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GETTING THE MOST OUT OF GRID MODERNIZATION

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The risk vs. reward calculus looks different in a regulated utility context than it does in a competitive market. Keeping these differences in mind, these program design ideas illuminate options for sharing the value of grid modernization investments fairly between utility shareholders and utility customers.

As states consider new utility investments in modernizing the grid, state regulators need some way to ensure that utilities maximize the potential benefits of grid modernization fairly and in a timely fashion.

This white paper provides program design considerations and metrics that can guide utility investment and increase the chances that customers get the most out of grid modernization efforts.

Five key steps[1] should guide a successful grid modernization program:

1. Start by assessing the costs and benefits of distributed resources and a modern grid in the context of existing and planned generation and transmission.
2. Clearly define policy goals based on that assessment; focus on desired outcomes.
3. Tie metrics as closely to those goals and outcomes as is feasible. Ensure that they can be quantified and independently verified using reasonably available data, and avoid reliance on counterfactuals[2] when measuring performance.
4. Set realistic targets that balance costs and benefits and incorporate stakeholder input.
5. Consider tying utility revenue to performance against these targets.

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[1] Steps adapted from Aggarwal, Sonia & Eddie Burgess, "New Regulatory Models," *America's Power Plan* and *The Utility of the Future Center*, March 2014; and from Woolf, Tim & Melissa Whited, "Utility Performance Incentive Mechanisms: A Handbook for Regulators," *Synapse Energy Economics*, March 2015.

[2] Orvis, Robbie, "Avoiding Counterfactuals in Performance Incentive Mechanisms: California as a Case Study," *America's Power Plan*, April 2016. http://americaspowerplan.com/wp-content/uploads/2016/04/AvoidingCounterfactuals-white-paper.pdf

The following sections walk through these steps in order.

STEP 1. CONDUCT AN INTEGRATED ASSESSMENT OF THE DISTRIBUTION AND TRANSMISSION SYSTEMS

Good practice for grid modernization programs starts with "integrated distribution planning" (IDP), a practice in which demand-side and distribution-level investments are considered in conjunction with bulk-system resources to achieve an optimized, integrated system.[3] This includes understanding the potential contribution from distributed energy resources, including a general assessment (and ideally a locational assessment) of a cost-effective portfolio of resources.[4,5,6] Without a clear assessment of how distribution-level resources can provide value to the grid as a whole, utilities will struggle to unlock the full potential of grid modernization to provide environmental, reliability, and savings benefits.

At the same time, IDP can produce the data that regulators and stakeholders will need to measure and set rational targets for grid modernization performance. Smart customer-facing rate design, DER procurement, and technology deployment can then be used to improve overall environmental and economic performance.

STEP 2. DEFINE THE GOALS OF A GRID MODERNIZATION PROGRAM

Different regions may identify different goals for grid modernization programs; the point is that time should be spent early in the program to ensure that stakeholders are on the same page with the full set of goals. This paper focuses on the three goals we consider most important: Investment to modernize the grid should yield: (1) affordability, (2) resilience, and (3) environmental performance.

STEP 3. CHOOSE METRICS FOR EACH GOAL

Focusing on broader outcome-oriented metrics[7] for the full portfolio of grid modernization investments allows the utility more flexibility to find the least-cost approach to deliver outcomes and should reduce the administrative burden on regulators reviewing utility investments. For example, the utility has choices about whether to focus on Volt-VAR optimization programs, improve integrated system planning, improve customer response through automation or

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[3] For a definition of IDP, see Electric Power Research Institute, *The Integrated Grid*, accessed January 26, 2016, http://integratedgrid.com/; SolarCity, "Integrated Distribution Planning," 2015. http://www.solarcity.com/sites/default/files/SolarCity%20White%20Paper%20-%20Integrated%20Distribution%20Planning_final.pdf. For examples and best practices, see Coleman, Amy et al., "Planning the Distributed Energy Future: Emerging Electric Utility Distribution Planning Practices for Distributed Energy Resources", Smart Electric Power Alliance, 2016. http://www.solarelectricpower.org/media/438405/Proactive-DER-Planning_SEPA_BV.pdf.

[4] For more detail, see "More Than Smart," *Greentech Leadership Group*, August 2014.

[5] This is the ultimate goal of California's Distributed Resource Planning proceeding: http://www.cpuc.ca.gov/General.aspx?id=5071.

[6] Bode, Josh et al., "Addressing the Locational Valuation Challenge for Distributed Energy Resources," Solar Electric Power Alliance in partnership with Nexant, September 2016.

enrollment in time-of-use rates, or undertake any number of other measures. Over the course of a grid modernization investment program, the utility is likely to learn which of these avenues or combination thereof is most effective. And as long as outcomes are being achieved for each goal, regulators and customers may not need to perform line-by-line review of the utility's individual investments and activities.

At the same time, policymakers should consider how much control the utility has over performance for each metric. The degree of control most often lies on a spectrum. For example, customer behavior that is outside the utility's control can impact overall bills. However, there are actions the utilities can take to shape customer behavior to some degree. The utility should be encouraged to weigh those kinds of actions against more traditional investments.

The following sections provide sample metrics for each of the three goals: (1) affordability, (2) resilience, and (3) environmental performance.

Measuring affordability

Overall program cost or bill savings per customer ($ or %) are the most direct and outcome-oriented affordability metrics. However, it does not pay to consider only these metrics in isolation as representative of affordability. Program costs should be considered in the context of the value grid modernization is delivering to customers. The metrics described in the rest of this section focus on outcomes that signify a good *value* program, as opposed to focusing strictly on least-cost.

Peak demand reduction or *system load factor*[8] represent two similar approaches to determine the value of grid modernization investments, since a modern grid should be managed dynamically and thus should strive to become less "peaky." Reducing peak or increasing system load factor saves money by taking better advantage of existing infrastructure (reducing the need for additional investment) and by avoiding purchasing energy at the most expensive times. A 2009 Federal Energy Regulatory Commission report provided demand response potentials for each state, ranging from 5-23 percent of peak demand.[9] These rough estimates—plus one or two carefully chosen normalization factors—could form the basis for a peak demand reduction target until analysis can be conducted to determine utility-specific achievable potential and assess the economic benefits of peak reduction. If a state or region decides to conduct such a study, it should incorporate information from the utility, but rely primarily on independent analysis. An outcome-oriented metric such as a *reduction in peak from a start year* (kilowatts: perhaps system average, perhaps per feeder) can focus investments and activities on minimizing

[8] System load factor refers to the average load divided by the peak load in a specified time period.

[9] See Federal Energy Regulatory Commission, "A National Assessment of Demand Response Potential." June 2009, at Appendix A.

overall costs.[10] Absolute peak reductions could be normalized to account for economic growth or weather anomalies.

Additional metrics may also be worth tracking in the category of affordability, particularly where regulators feel the utility has fallen short or could use the help of third parties. For example, the following indicators may be useful to consider: enrollment in an opt-in time-of-use rate (# or % of customers); enrollment in a demand response program (# or % of customers); customer and third-party information access (# of customers accessing online information, # of times accessed per month, % of customers sharing data with third parties); and share of customers using automation technology in conjunction with time-varying rates (%).

Measuring resilience

Well-executed grid modernization efforts improve situational awareness and allow for islanding or other approaches to stop cascading outages. Focusing on real-world measures of *reduction in outage frequency (SAIFI) and duration (SAIDI) compared to a baseline start year* is not a radical idea, but it is a good place to start. It can be tempting to try to develop a system to attribute outage reductions to particular grid modernization investments, but this should be avoided if possible, as it can result in a contentious and administratively-complicated process.

At the same time, it can be daunting to set a baseline number or year against which performance should be measured, as outages vary dramatically over time due to unpredictable weather events. Normalization can help; *using a rolling average of three years* is a common practice to reduce the impact of outlier years. Metrics for Energy Efficiency: Options and Adjustment Mechanisms from America's Power Plan provides greater detail on different approaches to weather- and economic normalization.[11]

If resilience to catastrophic events is of particular interest, as it has been on the U.S. East Coast, focusing on *the recovery of crucial electricity service to key first responders* may be one outcome of interest. In particular, regulators could put additional emphasis on SAIDI and SAIFI metrics for, e.g., hospitals, fire departments, community centers, police stations, schools, government buildings, and mental health institutions. This focus on outcomes would direct attention to critical parts of the distribution system, while still leaving appropriate flexibility for utilities to find the least-cost and most effective means to improve resilience for key service providers.

Measuring environmental performance

Grid modernization can unlock the value of distributed energy resources like rooftop solar, community solar, demand response, electric vehicle charging, and other customer-sited storage that provides or enables inexpensive zero-carbon energy. These technologies can help reduce pollution by directly avoiding polluting forms of generation or shifting energy demand patterns

[10] For an example of how to design an incentive around such a metric, see O'Boyle "Designing a Performance Incentive Mechanism for Peak Load Reduction: A Straw Proposal," 2016. http://americaspowerplan.com/wp-content/uploads/2014/10/Peak-Reduction-PIM-whitepaper.pdf.
[11] See Orvis, Robbie, et al., "Metrics for Energy Efficiency: Options and Adjustment Mechanisms." 2016.

to better align with the availability of solar and wind. They add flexibility to the system, which enables higher shares of clean electricity.[12] Ensuring the changes resulting from grid modernization investments materially impact decisions made at the bulk-system level (be that through wholesale markets or integrated planning, depending on the institutional structure of the region) is a crucial opportunity to improve environmental performance.

To ensure the emissions benefits of distributed generation programs in particular, some jurisdictions have adopted basic pollution standards for distributed generation (to ensure that programs are not incenting distributed diesel generators, for example).[13] Illinois took another approach to measuring emissions by adopting an *emissions intensity metric* (lbs/kWh) to guide its grid modernization efforts. The measurement determines the variable carbon value of a kilowatt-hour of electricity for all 8,760 hours in the year, to better understand which hours of the day are the dirtiest and help quantify the environmental benefits of grid modernization.[14]

Beyond those important ways to minimize pollution as part of grid modernization, several other indicators can focus attention on driving pollution reduction benefits. For example, growth in emissions-free distributed generation hosting capacity[15] or electric vehicle charging capacity compared to a baseline year, interconnection speed (average per customer), or total number of grid-connected distributed generation facilities (nameplate capacity, number of customers).

STEP 4. CREATE AN OPEN PROCESS TO SET TARGETS

Once metrics are selected, reasonable targets must be set. A transparent process should include plenty of time for stakeholder review and comment, and targets should be set far enough into the future to accommodate investment and program timelines. Consideration should be given to the unique context of each region or utility, and care should be given to place the targets within a range that represents a stretch, but not an unreasonable one. This is ultimately more an art than a science. That's why it is important to establish a transparent and predictable process for calibrating the targets based on real-world performance data. Laying out the process for calibration at target revision ahead of time will be critical to keeping investment risk low for utilities.

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[12] Orvis, Robbie & Sonia Aggarwal, "Grid Flexibility: Methods for Modernizing the Power Grid," Energy Innovation, April 2016. http://energyinnovation.org/wp-content/uploads/2016/05/Grid-Flexibility-report.pdf.

[13] See, e.g. 7-1144 Del. Admin. Code § 3 (2006), regulation to control the air emissions from DG units and emergency generators; Cal. Code Regs. tit. 17, § 94203 Table 2 (2007), requiring manufacturers of electrical generation technologies that are exempt from district permit requirements to certify their technologies to specific emission standards before they can be sold in California.

[14] "ComEd to Launch Unprecedented Environmental Measurement Tool." *Environmental Defense Fund*. 2016. https://www.edf.org/media/comed-launch-unprecedented-environmental-measurement-tool

[15] J. Smith, J., "Alternatives to the 15% Rule: Modeling and Hosting Capacity Analysis of 16 Feeders," Electric Power Research Institute, April 2015.
http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?productId=000000003002005812

Some regions, such as New York, have decided to set targets in individual utility rate cases. Other regions, such as Ontario, have set them through a central process based on benchmarks.[16]

STEP 5. CONSIDER TYING UTILITY REVENUE TO PERFORMANCE

The financial structure of a grid modernization program can impact its chances of success, as well as its overall affordability. Below we suggest some structural ideas to ensure that customers share in the program's economic benefits.

Option 1: Conditional rate of return

Utility regulators may consider conditioning the total allowed rate of return for the full portfolio of grid modernization investments on achieving net benefits for customers, or on performance against the metrics identified above.

The rate of return can require performance as a precondition, or scale with performance, or be a combination of these two approaches.[17] To weigh these options, policymakers should first consider the utility's investment incentives under the current revenue model[18] before altering the rate of return to align those incentives with the outcomes regulators seek from grid modernization.

For example, a utility might roll out smart meters with the intention of using them to reduce overall costs. But utilities may not be financially motivated to use the full range of smart meter capabilities over time, especially those that avoid the need for future capital investment. For example, utilities may be motivated to use smart meters to automate meter reading (an operational expense traditionally passed through to customers without a profit opportunity for the utility), but not motivated to use them to manage distribution system peak and avoid physical infrastructure upgrades (a capital expense, and thus a traditional opportunity for utility profit).

Assuming the utility gets cost recovery on the smart meters, a conditional return may link the returns on equity normally allowed under traditional regulation to achievement of peak demand reduction. The "precondition" approach would require the utility to demonstrate achievement of these goals before earning the return for shareholders. A scaling approach would increase the return as performance on outcomes improves.

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[16] Ontario Energy Board, Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach, Oct. 18, 2012. For a fuller discussion of benchmarking, see Fenrick, Steve & Lullit Getachew, Econometric Benchmarking of Toronto Hydro's Historical and Projected Total Cost and Reliability Levels, Power System Engineering, Inc., Sept. 19, 2014.

[17] See "Financial Rewards and Penalties" discussion in Woolf & Whited, "Utility Performance Incentive Mechanisms: A Handbook for Regulators," at p. 41-50. See generally Aas, D. & M. O'Boyle, "You Get What You Pay for: Moving Toward Value in Utility Compensation, Part 2: Regulatory Alternatives," America's Power Plan, June 2016. http://americaspowerplan.com/wp-content/uploads/2016/08/2016_Aas-OBoyle_Reg-Alternatives.pdf.

[18] See generally, S. Kihm et al., "You Get What You Pay For: Moving Toward Value in Utility Compensation, Part One – Revenue and Profit." June 2015. https://www.seventhwave.org/sites/default/files/you-get-what-you-pay-for-part-one-2015.pdf.

Option 2: Budget cap with shared savings

A "budget cap" describes a pre-approved total level of expenditures not to be exceeded for grid modernization efforts over a particular period, with a mechanism for sharing savings within the budget between the utility shareholders and customers. This would provide revenue certainty for utilities to invest in grid modernization, but also incent program managers to look for operational savings opportunities as long as certain quantitative outcomes can be met.

The metrics identified in this paper provide a starting point for the kinds of outcomes that can be evaluated. Grid modernization investment plans in California,[19] Massachusetts,[20] and Illinois[21] provide some examples of overall investment levels in distribution grid infrastructure to consider as potential sources for benchmarking other programs. The U.K. RIIO model[22] combines the revenue cap and conditional rate of return models – allowing utilities to capture operational savings and reap extra returns for good performance on outcome-oriented metrics.[23]

CONCLUSION

Grid modernization represents a monumental opportunity to achieve cleaner, more affordable, resilient electricity service. It is worth taking time at the beginning of a grid modernization effort to carefully consider how utility and third-party investments can contribute to an optimized, integrated grid. Regions can benefit from determining which outcomes are most important to them, developing quantitative metrics associated with those outcomes, and begin to compensate utilities based on their performance against those metrics.

[19] See California Distributed Resource Proceeding Overview, California Public Utilities Commission, R. 14-08-013 http://www.cpuc.ca.gov/General.aspx?id=5071.

[20] See Massachusetts Grid Modernization Homepage http://www.mass.gov/eea/energy-utilities-clean-tech/electric-power/grid-mod/grid-modernization.html.

[21] See Commonwealth Edison Company, "Overview of Energy Infrastructure Modernization Act," June 2014. http://www.eesi.org/files/Anil-Dhawan-061814-original.pdf.

[22] https://www.ofgem.gov.uk/network-regulation-riio-model

[23] For a summary of RIIO, see Fox-Penner, P., D. Harris, & S. Hesmondhalgh, "A Trip to RIIO in Your Future?", Public Utilities Fortnightly, Oct. 2013.