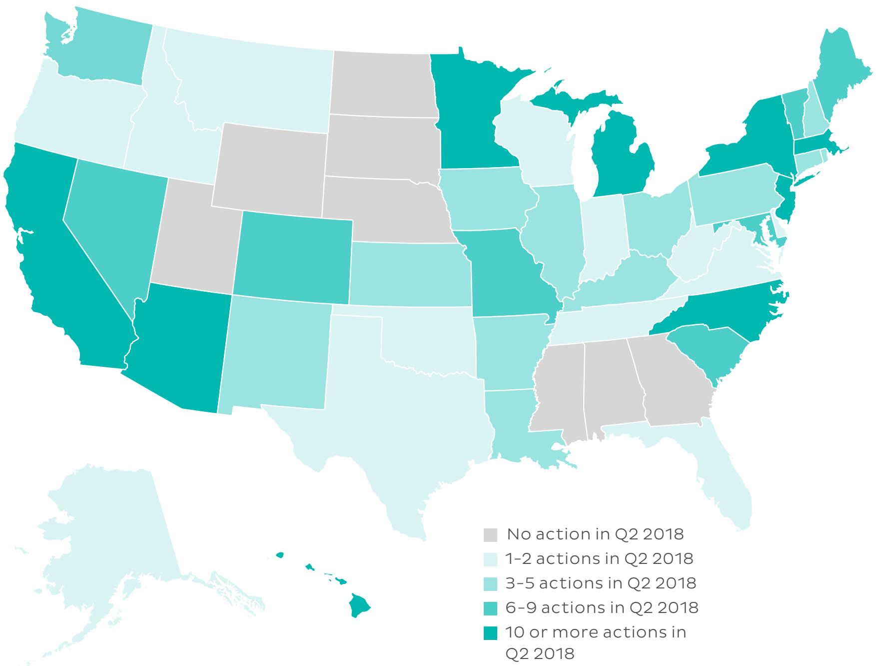
Grid modernization can unleash a 21st century energy system in the Commonwealth, to the benefit of Virginia's economy, environment, and pocketbooks. But will it? That is the question facing the Commonwealth today. Other states have embarked on grid modernization through deliberate processes, defining objectives and cementing regulations before deploying technologies. The passage of this Act, and the subsequent filing of Phase 1 of Dominion's Grid Transformation Plan, has thrust Virginia regulators, policymakers, advocates, and consumers into the middle of a complicated, and potentially ill-informed, investment evaluation process.

This paper is an attempt to moderate risks and maximize customer benefits through stakeholder education and engagement. This introduction continues by describing the opportunities made available by grid modernization, as well as what could go wrong and a summary of grid modernization results to date. The paper then describes the contents of a "no regrets" grid modernization plan, informed by lessons learned in other states. An evaluation of Dominion's Grid Transformation Plan follows, providing stakeholders with valuable information on how to improve upon it. The paper concludes with a call to action. When it comes to grid modernization, long-term commitments of effort from stakeholders, regulators, customers, and utilities are required to optimize investments, maximize benefits, reduce risk, and avoid waste.

GRID MODERNIZATION OPPORTUNITIES AND RISKS

Several state utility regulators are conducting investigational or litigated proceedings related to grid modernization. Many of these proceedings were prompted by large utility capital investment requests, while others were prompted by state legislatures, or by regulators themselves through their own initiative. Though legislators and regulators in other states may be wondering what all the fuss is about, there is a growing recognition that some amount of grid modernization is necessary and valuable. Drivers of this recognition are described below.

FIGURE 1. *Q2 2018 Legislative and Regulatory Action on Grid Modernization*



Promote Economic Development

- Low electric rates, achieved through cost-effective grid investment and high grid asset utilization (more electricity with fewer assets), spurs commercial and industrial activity and creates jobs.
- Distributed energy resources (DER, such as rooftop solar and storage)[2] are already cost effective in many instances and create jobs (the solar energy industry alone employed 260,000 Americans in 2016).[3]
- Risks: Cost-ineffective grid investments, or failure to maximize the benefits from grid investments, will result in unnecessarily high electric rates.

Improve Reliability and Resilience

- Some of the same investments designed to increase grid DER capacity and asset utilization also improve grid reliability and resilience.
- Risks: Some grid investments proposed as reliability and resilience improvements (undergrounding, hardening) offer very low (if any) benefits per dollar, resulting in higher electric rates with little or no improvement.

Accommodate Customer DER and Electrification Choices

- As costs fall, more and more customers become interested in owning DER and electric vehicles (EV).
- Appropriate technology investments can prepare grids for high levels of DER and EV, thereby avoiding limitations on customer choice.
- Risks: Investments made to a greater geographic extent/earlier than necessary will result in unnecessarily high electric rates.

Encourage Energy Capitalism and Democracy

- "Prosumers" (early adopters of DER and EV) are getting more sophisticated. Some are interested in being compensated for services they could offer to the utility and to other customers.
- In some cases, these alternative providers may be able to deliver services more cheaply than a utility, or to help avoid a utility investment (such as a substation or circuit capacity upgrade).
- Risks: Utilities will oppose these actions as threats to their monopoly and shareholder interests, even in cases where economically beneficial to customers.

Cost-Effective Reduction in Environmental Impact

- Virginia is considering joining the Regional Greenhouse Gas Initiative (RGGI), which requires carbon emitters (like electric power stations fueled by coal or natural gas) to pay a price per ton of CO_2 emitted.
- A more energy-efficient grid, or a grid capable of accommodating greater levels of renewable DERs and electric vehicles, reduces the cost to comply with environmental goals.

- Risks: If IOUs spend more than necessary to accommodate DER and EV, environmental concerns may be inaccurately associated with high costs.

GRID MODERNIZATION: THE STORY SO FAR

Like most endeavors, there is a right way and a wrong way to modernize electric distribution grids. Surprisingly, only three objective, post-deployment evaluations of smart grid deployments have been completed.[4] A review of these evaluations indicates that deployment costs are generally higher than anticipated, that customer benefits are generally lower than projected, and that the benefits delivered by any given modern grid capability vary widely from utility to utility.

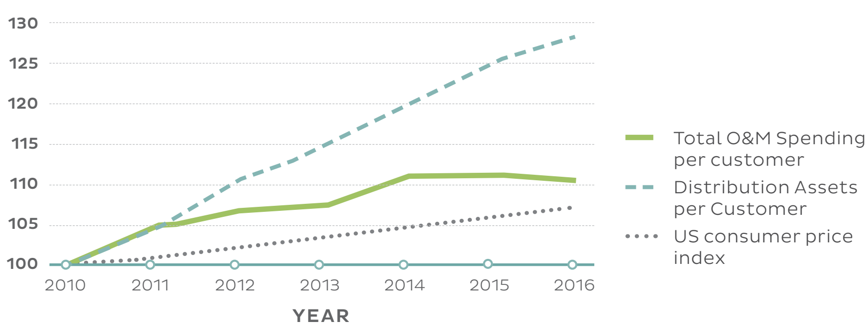
The nature of utility compensation helps to explain these findings. Utilities maximize profits by maximizing investment (called *capital bias*). No US utilities are compensated based on the value grid investments deliver. As a consequence, utilities are very concerned about maximizing investment, and much less concerned about value creation.

A review of publicly-available financial and operating data from US utilities appears to validate the findings of the three smart grid deployment evaluations. In 2010, the book value of distribution grid assets per US utility customer was $2,900.[5] By 2016, the book value per customer had grown to $3,785 per customer[6] – a compound annual growth rate of about 4.5%, or more than triple that of the US consumer price index over the same period. To date, however, the same data sources indicate that US consumers have little to show for these investments in terms of operations and maintenance (O&M) spending reductions or reliability improvements. (Charts courtesy of the Utility Evaluator™).

To summarize, what Virginia needs from Dominion and Appalachian Power are "no regrets" grid modernization plans. "No regrets" grid modernization plans are characterized by the cost-effective implementation of the most critical capabilities, to an appropriate geographic extent, utilized in a manner which maximizes available economic benefits, accommodates customer choices, and delivers the greatest return on investment for consumers and the environment. The next section of the whitepaper describes what stakeholders should look for in "no regrets" grid modernization plans.

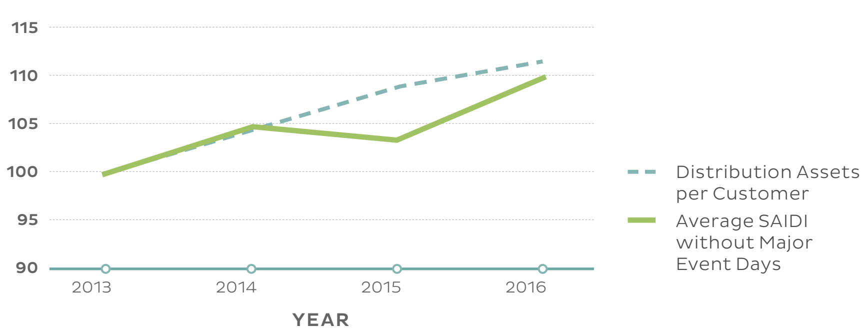
SELECTED DATA, ALL US IOUs, 2010=100

Data sources: FERC Form 1; EIA Form 861



SELECTED DATA, ALL US IOUs, 2013=100

Data sources: FERC Form 1; EIA Form 861



WHAT A "NO REGRETS" GRID MODERNIZATION PLAN INCLUDES

As Virginia is arriving somewhat late to grid modernization planning, lessons learned in other states can be helpful. The contents and characteristics of a "no regrets" grid modernization plan as collected from other states' experiences include:

- A business case in which customer benefits exceed customer costs
- Software to improve grid reliability, resilience, and DER hosting capacity
- Software to improve grid energy efficiency
- Grid planning processes (appropriate geographic expansion of software capabilities)
- Smart meters (if indicated by a favorable customer benefit-cost analysis)
- Distribution grid and business performance metrics

A BUSINESS CASE IN WHICH CUSTOMER BENEFITS EXCEED CUSTOMER COSTS

Virginia's Grid Transformation and Security Act does not require the customer benefits of grid modernization projects to exceed customer costs. However, the Act does give the State Corporations Commission (SCC) the authority to approve or deny utility grid modernization plans, and requires such plans to be "reasonable and prudent".[7] Though "public convenience and necessity" rules apply only to proposed electric generation facilities, Virginia law requires construction and operation of generation facilities to be "required by the public convenience and necessity".[8] As Virginia utilities already have adequate grids, it could be implied that either incremental Plan benefits should exceed incremental Plan costs, or that public convenience and necessity be required, for such Plans to clear the reasonable and prudent hurdle.

Grid modernization business cases in general, and benefit-cost analyses specifically, are also useful for holding utilities accountable for costs and benefits. Without objective, scrutinized projections of the benefits (economic, reliability, etc.) from grid modernization investments, or sound cost estimates, how can customers know if a grid modernization investment was successful or not?

Having established that favorable benefit-cost analyses are reasonable requirements for grid modernization plans in Virginia, we identify the deficiencies most commonly found in US utilities' grid modernization benefit-cost analyses.

Aggressive Benefit Projections. If a grid modernization plan offers benefit projections at all, it is likely that the projections are aggressive, best-case scenarios. Utilities which fail to secure aggressive benefit projections generally incur no economic penalty. As a result, all performance risk falls on customers unless regulators order some sort of performance measurement and assurance program as a condition of grid modernization plan approval. Some of the more common issues associated with aggressive benefit projections are described below.

- Projections assume that dollars saved in operating benefits (such as from smart meters) flow to customers every year as realized by the utility. In reality, customers only get a rate reduction when such benefits are reflected in the test year of a rate case after available benefits are fully realized. Such a rate case might not be held for 3, 5, or 10 years post-deployment.
- Benefits are projected over a time period which exceeds expected equipment life. For example, many utilities use a 20-year benefit period to justify the purchase of smart meters which are only expected to last 15 years.
- Many utilities use nominal benefit estimates. Nominal benefit estimates ignore the fact that an economic benefit received 15 years from now is worth much less to a customer than one received next year (owing to inflation/the time value of money). Benefits

anticipated in the future should be estimated in today's dollars (called "Net Present Value") to avoid exaggerating customer benefit size.

- Utilities often express reliability benefit estimates in dollars, which is inappropriate for several reasons. First, failure to make such benefit estimates in minutes of SAIDI[9] makes it difficult to hold utilities accountable for performance. Second, business customers value reliability benefits much higher than residential customers. Third, it hides the tiny size of most reliability benefit estimates. For Dominion, a 1-4% improvement in SAIDI amounts to 1.4 to 5.5 minutes of outage reduction per year.[10]
- Utilities often exaggerate benefit estimates. When estimating theft reduction benefits from smart meters, for example, utilities typically exaggerate the amount of theft that is currently occurring, the percentage of theft cases smart meters can detect, and the dollars collected from thieves (which almost always ignore collection costs, despite the fact that such costs typically amount to $0.50 per $1 collected).

Missing Benefits. Utilities often ignore available electricity conservation benefits in grid modernization plans, as they prefer not to implement programs which will reduce revenues and profits (called the throughput incentive). Frequently missing conservation benefits described later include integrated volt-VAr control, time-varying rates, prepayment programs, and Connect My Data standard compliance.

Underestimated Costs. Two enormous types of costs are missing from virtually every utility's grid modernization cost estimate.

- Customers must pay carrying costs on grid investments, including authorized utility profits on capital, income taxes on utility profits, interest expense on debt, and local property taxes paid on installed equipment. Carrying costs can easily amount to 20 percent or more of total costs, though utilities rarely (if ever) include them in cost estimates.
- Another cost routinely ignored which customers are asked to pay is the book value of assets being removed from service before the end of their useful lives to make way for modern grid assets. This can be significant in smart meter proposals, as a utility's stock of installed meters generally has a sizeable book value. Though customers are being denied the value of old meters retired from service prematurely, utilities make requests of regulators to recover such costs anyway.
- Finally, it is easy for utilities to underestimate costs, as they generally incur no penalty for exceeding budgets. Utilities can underestimate capital requirements or ongoing operations and maintenance costs. Absent gross negligence, which is extremely difficult to prove, customers, not shareholders, bear the risk of cost overruns unless regulators order some sort of risk-sharing arrangement as a condition of grid modernization plan approval.

SOFTWARE TO IMPROVE RELIABILITY, RESILIENCE, AND DER HOSTING CAPACITY

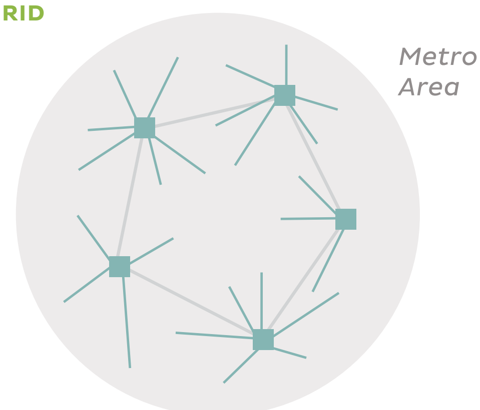
The electric distribution grid was designed to distribute electricity from large, centralized power plants to geographically-diverse customer loads. This grid was designed with no inclination that electricity might travel in the other direction, from customers' DER back towards the generators. Because one-way electricity distribution is an antiquated concept, grid operators require better visibility to grid operating conditions, improved analytical tools, and greater flexibility to reconfigure the grid as needed. Better grid state visibility, analytics, and reconfiguration are not only useful for accommodating DER in a reliable manner; these same capabilities can also improve grid reliability and resilience irrespective of installed DER capacity.

Improved Grid State Visibility. Unbeknown to most laypersons, utilities routinely reconfigure their grids for outage restoration, maintenance, or construction needs. High levels of DER make grid reconfiguration more complicated and increase the risk of error. Better visibility into the status of key grid health indicators (voltage, power factor, power flow/strength/phase balance) can help a grid operator identify optimal reconfigurations with less risk of error. Grid reconfiguration errors can damage grid equipment, cause outages, and create risks to public safety (downed power lines).

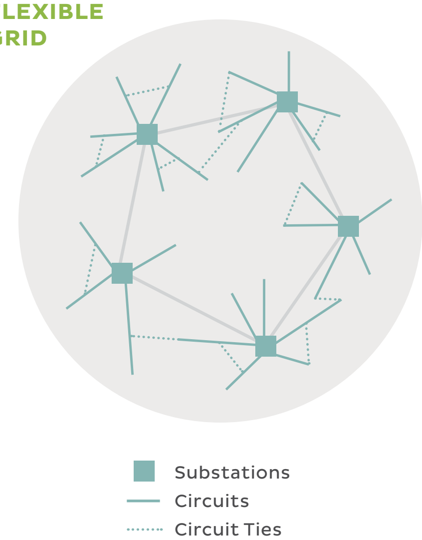
Improved Grid Analytics. With increases in DER and grid visibility come increases in data and the need to translate it into actionable information. Advanced software is available to help grid operators make sound operating and grid configuration choices as grid management complexity increases. Analytical software can model the impact of available grid reconfiguration options in real time. Modeling is also helpful in optimizing long-term grid capacity planning and investment decisions. Finally, modeling can speed the identification of grid upgrades which might be required due to a large-scale, free-standing DER generation project when a third-party developer proposes one.

Increased Grid Configuration Flexibility. Traditional grid design resembles a series of interconnected bicycle wheels, with wheel hubs representing substations, the interconnections representing high-voltage transmission lines, and wheel spokes representing various circuits built to serve homes and businesses. To increase grid configuration flexibility, a utility can build "tie lines" between the spokes to create more of a matrix design, and less of a hub-and-spoke design. A matrix design offers greater grid configuration flexibility, though at significant incremental cost. While an increase in grid configuration flexibility is something stakeholders should look for in a grid modernization plan, the question of how many tie lines to build, and where, requires more extensive analysis (addressed through grid planning, discussed further below).

TRADITIONAL GRID



FLEXIBLE GRID



SOFTWARE TO IMPROVE GRID ENERGY EFFICIENCY

About 5% of the electricity generated by large, centralized power plants is lost by the time the electricity reaches customer loads.[11] While some of this is unavoidable due to the laws of physics, reductions in these "line losses" are possible, and can improve the efficiency of electric distribution. Better balancing of electric phases, improvements in power factor, and conservation voltage reduction are three strategies to improve grid and customer energy efficiency.

While grid operators spend lots of time and effort on these strategies today, they do so periodically (rather than continuously), and estimate the impact of their efforts on grid conditions manually (rather than through the use of software). Furthermore, these strategies are generally executed today in response to problems (reactively), rather than to proactively optimize operations. Grid modernization in general, and grid management software specifically, offers several opportunities to improve distribution energy efficiency. A certain type of software called "Integrated Volt-VAr Optimization" software improves grid efficiency by optimizing, as the name implies, the voltage and VAr (power factor) of electricity delivered to customers. Note that another way to reduce line losses is to locate generation in close proximity to loads (i.e., "distributed" energy resources), thereby avoiding the distribution of electricity and its associated line losses to as great an extent possible.

GRID PLANNING PROCESSES (APPROPRIATE GEOGRAPHIC EXPANSION OF CAPABILITIES)

While grid management software provides grid managers with new tools, the tools are rarely valuable without physical improvements to grid circuits (such as the tie-lines described above); grid equipment (new data collection, reporting, and remote operation capabilities); and communications networks. These physical improvements represent the lion's share of grid modernization costs as compared to software. So the key question becomes, to what geographic extent, at the circuit and/or substation level, should the physical improvements required to secure the benefits of new software be deployed?

In general, the 80-20 rule of thumb (not to be taken literally) applies to the geographic expansion of modern grid software capabilities to the grid through physical improvements. That is, a majority of benefits can be secured by addressing a minority of grid circuits. To illustrate:

- Increases in grid configuration flexibility should be limited to the circuits with the largest numbers of customers (potentially impacted by service outages), or the highest levels of DER generation.
- Integrated Volt-VAr Optimization should be limited to the circuits delivering the largest amounts of energy, or for which the average voltage levels are the highest, or for which the average power factors are the lowest.

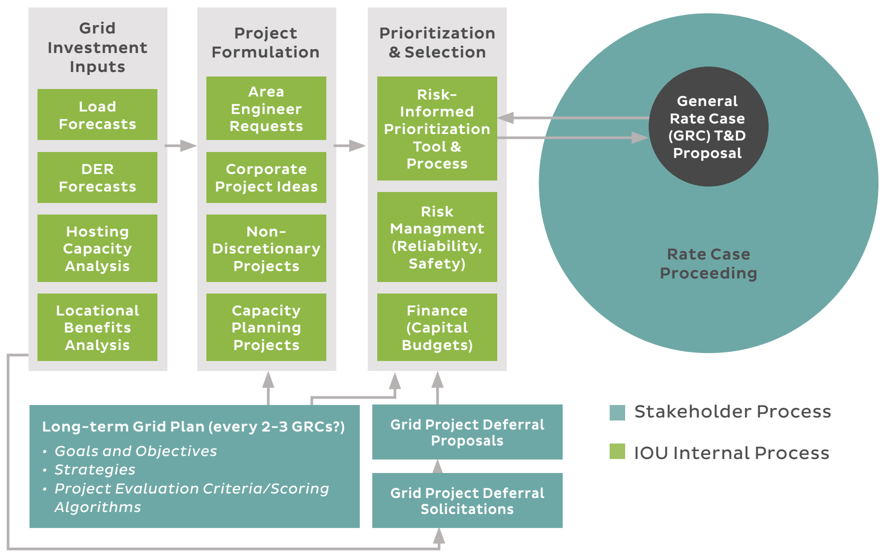
Historically, grid project (physical improvement) selection was a simple process. When economic growth and development necessitated grid extensions or capacity increases, utilities complied. With restrictions on economic development unacceptable, there simply weren't a lot of options available. As long as electricity sales volume growth was expected to pay for it all, conflicts were few. Solutions were comparatively simple, and stakeholder interest was focused elsewhere, typically on generation fleets.

Times have changed. Today, grid projects are selected in an environment characterized by steady or falling electricity consumption; technical complexity; multiple competing priorities; virtually limitless capability and solution options; significant stakeholder interest; and conflict between shareholder and customer interests (like capital bias[12] and the throughput incentive).[13] New conditions call for new grid planning processes, which can also be used to determine the extent to which geographic expansions of modern grid software capabilities should be deployed.

The diagram below presents a periodic grid planning process for consideration. Planning inputs include forecasts for electric load (including EV chargers), DER generation, DER hosting capacity[14], and DER locational benefits.[15] The utility then uses these inputs to develop a list of potential grid projects, estimating the cost and value (in terms of reliability, safety, or other evaluation criteria) of each. "Grid projects" could include just about any project, and should in fact include all projects being contemplated, such as non-discretionary grid investments (to accommodate a new shopping mall or road construction, for example).

From there, the risk-informed decision support software is used to prioritize and select projects, with input from utility risk management and finance functions, and even stakeholders in theory. Capital and operating budgets are developed and proposed in a rate case or other proceeding.

GRIDLAB PROPOSED DISTRIBUTION PLANNING PROCESS



Note that while the grid planning process described will likely result in significant grid investments, it can also help reduce grid investments. It can do so by identifying and delaying projects being considered which deliver less benefit (as defined in the risk-informed decision support software) relative to other projects of similar costs. But a grid planning process can also be used to identify projects which might be deferred or avoided through non-wires alternatives. For example, the cost to increase the capacity of a substation might be deferred or avoided by a combination of demand response, DER generation, and energy storage. In fact, it might make sense for a utility to solicit non-wires alternatives from customers and third parties.

SMART METERS? BENEFITS IN EXCESS OF COSTS CAN BE DIFFICULT TO SECURE

The installation of smart meters is certainly popular, with the Edison Foundation estimating that about 50% of US electric customers now have one.[16] Like other

grid modernization investments, however, the economic benefits from smart meters vary widely from utility to utility, and rigorous examination of most smart meter business cases indicates that a break-even proposition for customers will be difficult to achieve.

Regulators are questioning the smart meter value proposition in an increasing number of states. They recognize that tens of millions of smart meter deployments were approved based on government grants (the American Reinvestment and Recovery Act) which subsidized smart meter costs up to 50%. Regulators are also recognizing that it is difficult to ensure that benefits will exceed costs. So far in 2018, regulators in Kentucky, Massachusetts, and New Mexico have rejected utility proposals to install 2.75 million smart meters due to inadequate customer benefit-to-cost ratios.[17] This is not to suggest that smart meters should be categorically rejected, but it does suggest that smart meter investments are not a "no brainer" decision, and that ongoing efforts are required to ensure that customer benefits from smart meters exceed customer costs.

In the authors' experience, all potential sources of smart meter benefit must be maximized to ensure customer benefits exceed customer costs. An emphasis on post-deployment benefit measurement and accountability is therefore a critical component of any smart meter plan. Another common issue is missing conservation benefits, as utilities have an economic incentive (called the throughput incentive) for selling ever-higher amounts of electricity. As a result, smart meter capabilities with a conservation effect are missing from many utilities' smart meter business cases. These include time-varying rates, prepayment, and compliance with the Connect My Data standard.

Time-Varying Rates. The laws of supply and demand govern wholesale electricity costs just as they do other commodities. When supplies are tight and/or demand is high, wholesale costs rise. When both conditions apply, such as on a hot weekday afternoon with all air conditioners running, wholesale electricity costs rise a lot. In fact, wholesale electricity costs vary 24 hours a day, 365 days a year. However, the laws of supply and demand do not currently apply to Virginia residential customers.

Today, almost all US and Virginia residential electric customers pay a flat rate per kilowatt hour, regardless of the time of day the electricity is consumed. Flat rates are based on an average of the hourly fluctuations over time, meaning that the variation in hourly electricity prices is hidden from residential customers. With no exposure to time-based cost variation, residential customers have no incentive to conserve electricity when wholesale electricity costs are high, which contributes to the problem of peak demand growth and the rate increases required to accommodate it.

Utilities respond to peak demand growth by building more generation, transmission, and distribution capacity than would otherwise be required. One rule of thumb some use is that 10% of system costs are created by the demand in 1% of the hours in a year (87 hours). There can be no denying that unmanaged demand raises utility costs and electricity prices for all customers, and that time-varying rates can help reduce demand and lower prices in the long run. Time-varying rates can also be expected to help manage anticipated growth in EVs in a cost-effective manner.

Smart meters enable time-varying rates through their ability to record the timing (not just the volume) of electricity consumption. However, that is not the end of the story. For smart meters to be effective in managing demand, large numbers of customers must participate in time-varying rates. Though the Edison Foundation estimates 70 million smart meters have been installed in the US,[18] by the end of 2016 only 6 million of these customers were billed on a time-varying rate.[19]

Research indicates that time-varying rates represent the single largest potential economic benefit available from smart meters in most utilities' situations.[20] Clearly, installing expensive smart meters for 100% of customers when only 9% avail themselves of the capability is an unsustainable business proposition. It is the authors' informed opinion that no smart meter deployment should be approved without strong stakeholder and utility commitment to high participation in time-varying rates.

Prepayment. Like time-varying rates, prepayment is controversial. With time-varying rates, consumer advocates believe low-income customers lack the air conditioning optionality available to other customers to secure benefits from such rates. With prepayment, consumer advocates believe a lower class of service, without the credit option afforded to customers on traditional post payment, discriminates against low-income customers. Excellent resources exist to guide regulators on these issues, including a position paper on time-varying rates from the National Association of State Utility Consumer Advocates (NASUCA),[21] and a position paper on prepayment from the National Consumer Law Center (NCLC).[22] But assuming legitimate low-income issues are addressed, there is no question that customers who prepay use less electricity.

With prepayment, customers are generally provided with an in-home display or smart phone application indicating the balance available on their pre-paid account at all times. Not surprisingly, customers who pay up-front want to make their credit balances last as long as possible before having to replenish their accounts. Continuous, convenient feedback, combined with customer interest in delaying account replenishment, are thought to be responsible for the 11% reduction in electricity usage documented by prepayment customers in research.[23]

Ongoing Access to Customer Usage Data by Third Parties (When Authorized). Much is made of smart meter usage data availability. The theory is that customers will download this data, better understand their usage, and conserve energy. However, only a tiny fraction of customers will ever examine their smart meter data, and no controlled study confirms conservation benefits from usage data availability. The key is to translate data into actionable information through a convenient means, such as a smart phone app.[24]

Of course, no application developer or energy management service provider would be able to customize authorization processes and data interfaces for hundreds of US utilities on a case-by-case basis; a standard available for use with all utilities is needed. The non-profit Green Button organization has developed just such a standard, called Connect My Data, which specifies protocols for both customer authorization and usage data interface processes. Though a utility incurs some compliance costs, they are a tiny fraction of the cost of a large smart meter installation.

Some experts go even further, and believe that smart meter communications networks should be expressly designed to accommodate continuous access to smart meter data, by customers or their authorized agents, in near real time. Smart meter communications network design is yet another highly consequential grid modernization consideration which would benefit from stakeholder understanding and engagement, and is discussed in more detail later.

DISTRIBUTION GRID AND BUSINESS PERFORMANCE METRICS

Given all the variation in grid modernization results described in this section, and given the common deficiencies in utility grid modernization plans cited, it is obvious that no grid modernization plan should be approved without results measurement. It is certainly reasonable that if customers are being asked to pay hundreds of millions of dollars for grid modernization (or, in Virginia's case, to have hundreds of millions of dollars in excess earnings refunds withheld), that they be told in no uncertain terms the objectively-measured performance improvements they can expect in return.

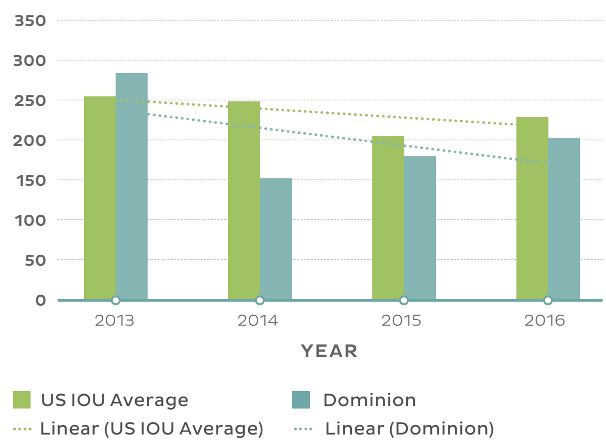
Performance expectations should be set during grid modernization planning. Stakeholders deserve to know, for instance, the size of reliability improvements, measured in minutes per year; DER generation hosting capacity increases, measured in kilowatts; voltage reductions, measured as average annual voltage by circuit; demand response from time-varying rates, measured in kilowatts; time-varying rate participation, as a percentage of customers; or operational savings, measured in dollars or dollars per average bill, which can be expected from large investments. Performance targets should be quantifiable, not subjective; include achievement dates; and be based on outcomes, not processes.

Baselining is a critically important part of performance measurement. Every performance metric established during grid planning should be measured prior to grid modernization deployment, both as a reference point for setting targets but also to confirm metric feasibility and to refine measurement definitions and calculation methods.

Another important aspect of performance target-setting is benchmarking against peer utilities, as any one utility's historical performance can lead to poor target setting. For example, as reported on Energy Information Administration Form 861, Dominion's post-storm restoration results (as measured by SAIDI *with* major event days) are not only better than the US utility average, Dominion storm restoration is improving at a faster rate than the average US utility.[25] Benchmarking can therefore be used not just to evaluate grid modernization results, but to help prioritize grid modernization investments, capabilities, and performance metrics. Concerns that Dominion's reliability performance is putting Virginia at a competitive disadvantage relative to other states may be misplaced. (Chart courtesy of the Utility Evaluator.)

SAIDI WITH MAJOR EVENT DAYS

Data sources: EIA Form 861



EVALUATING DOMINION'S GRID TRANSFORMATION PLAN

With an understanding of the contents and characteristics of a "no regrets" grid modernization plan, stakeholders can better evaluate Dominion's Grid Transformation Plan. To review, foundational software should generally come first, with geographic expansions through associated investments in grid hardware pursued only as need is demonstrated through a transparent grid planning process. Smart meters can serve critical roles in a modern grid, and can be installed for no net cost to customers if care is taken to maximize available benefits.

In this section the authors offer their informed perspectives on what Dominion's Plan gets right, what the Plan is missing, and questionable Plan elements requiring further investigation. The suggestions presented were identified after a cursory review of Dominion's Plan. An in-depth analysis, including an extended discovery process conducted by experts in grid asset management, capacity planning, operations, metering, and communications networking, is highly recommended. The suggestions are not intended to be exhaustive collectively, or complete individually, but are directional and illustrative in nature.

WHAT DOMINION'S GRID TRANSFORMATION PLAN GETS RIGHT

While this paper is generally critical of Dominion's Grid Transformation Plan, there are aspects of the Plan which are reasonably required to improve reliability and resilience, and to increase the capacity of the grid to host high levels of DER generation.

Advanced Distribution Management Software (ADMS). Dominion's Plan proposes to install Advanced Distribution Management Software to help grid operators model and execute grid configuration changes. Today, grid operators have almost no visibility to what is happening on the grid below the substation level. Electricity is placed onto distribution circuits at the substation, and customers pull energy from the circuits. Today, grid configuration changes are relatively easy to plan and execute, as grid operators can rely on this state of affairs.

As described earlier, high levels of DER generation complicate grid configuration change planning and execution. ADMS applies complex math to data secured from sensors placed on the grid to help a grid operator understand the impacts of grid configuration options he or she may be considering, taking into account the impact of DER. ADMS helps grid operators make sound reconfiguration choices quickly, reducing the likelihood of errors which could cause reconfiguration-induced outages and/or equipment damage.

ADMS also helps grid operators execute grid configuration changes. From the ADMS, grid operators can often remotely control switches, remotely re-set the parameters for operation of circuit breakers and other equipment, and take other actions required to reliably and safely execute the preferred grid configuration chosen by the grid operator. These capabilities help ensure that high levels of DER generation can be accommodated with no increase in reconfiguration risk. In addition, through the remote execution capabilities of ADMS, grid reliability and resilience[26] are improved, at least to the extent software capabilities have been extended to the grid via equipment upgrades.

Distributed Energy Resource Management Software (DERMS). Distributed Energy Resource Management Systems help grid operators keep track of DER generation in near-real time, by circuit or section thereof. DERMS are generally integrated with ADMS, providing data inputs for ADMS to analyze and incorporate into grid reconfiguration analyses. DERMS can also be used to control DER in emergency situations (if DER inverters are securely connected to DERMS via a communications network).[27] Finally, DERMS can serve a historical data analysis and reporting function. Historical data analysis and reporting functions can be useful for settling financial transactions, estimating locational value, and predicting future growth rates of DER.

WHAT IS MISSING FROM DOMINION'S GRID TRANSFORMATION PLAN

Integrated Volt-VAr Optimization. Though it is frequently deployed as part of the Advanced Distribution Management System software described above, Integrated Volt-Var Optimization (IVVO) merits special mention due to its exceptionally strong benefit-cost ratio. As described above, IVVO improves grid energy efficiency. It operates on a fully continuous basis in the background, controlling grid devices such as voltage regulators, load tap changers, static VAr compensators, and capacitor banks, in order to optimize voltage (the "Volt" in IVVO) and power factor (the "VAr" in IVVO) all along a distribution circuit. By doing so, the energy efficiency of the grid is improved.

Most utilities operate grid circuits in the range of 118 to 124 volts on average throughout a year. Research indicates that IVVO can reduce this amount by 3-5%, which translates to an electricity usage reduction of approximately 1.5-4%.[28] A "back of the napkin" calculation can be used to develop a rough estimate of IVVO benefits to the Virginia economy in dollars. Assuming the lowest benefit in this range (1.5%), and that IVVO software capabilities are expanded to 20% of Dominion's circuits through equipment upgrades, and that the top 20% of Dominion's circuits distribute 40%

of electricity sold, and that fuel costs represent 25% of sales revenue, this single capability would produce a minimum of $11.3 million in economic benefits annually to Virginia businesses, government and non-profit agencies, and consumers.[29]

Unfortunately, Dominion's Plan makes no mention of Integrated Volt-VAr Optimization. While this is understandable, as IVVO reduces sales volumes and profits, it is not acceptable. In fact, when Dominion does install IVVO, the throughput incentive demands that stakeholders secure ongoing average voltage by circuit reports to ensure performance. (Some states allow IVVO to qualify as an energy efficiency program; the performance measurement approach proposed by Ameren Illinois is a good example to consider.)[30] The absence of IVVO in Dominion's Plan is all the more conspicuous as an unregulated sister company, Dominion Voltage, was formed specifically to develop and sell IVVO solutions to utilities.[31]

A Transparent Grid Planning Process Featuring Risk-Informed Grid Project Prioritization and Selection Software. As described above, many utilities use risk-informed grid project decision support software when planning grid investments and capital budgets. This software allows grid planners and stakeholders to assign a risk reduction value (in terms of reliability risk, to include DER and EV accommodation, and safety risk) to every grid project which might be part of an overall grid development plan. Project evaluation should include both traditional grid projects and physical improvements to grid circuits and equipment upgrades for grid modernization, and enable project value to be evaluated in the context of project cost. The software ranks proposed projects in order of greatest value per dollar to least value per dollar.

Armed with information on both the cost and value of each proposed project, stakeholders should have input on where to "draw the line" among the ranked list of proposed projects. Projects above the line "make the cut" and are funded; projects below the line are temporarily dropped from consideration. Dropped projects are re-considered in a future grid plan, when they will be subjected to the same prioritization and selection process relative to other projects and priorities which will arise over time. Use of such a process is essential to extending software capabilities to the grid to an appropriate extent, rather than to an excessive extent. Appropriate expansion reduces the cost of grid modernization and maximizes customer bang for the buck.

A Strong Commitment to High Levels of Participation in Time-Varying Rates. As described earlier, a strong commitment to high levels of participation in time-varying rates is generally required if smart meters are to deliver customer benefits in excess of customer costs. The Dominion Plan contains no mention of time-varying rates, and its smart meter benefit-cost analysis includes no associated economic benefits such as demand reductions or electricity conservation.

A Prepayment Program. As described earlier, a properly designed and implemented prepayment program enabled by smart meters can conserve electricity and save customers money. No prepayment program is mentioned in the Dominion Plan, and its smart meter benefit-cost analysis includes no associated economic benefits from electricity conservation.

A Performance Measurement Program. As described earlier, high variation in grid modernization results from utility to utility, as well as deficiencies in Dominion's benefit-cost analysis (described in more detail below), make a comprehensive performance metric program a necessity for every grid modernization plan. A suite of performance metrics — including, for each metric, definitions/calculations; baselines of existing performance; objective and quantitative targets; and timeframes for achievement — should be part of Dominion's Plan. A process for ongoing target setting and performance monitoring should be part of a long-term program for continuous distribution grid and business improvement. Dominion's Plan includes no performance measurement program.

Compliance with the Connect My Data Standard (Smart Meters). As described earlier, customers need a way for usage data to be translated into actionable information if conservation benefits from smart meters are to be maximized. As consumers exhibit differences in "willingness to pay" and desired feature sets, open markets (i.e., third party service providers competing against each other) are likely the best way to increase consumer choice and reduce consumer prices for energy management and related services. (On a related note, care must be taken to ensure smart meter and communications technology choices do not serve to expand Dominion's electric distribution monopoly into markets which are not natural monopolies, or allow Dominion to take advantage of its dominant market position). Compliance with the Connect My Data standard can help accomplish these objectives and increase conservation, but are missing from Dominion's Plan and smart meter benefit-cost analysis.

CONCERNS ABOUT DOMINION'S BENEFIT-COST ANALYSIS

In addition to concerns about missing benefits, experience with grid modernization deployments in other states indicates that Virginians should be concerned about Dominion's ability to deliver the customer benefits projected for the costs estimated.

How will Dominion translate operating benefits into rate reductions in a timely manner? As described earlier, a rate case is required to translate operating benefits, such as reductions in labor or electricity theft, into rate reductions for customers. If Dominion is compensated for grid modernization costs through a rider, or through the excessive earnings stockpile, Dominion might not need to conduct a rate case which would result in such rate reductions for many years. Until such a rate case/rate reduction, operating benefits accrue to shareholders, not customers.

Some type of mechanism is needed to ensure utility operating benefits get translated into customer rate reductions in a timely manner. In Ohio[32] and Oklahoma,[33] regulators ordered that operating benefits projected by year be automatically deducted from revenue requirements in grid modernization cost recovery rider calculations in respective years. If the utility projected operating benefits in year 5 to be $12 million, $12 million was deducted from the grid modernization rider the utility was authorized to charge customers in year 5. These orders enabled operating benefits to flow to customers until a rate case could be conducted in which the test year reflected fully realized operating benefits. This approach is not available if Dominion elects to recover grid modernization costs through the excessive earnings stockpile instead of a rider.

What does Dominion's smart meter benefit-cost analysis look like with a 15-Year period? As described earlier, many utilities use a 20-year period in benefit-cost analyses despite the fact that smart meters are only expected to last about 15 years. This artificially inflates benefits relative to costs in a benefit-cost analysis. Dominion uses a 20-year period in the benefit-cost analyses provided in its Grid Transformation Plan. Stakeholders should ask Dominion to prepare 15-year and 18-year benefit-cost analyses for smart meters. In addition, any and all benefit-cost analyses should be calculated using Net Present Value.

What do the benefit-cost analyses Dominion provided look like in terms of net present value? As described earlier, the use of nominal (vs. net present value) benefit estimates artificially increases benefit values, as nominal benefits which stretch far into the future do not take inflation into account. Dominion's benefit-cost analyses appear to use nominal benefits, not net present value benefits. Dominion should calculate benefit-cost analyses using the net present value approach to account for the fact that an economic benefit received 15 years from now does not have the same value to customers as a benefit received this year. In addition, any and all benefit-cost analyses, whether nominal or net present value, should include the carrying costs customers will be asked to pay on grid modernization assets.

Will Dominion guarantee economic and reliability benefits to the levels/in the timeframes projected? If Dominion's Plan is approved as it stands now, all risk of benefit shortfalls falls on customers. To the extent projected benefits are not achieved, or to the extent operating benefits are not shared with customers via timely rate decreases, or to the extent benefits take longer to deliver than expected, the cost to customers of grid modernization will rise.

It does not seem equitable that Dominion shareholders receive profits on grid modernization investments regardless of the level benefits Dominion actually delivers. Stakeholders may wish to pursue some sort of risk-sharing arrangement in which Dominion has "skin in the game" regarding the achievement of projected benefits.

What carrying costs will customers have to pay over the life of grid modernization assets? As described above, customers will be asked to pay carrying costs, including profits, taxes on profits, interest expense, and property taxes, on all grid modernization assets. In the authors' experience, carrying costs can amount to 20% or more of total grid modernization costs to customers. Yet Dominion does not appear to have included carrying costs in any benefit-cost analyses provided in its Grid Transformation Plan. Stakeholders should ask Dominion to estimate carrying costs assuming existing authorized profit percentages and current rates for interest, income taxes, and property taxes, and to update benefit-cost analyses accordingly.

What is the book value of assets which will be retired from service prematurely? As described above, if Dominion is planning on recovering the cost of assets removed from service to make way for grid modernization, it should include such costs in benefit-cost analyses. It does not appear that the cost of assets which will be retired from service prematurely, and which Dominion probably expects to continue to recover from customers, are included in any of the cost-benefit analyses provided in Dominion's Plan. Stakeholders should confirm Dominion's plans for cost recovery on assets retired prematurely. If Dominion will continue to recover the costs of such assets from customers, those costs, including the associated carrying costs described immediately above, should be included in benefit-cost analyses.

Stakeholders should ask Dominion to identify the assets which would be prematurely retired as part of its Plan, quantify the book value of those assets to be recovered from customers, estimate the carrying costs associated with such recovery, and update benefit-cost analyses accordingly.

Will Dominion cover cost overruns? If Dominion's Plan is approved as it stands now, all risk for cost overruns will fall on customers. Though the SCC can always deny recovery from customers of cost overruns based on imprudence or gross negligence, these are notoriously difficult to prove. It does not seem equitable that Dominion bears no risk for grid modernization cost overruns. Stakeholders may wish to pursue a risk-sharing arrangement in which Dominion bears some responsibility for cost overruns.

Cost overrun responsibility assignments must work hand in hand with performance measurement. It is conceivable that a utility facing cost overruns would cut back on grid modernization capabilities or geography to avoid taking a hit to earnings. The presence of performance measures should discourage such cut backs, or at least help ensure that any such cut backs are identified (when performance targets are missed).

Is there a prioritized list of physical grid improvement projects? Because customers are paying, one way or another, for grid modernization, their representatives should have a say in its nature and extent. If Dominion used risk-informed grid project prioritization and selection decision support software, a list of physical grid improvement projects, ranked by value (benefits per dollar), should exist. If such software was not used, stakeholders should demand Dominion subject the components of its Plan to such an analysis and publish all assumptions, analyses, calculations, and results.

How will Dominion recover grid modernization costs? The GTSA provides Dominion with three options as to how it can recover grid modernization costs: 1) through the use of the excessive earnings stockpile; 2) through the use of a rider; or 3) in base rates (through the use of a rate case). The fact that Dominion does not make any reference to cost recovery methods in its Plan indicates that Dominion is keeping its recovery options open. As described throughout this paper, different recovery methods offer different pros and cons to customers and shareholders, and such pros and cons may shift as the SCC proceeding to consider Dominion's Plan develops. Stakeholders should remain engaged on this issue, perhaps to the extent of specifying a certain cost recovery method as the Plan evolves throughout the SCC proceeding.

RELIABILITY AND RESILIENCE INQUIRIES

Dominion's Plan proposes to spend an enormous amount of capital to "harden" the grid in the name of reliability and resilience. The Plan includes $232 million in capital for grid hardening in just the first 3 years (Phase 1), and a whopping $1.5 billion over 10 years. Dominion expects $232 million in grid hardening capital — about $100 per Dominion customer — to deliver an annual SAIDI improvement of 1 to 4 minutes. The $1.3 billion balance is likely to deliver even less SAIDI improvement per dollar as Phase 1, as Dominion says Phase 1 "will identify and prioritize the work that will achieve the greatest benefit." This implies that future phases will deliver less benefit than Phase 1.

Given the choice of a $100 excess earnings refund or an annual reliability improvement of 1 to 4 minutes, it is likely that 100% of customers would take the refund. With this perspective in mind, stakeholders are encouraged to aggressively pursue inquiries regarding reliability and resilience. A few suggestions are provided below.

What are the details behind smart meter reliability economic benefit calculations? Stakeholders should examine Dominion's calculations for the economic benefit from reliability improvement included in the smart meter benefit-cost analysis. In the authors' experience, the reliability benefits from smart meters are very small, particularly in relation to the reliability benefits available from grid configuration flexibility (what Dominion calls FLISR, or fault location, isolation, and service restoration, in its Plan).

In examining the smart meter reliability benefit calculations, stakeholders should seek answers to the following questions:

- What SAIDI improvements can be attributed to smart meters?

- What assumptions were used to translate SAIDI improvements into economic benefit?
- Are those assumptions reasonable? Is it possible Dominion has over-estimated the economic benefit from smart meter-related reliability improvements?
- What is the breakdown of reliability-related economic benefits between customer classes?

What are the reliability and resilience benefits of each grid hardening component? Dominion's $1.5 billion grid hardening plan includes 3 distinct components: 1) introducing more stringent line and substation transformer loading standards and replacing functional equipment; 2) increasing construction of tie lines (grid configuration flexibility); and 3) undergrounding functional overhead lines. In the authors' experience, as described earlier, only grid configuration flexibility offers appreciable improvement in reliability and resilience. Stakeholders may wish to secure more information on the individual reliability and resilience benefits of each of these investments, and ask Dominion for any research available to support claims of reliability and resilience improvements from these actions. With a 1-4 minute SAIDI improvement and $232 million price tag, the grid hardening value proposition is extremely suspect.

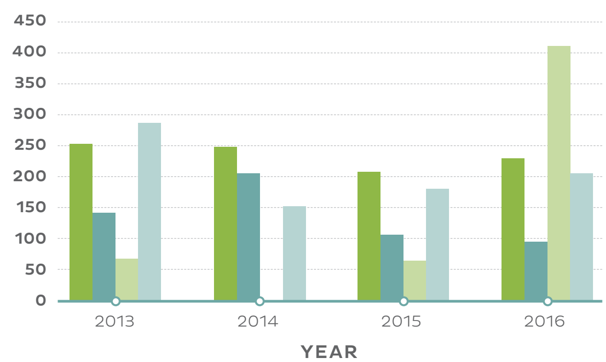
Furthermore, these proposed grid hardening investments are not transformational in any way; they are nothing more than traditional distribution equipment on steroids. Undergrounding offers little if any reliability or resilience benefit, as above-ground issues are replaced by flooding and excavation concerns. Increasing circuit and transformer loading standards for no apparent reason, and then replacing equipment which no longer meets the new standards, is self-serving at best (a result of Dominion's capital bias). Operating lines at 100% of rated capacity, and operating substation transformers at normal overload limits, is standard practice at all utilities worldwide. This is validated by the fact that Dominion's reliability and resilience performance, using its existing standards and equipment, is in line with US utility averages (see charts below).

Stakeholders should demand that the grid-wide initiatives proposed be broken down into specific locational projects, and then subjected to the risk-informed grid project prioritization process described earlier. It is highly likely that almost all of the location-specific applications of undergrounding, and rebuilds to more stringent standards, would fall "below the line". That is, the projects would not be funded due to insufficient value delivered relative to project cost.

Is Dominion willing to commit to dramatically better reliability performance? In its Plan, Dominion cites the grid hardening experiences of ComEd and FP&L. Consider the following chart comparing the three utilities' SAIDI performance, both with and without major event days (representing storm response and clear day reliability, respectively) over the last few years to the US utility average:

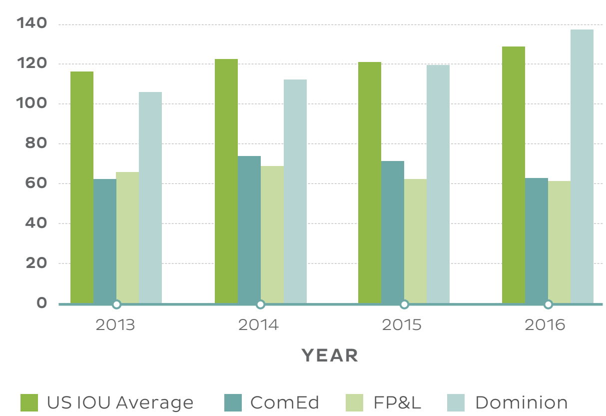
SAIDI WITH MAJOR EVENT DAYS

Data sources: EIA Form 861



SAIDI WITHOUT MAJOR EVENT DAYS

Data sources: EIA Form 861



Regarding FP&L resilience, the impact of Hurricane Irma is clear in 2016, and FP&L did not report a SAIDI with major event days statistic in 2014. Still, the charts indicate that ComEd's and FP&L's storm response and clear day reliability performance are dramatically better than Dominion's, not just slightly better. This stands in stark contrast to Dominion's estimate that $232 million in grid hardening will deliver just 1-4 minutes improvement in SAIDI. If Dominion wants regulators to approve $1.5 billion in grid hardening capital, using ComEd and FP&L storm response and clear day reliability performance as justification, Dominion should commit to ComEd and FP&L-type storm response and clear day reliability performance levels, not just 1-4 minutes of improvement for each $232 million in grid hardening capital spent. (Charts courtesy of the Utility Evaluator.)

COMMUNICATIONS NETWORK INQUIRIES

Clearly, communications between Dominion grid and metering operations departments and grid equipment and smart meters are required. The fact that Dominion has considered this need in its Plan is good. Unfortunately, communications performance specifications, a description of alternatives available to meet them, objective selection criteria, and a rigorous effort to compare alternatives are all absent from the Plan.

Dominion proposes to spend $442 million in capital to build out its grid communications network over 10 years. This does not appear to include the smart meter communications network, which will likely cost tens of millions of dollars more, nor does it include the cost to operate and maintain the network over time. Before spending half a billion dollars on a proprietary, dedicated communications network, serious stakeholder engagement and expert inquiry are recommended.

Communication network decisions are among the most foundational made in grid modernization planning, as communication network capabilities can serve to limit or enhance the capabilities of other grid investments. Key issues to be resolved include:

- Build (utility owns) or Buy (utility buys services from public network providers)?
- Exposure to obsolescence (and associated interoperability/upgradability issues)
- Data latency and capacity (bandwidth, and associated increase options)
- Resilience to power loss (backed up by batteries?)
- Cybersecurity
- Customer and (authorized) third-party data access (smart meters)
- Accountability (a communications network presents an entirely new network which must be operated and managed in addition to the electric distribution grid)

This is a time of rapid advances in the wireless data communications industry. Recent developments include low-cost public networks (such as Verizon's Cat M1, designed specifically for low power, low bandwidth, non-mobile devices like smart meters and grid equipment) and private 4G LTE cellular networks. Developments anticipated in just the next year or two include the Internet of Things and fifth-generation (5G) cellular networks. Communications network design and operation are not core utility capabilities; "leaving it to the experts" may deliver the best results for customers in the long term.

The Rhode Island Public Utilities Commission is a leader on this issue, and its Power Sector Transformation proceeding (Docket 4780) is worthy of Virginia consideration. The Rhode Island PUC recently ordered its utility (Narragansett Electric, owned by National Grid) to deliver smart meter and grid modernization plans with multiple communications options for comparison.[34] It is possible, if not likely, that the timing for Dominion to spend half a billion dollars to build its own communications networks is less than ideal.

REVIEW AND CONCLUSIONS

This paper has described the benefits and risks of grid modernization in Virginia and the contents and characteristics of a "no regrets' grid modernization plan. It has also presented multiple opportunities to improve Dominion's Grid Transformation Plan, and described areas of inquiry into some questionable components of the Plan. Conclusions are offered for the reader's consideration.

WE KNOW WHAT SOUND GRID MODERNIZATION LOOKS LIKE

Most states' utilities, regulators, and stakeholders are fiercely independent, believe their situations to be unique, and are keen to forge their own grid modernization path. There is no doubt that laws and rules vary by state, that goals vary by state, and that each utility's situation presents individual characteristics and variation in current circumstances which must be taken into account in grid modernization. However, the laws of physics and economics, and the challenges electric distribution grids and businesses are likely to face in the future, are the same everywhere.

As the body of grid modernization knowledge evolves, legislators, regulators, and stakeholders are strongly encouraged to take advantage of experiences in other states. No matter the circumstance or challenge, other states have probably already examined and dealt with it in some way, with varying degrees of success. Learning about other states' experiences does not obligate Virginia regulators and stakeholders to copy their solutions, but it can help avoid mistakes and extend successes.

DUE TO PERFORMANCE VARIATION AND CONTRARIAN INCENTIVES, SIGNIFICANT STAKEHOLDER ENGAGEMENT AND REGULATORY OVERSIGHT IS REQUIRED

A sound grid modernization plan involves more than just technologies, capabilities, and investments. A sound grid modernization plan includes strong stakeholder engagement and regulatory oversight throughout the planning, implementation, and operational stages of grid development. To maximize return on investment for customers and the environment, planning processes must be designed to identify the most critical capabilities; the most cost-effective ways to implement them; the most appropriate geographic extent for them; and methods to maximize available benefits for customers, from conservation to performance measurement.

To recognize the importance of good governance is to appreciate the need for long-term oversight and ongoing participation in grid modernization by regulators and stakeholders. Grid modernization is not solely the responsibility of utilities, and regulators and stakeholders must be prepared to contribute their own resources and take on new roles and responsibilities. Many of these new roles and responsibilities are the direct result of managing the conflict between shareholder and customer interest inherent in the current regulatory construct, exacerbated by the grid modernization drivers described in the Introduction. At some point, the costs of the current regulatory construct may exceed the benefits of the current regulatory construct.

IN THE LONG RUN, FUNDAMENTAL REGULATORY REFORM MAY BE NECESSARY

Capital bias and the throughput incentive have driven utility investment and operating decisions for the better part of a century. Grid modernization governance requirements are driven largely by the need to manage the conflicts between shareholder and customer interests. Eliminating the conflicts eliminates some governance requirements (though not performance measurement, which is recommended in any event). As regulators and stakeholders have neither the technical expertise nor resources required to evaluate utilities technical arguments for grid investments, a regulatory model which eliminates capital bias may be warranted. As customers become more interested in conservation and self-generation, the throughput incentive must also be addressed. As industry conditions change, monopoly compensation models likely need to change too.

This whitepaper presents many new grid modernization issues the Virginia SCC and legislators had not previously considered. The issues are complicated, the solutions are controversial, and the workload and negotiations required to address them will be formidable. It may be tempting to minimize the issues, or to give up on grid modernization altogether, though either course of action short changes Virginia businesses, consumers, and government and non-profit agencies.

If Dominion chooses to draw down excessive earnings to pay for grid modernization, it may be even more tempting to ignore the issues presented. After all, the investments are already paid for, and will require no rate increases from customers. Stakeholders are encouraged to reject this perspective entirely. Make no mistake: excessive earnings belong to customers. Stakeholders, regulators, and legislators owe customers the best possible grid for the least possible cost, and this paper is dedicated to that outcome. Stakeholders are strongly encouraged to take the information in this paper to heart, and to act upon them in SCC Grid Transformation Plan proceedings.

GridLab hopes readers have found this paper and its perspectives valuable. For more information or for questions, please contact Taylor McNair in GridLab's primary offices in San Francisco at 415-305-3235.

ENDNOTES

1 In the context of this paper, "utility" generally refers to an investor owned utility (IOU). Most, but not all, of the issues presented in this paper apply to non-profit utilities as well.

2 "Distributed Energy Resources", or DERs, are smaller power sources that can be aggregated to provide power necessary to meet regular demand. DER can include energy storage and advanced renewable generation technologies such as photovoltaic solar panels or waste heat/biogas-fueled turbines. DER can be owned by utilities, customers, or third-parties. Many people include demand response, in which customers reduce consumption when requested to improve system utilization, in the definition of DER.

3 US Department of Energy. *US Energy and Employment Report*. January, 2017. Page 8.

4 Colorado Public Utilities Commission 11A-1001E, "SmartGridCity© Demonstration Project Evaluations Summary", Exhibit MGL-1 December 14, 2011; Public Utilities Commission of Ohio 10-2326-GE-RDR, "Smart Grid Audit and Assessment", June 30, 2011; California Division of Ratepayer Advocates, "Case Study of Smart Meter System Deployment", March, 2012.

5 2010-2016 data submitted by US electric investor-owned utilities on FERC Form 1 and EIA Form 861. Accessed via the Internet at http://www.utilityevaluator.com (available by subscription) on July 26, 2018.

6 Ibid.

7 Virginia Code, Title 56, Chapter 10, Section 585.1, Paragraph A.vi

8 Virginia Code, Title 56, Chapter 10, Section 580, Paragraph D.ii.

9 System Average Interruption Duration Index, a standardized approach to measuring reliability.

10 Energy Information Administration Form 861. Virginia Electric and Power Company SAIDI without Major Event Days = 138.2 minutes. 2016.

11 US Energy Information Administration estimate. Accessed via the Internet at https://www.eia.gov/tools/faqs/faq.php?id=105&t=3 on July 26, 2018.

12 Investor-owned utilities profit by earning a rate of return on capital investments authorized by regulators. While grid investment is something worthwhile to encourage, this regulatory provision motivates such utilities to invest more capital than might be necessary, or to invest its own capital rather than take advantage of non-capital solutions (such as third-party services). This is called "capital bias".

13 Like most corporations, Investor-owned utility profits rise when sales volumes rise, and fall when sales volumes fall. As a result, for-profit utilities are motivated to sell more electricity. This is called "the throughput incentive".

14 Hosting capacity is defined as how much DER a circuit or section can accommodate without significant upgrades.

15 Locational benefits are defined as the potential cost avoidance available from new DER generation.

16 Cooper, A. *Electric Company Smart Meter Deployments: Foundation of a Smart Grid*. Edison Foundation Institute for Electric Innovation. Page 2. October, 2016.

17 Massachusetts Department of Public Utilities 15-120, Order dated May 10, 2018; New Mexico Public Regulation Commission 15-00312-UT, Order dated April 11, 2018; Kentucky Public Service Commission 2018-00005, Order dated August 30, 2018.

18 Ibid.

19 Sum of "Residential Customers on a Dynamic Rate". 2016 data submitted by US electric utilities on EIA Form 861. Accessed at https://www.eia.gov/electricity/data/eia861/ on August 17, 2018.

20 Alvarez, P. *Smart Grid Hype & Reality: Maximizing Customer Return on Utility Investment, 2nd ED*. Page 159. Wired Group Publishing, 2018.

21 *Guidance for Utilities Commissions on Time of Use Rates: A Shared Perspective from Consumer and Clean Energy Advocates*. July 15, 2017.

22 Howatt J and McLaughlin J. *Rethinking Prepaid Utility Service*. National Consumer Law Center. June, 2012

23 Ozog, M. *The Effect of Prepayment on Energy Use*. Integral Analytics. Page 2. March, 2013.

24 Two third parties (Chai Energy and Ohm Connect) have already developed such apps. These apps require secure, ongoing access to the usage data of customers who have authorized the smart phone app to have such access.

25 2013-2016 SAIDI without major event days data submitted by US electric investor-owned utilities on EIA Form 861. Accessed via the Internet at http://www.utilityevaluator.com (available by subscription) on August 17, 2018.

26 Resilience is loosely defined as reconfigurations required by outages or widespread storm damage.

27 It is highly recommended that a utility's DER interconnection requirements specify compliance with the relevant IEEE standards, including 1547 (DER inverters) and 2030.5 (communications) as amended over time.

28 A variety of research (Pacific Northwest National Lab 19596, *Evaluation of Conservation Voltage Reduction on a National Level*, July 2010; Northwest Energy Efficiency Alliance, *Distribution Efficiency Initiative Final Report*; and others) supports the 3-5% average delivery voltage reduction estimate. A significant variable is the conservation voltage reduction factor, which reflects the fact that a reduction in voltage only reduces the electricity consumed by resistive loads, not all loads. (Resistive loads are only a portion of the loads which use electricity, the balance consisting of reactive loads.) Research supports conservation reduction factors of 50-80%, resulting in the estimated energy conservation impact estimate of 1.5-4.0% (50-80% of a 3-5% reduction in average delivery voltage).

29 According to Dominion's 2017 10k report filed with the SEC (page 76), Virginia Electric and Power Company revenues were $7.556 billion, and fuel costs were $1.909 billion (25% of revenues). Thus, the calculation of savings from IVVO is $7.556 billion x 40% (revenues on 20% of circuits on which IVVO is hypothetically extimated) x 1.5% (conservation estimate) x 25% (portion of revenues representing reductions in fuel costs), or $11.3 million annually.

30 *Ameren Illinois Voltage Optimization Plan*. Pages 27-29. January 25, 2018.

31 Visit www.dvigridsolutions.com for more information.

32 Ohio Public Utilities Commission 10-2326-GE-RDR. Approved Settlement Agreement dated February 24th, 2012. Pages 5-10.

33 Oklahoma Corporations Commission 2010-00029, Order 576595. Approved Settlement Agreement dated May 27, 2010. Page 3, item F.

34 Rhode Island Public Utilities Commission dockets 4770 and 4780. Amended Settlement Agreement dated August 10, 2018. Pages 52-53.

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