STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

<u>In the matter of</u>

Docket No. **IR 15-296**

INVESTIGATION INTO GRID MODERNIZATION

DIRECT TESTIMONY

OF

PAUL J. ALVAREZ
AND
DENNIS STEPHENS

ON BEHALF OF
THE OFFICE OF THE CONSUMER ADVOCATE

September 6, 2019

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I. INTRODUCTIONS

Q. Mr. Alvarez, would you please state your name, business address, and occupation?

A. My name is Paul J. Alvarez. My business address is Post Office Box 150963, Lakewood, Colorado 80215. I am president of The Wired Group and I am providing this testimony in my capacity as a consultant to the Office of the Consumer Advocate (OCA).

Q. Please describe your formal education and professional experience.

A. I received a bachelor's degree in business administration from the Kelley School of Business at Indiana University in 1984 and a master of management degree from the Kellogg School of Management at Northwestern University in 1991. After 15 years in Fortune 500 product development and product management, I entered the utility industry in 2001 with responsibilities that focused on demand-side management and renewable energy program development and rate design, marketing, and impact measurement. These experiences led to two unique projects involving the measurement of grid modernization costs and benefits, which revealed the limitations of current utility regulatory and governance models.[1,2] I formed the Wired Group in 2014 to focus exclusively on consumer and business advocates' need for expertise in grid modernization and utility performance measurement. I have since testified before

[1] Colorado PUC 11A-1001E. *SmartGridCity Project Evaluation Summary*. Exh. MGL-1. Dec. 14, 2011.

[2] Ohio PUC 10-2326-GE-RDR. *Duke Energy Smart Grid Audit and Assessment*. June 30, 2011

regulators in nine states, and served as a consultant to consumer and business advocates in nine other states.

I am the author of *Smart Grid Hype & Reality: A Systems Approach to Maximizing Customer Return on Utility Investment*, a book originally published in 2014 and revised for its second edition published in 2018. I am also the developer of the Utility Evaluator, an Internet-based application which benchmarks investor-owned utility performance on 30 different financial and operating metrics from publicly-available data (FERC Form 1, EIA Form 861, JD Power and Associates, state regulatory filings, etc.).

Q. Have you previously testified before this Commission?

A. No, but I have testified previously before the California Public Utilities Commission in connection with its evaluation of Southern California Edison's Request to Invest $2.3 Billion in its Grid to Accommodate Distributed Energy Resources (A16-09-001) on behalf of The Utility Reform Network in 2017; before the Kentucky Public Service Commission in connection with its Evaluation of Kentucky Utilities/Louisville Gas and Electric Smart Meter Deployment Plan (2016-00370 and 2016-00371) on behalf of the Kentucky Attorney General in 2017; before the Massachusetts Department of Public Utilities in connection with its Evaluation of Smart Meter Deployment Plans (15-120, 121, and 122) on behalf of the Massachusetts Attorney General in 2017; before the California Public Utilities Commission related to grid modernization in two Pacific Gas and Electric Rate Cases (A.15-09-001 and A.18-12-009) on behalf of The Utility Reform Network in 2016 and 2019; before the Kansas Corporation Commission in connection with its Evaluations of Westar

Energy's Proposal to Mandate a Rate Specific to Distributed Generation-Owning Customers (15-WSEE-115-RTS) on behalf of the Environmental Defense Fund in 2015; and before the Maryland Public Service Commission in connection with a Regulatory Reform Proposal to Base a Significant Portion of Utility Compensation on Performance in the Public Interest (9361) on behalf of the Coalition for Utility Reform in 2014.

Q. Mr. Stephens, would you please state your name, business address, and occupation?

A. My name is Dennis Stephens. My business address is Post Office Box 150963, Lakewood, Colorado 80215. I am employed by The Wired Group and I am providing this testimony in my capacity as a consultant to the Office of the Consumer Advocate.

Q. Please describe your formal education and professional experience.

A. I received my Bachelor of Science degree in electrical engineering from the University of Missouri at Rolla in 1975. I have over 35 years of experience in electric distribution grid planning, design, operations management, asset management, and the innovative use of technology to assist with these functions. Prior to joining the Wired Group in 2011, I spent my entire career with Xcel Energy (at its subsidiary, Public Service Company of Colorado), which serves more than 1.2 million customers in Colorado. In a series of electrical engineering and management roles of increasing responsibility, I served as director of electric and gas operations for the Denver metropolitan area, as director of asset strategy, and as director of innovation and smart grid investments for all of Xcel's eight-state service territory.

Q. Have you previously testified before this commission?

A. No, but I have testified before the California Public Utilities Commission in connection with the Southern California Edison general rate case (A16.09.001) on the subject of grid modernization investments, before the California Public Utilities Commission in connection with two Pacific Gas and Electric general rate cases (A.18.12.009 and A.15.09.001) in connection with grid modernization investments, and before the Colorado Public Utilities Commission (case 6609) on behalf of Public Service Company of Colorado in connection with claims of restitution for customer equipment damage resulting from transformer failure. In the Colorado proceeding, my employer prevailed as the result of my testimony.

Q. Gentlemen, what is the purpose of your testimony?

A. The OCA has engaged the Wired Group to assist with the OCA's participation in the Commission's ongoing grid modernization investigation in this docket. The OCA has asked us, as nationally recognized experts in grid modernization, to help the OCA both to evaluate proposals made by utilities (and other stakeholders) and to develop an approach to grid modernization that will protect and promote the interests of New Hampshire's residential utility customers while at the same time taking advantage of the capacity and expertise of the state's investor owned utilities (IOUs) with due regard for the interests of their shareholders.

Q. On May 29, 2019, the Commission issued Order No. 26,254 in this docket, instructing the state's electric utilities, and inviting stakeholders, to submit comments on or before September 6, 2019 on eleven enumerated grid modernization topics. Why is the OCA filing written testimony in response to this directive?

A. The OCA, in conjunction with the Acadia Center, Clean Energy New Hampshire, the Conservation Law Foundation, the City of Lebanon, and citizen activist Patricia Martin (all, like the OCA, members of the Grid Modernization Working Group described in the Procedural History section of our testimony), sought rehearing of Order No. 26,254 to argue that the Commission should move forward with the grid modernization investigation by commencing an adjudicative proceeding as opposed to conducting additional informal proceedings involving the submission of written materials and requiring participation in additional stakeholder meetings. The Commission denied the rehearing motion in Order No. 26,275 issued on July 26, 2019. The OCA continues to believe that the issues now ripe for determination in this proceeding are of sufficient consequence as to warrant resolution via the adjudicative process. However, rather than pursue appellate remedies at this time, the OCA has instructed us to treat this proceeding at its present juncture as if it were an adjudicative proceeding. We have therefore structured our comments so they are rendered in the form of testimony. In other words, what we are presenting here is the direct testimony we would offer if the Commission were to conduct an evidentiary hearing to consider the eleven topics that are listed on page 4 of Order No. 26,254.

II. PROCEDURAL HISTORY

The Commission opened this docket on July 30, 2015, to investigate the modernization of New Hampshire's electric grid. Given the breadth of the topic, the Commission invited all interested parties to participate in this proceeding. The Commission received comments on grid modernization through the summer and into the fall of 2015. Commission Staff (Staff) filed a status report on October 15, 2015. Staff's principal recommendation was that the Commission retain a facilitator/moderator to manage the investigation and an expert in grid modernization. In an Order instructing staff to implement its recommendation, the Commission also identified the goals of grid modernization in New Hampshire:

- Improve the reliability, resiliency, and operational efficiency of the grid;
- Reduce generation, transmission, and distribution costs;
- Empower customers to use electricity more efficiently and to lower their electricity bills; and
- Facilitate the integration of distributed energy resources.[3]

Staff engaged Raab Associates Ltd. (Raab) to facilitate and mediate a working group process, and Synapse Energy Economics to provide analytical services to Staff and stakeholders as needed. Over the ensuing months, Raab facilitated numerous stakeholder sessions and, on March 20, 2017, filed a report titled "Grid Modernization in New Hampshire" (Working Group Report). The Working Group Report discussed a number of policy issues and identified areas of consensus as well as areas of dispute among stakeholders. *We note that the Working Group included no participants with both a*

[3] Order No. 25,877 (April 1, 2016) at 2.

consumer perspective and technical experience in grid planning/operations.[4] Staff spent an additional two years investigating workable frameworks for modernizing New Hampshire's electric distribution grid in a regulated industry. Over this two-year period, Staff received training from, and worked in consultation with, the U.S. Department of Energy (DOE). Staff also examined the experiences of a number of states to identify a modernization paradigm that would be logical and derived from sound engineering practice, while allowing for scrutiny of the modernization process. *See* Staff Recommendation on Grid Modernization (January 31, 2019) at 7-8 (filed in this docket on February 12, 2019) (Staff Report). The Staff Report incorporated the policy recommendations of the Working Group Report and recommended a process and framework for utilities to develop integrated distribution system plans (IDPs) that would accommodate grid modernization.

Staff based its recommendations on the DOE Modern Grid Report, a guidance document developed as part of the DOE's grid modernization initiative. That guidance was developed with the input of the public utility commissions of California, New York, Hawaii, Minnesota, and the District of Columbia, and with the assistance of technical advisors, DOE Laboratories, DOE consultants, and electric utility and industry experts. *We note that the DOE consulted no experts with a history of representing consumer advocates in grid modernization proceedings for its Modern Grid Report.*[5]

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[4] Working Group Report at 4.

[5] US Department of Energy, Office of Electricity Delivery & Energy Reliability, *Modern Distribution Grid, Volume I: Customer and State Policy Driven Functionality, Version 1.1,* March 27, 2017, at 1; *Volume II: Advanced Technology Maturity Assessment, Version 1.1,* March 27, 2017, at 1; *Volume III: Decision Guide,* June 28, 2017, at 1.

The Staff Report left a number of issues for further refinement by New Hampshire stakeholders through working group sessions. Staff presented its report to participants in this docket at a technical session held on March 25, 2019. The Commission set a deadline of April 8, 2019, for written comments on the Staff Report, and scheduled a public comment hearing for April 12. The OCA filed comments on the Staff Report. Though the OCA addressed many grid modernization issues in its comments, the OCA also asserted its rights to an adjudicative proceeding, stating: "We share Staff's interest in moving forward expeditiously at long last, but believe the appropriate course of action is for the Commission to commence an adjudicative proceeding now, whose purpose would be to address in specific terms how the LCIRP [least-cost integrated resource planning] process will become the IDP (Integrated Distribution Planning) process (and specify which issues will not be cabined off as 'grid modernization' and will instead remain within the rate case realm)."[6] Following the public comment hearing, the Commission scheduled another technical session for stakeholder discussions of procedure going forward. In the secretarial letter scheduling the technical session, the Commission requested that stakeholders consider non-traditional litigation processes that could lead to an efficient presentation and resolution of issues in dispute. The technical session was held on May 15 and, on the following day, Staff filed a report on the technical session with recommendations for next steps in the investigation, including a list of grid modernization topics on which stakeholder comments would be accepted.

On May 17, 2019, the OCA filed additional comments, in which the OCA again requested that the Commission respect the OCA's right to an adjudicative proceeding as

[6] OCA Comments of April 8, 2019 at 17.

provided for in N.H. Code Admin. Rules Part Puc 200. In its order dated May 29, 2019, the Commission rejected this request on the basis that the proceeding does not represent a "contested case" within the meaning of the state's Administrative Procedure Act.[7] Though the OCA respectfully disagrees with this Commission determination, and believes the future record in this case will attest to the contested nature of the issues at hand, the OCA is submitting our testimony as its comments as provided in the Commission's Order. As foreshadowed by comments submitted by the OCA to date in this proceeding, our testimony will focus primarily on recommendations for a holistic IDP process to replace the LCIRP, to be employed to all proposed IOU distribution grid and business investments regardless of their nature, classification, or intended capability. *We do not recommend distinct planning processes for "modern" grid investments.*

Q. Please provide a preview of your testimony.

A. Our testimony will begin with background information on distribution planning in New Hampshire, why a replacement for the LCIRP is needed, and goals and strategies for an LCIRP replacement. With these goals and strategies in mind, we will describe the step-by-step IDP process we recommend in our capacities as the experts the OCA has retained with experience in both grid planning for investor-owned utilities and in representing consumer advocates in grid modernization proceedings before state regulators. This will represent the bulk of our testimony.

[7] Order No. 26,254 (May 29, 2019) at 5.

We will then provide the OCA perspective on other issues related to distribution planning and grid modernization listed in the Commission's May 29 order and offer summary thoughts and perspectives in conclusion.

III. DISTRIBUTION PLANNING: BACKGROUND, GOALS, AND STRATEGIES

Q. Why does the OCA believe improvements to the LCIRP process are needed?

A. Several industry developments and state policies are contributing to growing public and stakeholder interest in distribution planning, and which indicate that a successor to the LCIRP process is needed. State statutes and policies encouraging free electricity markets (RSA Chapter 374-F), electric energy efficiency (the Energy Efficiency Resource Standard, as adopted in Docket No. DE 15-137), and renewable energy (the Renewable Portfolio Standard, as implemented in Docket No. DE 14-104) have all but eliminated the need for utility-owned generating resources. At the same time, the divestiture of the last of Public Service Company of New Hampshire's generation assets last year (Docket Nos. DE 14-238 and DE 17-124) means that the era of the vertically integrated electric utility in New Hampshire has finally concluded. This leaves RSA 374-G, which concerns electric utility investment in distributed energy resources, as the only significant opportunity in New Hampshire for electric utilities to build generation facilities, limiting such investments to six percent of the utility's total peak load.

With minimal need for new generation resources, and with a decade required to plan, design, and build new transmission, IOUs are turning to distribution rate base growth as the best way to meet the earnings per share expectations the IOUs have established with Wall Street analysts and shareholders. This issue is not limited to New Hampshire, as IOUs across the U.S. have proposed exceptionally large increases in distribution rate base under the "grid modernization" banner, along with requests for enhanced cost recovery mechanisms. Yet IOU interest in increasing distribution rate base conflicts directly with customer interests, and state policies,[8] aimed at energy cost-effectiveness. *The conflict between IOU shareholder interests and customer interests in/state policy for cost effective electric energy indicates that a new, transparent, stakeholder-engaged process for determining the most appropriate level of distribution investment is required.*

Q. Can the Commission simply authorize the utilities to replace Least-Cost Integrated Resource Plans (LCIRPs) with Integrated Distribution Plans (IDPs)?

A. We are not qualified to render opinions about legal matters and leave any such arguments to the consumer advocate, who is an attorney. However, we are aware that RSA 378:38-a authorizes the Commission to waive certain LCIRP filing requirements in appropriate circumstances. The Staff Report assumes it is lawful

[8] *See, e.g.*, New Hampshire Office of Strategic Initiatives. New Hampshire 10-year State Energy Strategy (April, 2018).

for the Commission to replace LCIRP filings with IDP filings. *See, e.g.*, Staff Report at 21-25. We make the same assumption for purposes of our testimony, but it is not our intention to waive any rights the OCA might ultimately invoke in an adjudicative or appellate context to argue that any IDP process adopted by the Commission is consistent with the LCIRP statute as set forth in sections 37, 38, 38-a, 39, and 40 of RSA 378.

Q. Please describe the OCA's goals for a potential LCIRP Replacement.

A. The OCA recognizes New Hampshire's electric grid as a critical component of the state's economy. We view the state's electric grid as a strategic asset which can be used to retain and attract businesses to New Hampshire, providing jobs and improving citizens' quality of life. Indeed, the Commission was formed to ensure that high quality service is provided by the utilities at rates that are just and reasonable. As a result, the goal of an LCIRP replacement should be a process which secures the greatest benefits and risk reductions for customers, as well as state policy objectives, for the least amount of customer cost.

Q. Doesn't the existing LCIRP process already incorporate this goal?

A. Yes, but the ability of the existing process to secure the greatest benefits and risk reductions for the least amount of customer cost successfully, given the changing nature of distribution investments, is questionable at best. Add in the conflicting priorities among stakeholders, and the inadequacies of the existing LCIRP process become readily apparent.

Q. What do you mean by "the changing nature of distribution investments?"

A. Historically, distribution investments were largely non-discretionary, uncontroversial, and had few alternatives. When load growth demanded an increase in a circuit or substation's capacity, the utility provided it. When economic expansion required new circuits or laterals, the utility built them. When something broke, the utility replaced it. If a roadway was being expanded, the utility moved its poles. These "routine course of business" investments went largely unchallenged, as there were few alternatives. Today, IOUs are proposing distribution rate base increases for which "need" is questionable. IOUs are proposing:

- Grid-wide equipment change-outs to accommodate growing distributed generation (DG) in cases where section-specific upgrades would suffice;
- Section-specific upgrades and enabling technology platforms far in advance of when they are truly needed (in preparation for high levels of DG adoption, for example);

- Distribution rate base growth to improve reliability with no commitment to the level of reliability improvements the spending will deliver;
- Rate base growth which could have been avoided through service contracts at a lower total cost to customers;
- Rate base growth to reduce risks, such as cybersecurity or public safety, with no objective estimate of risk reduction size or associated value to customers.

These are only examples; we are aware of many more. The existing LCIRP process is simply not designed to prevent these abuses, or to cope with the changing nature of IOUs' distribution rate base growth proposals.

Q. What distribution planning process strategies do you recommend to avoid excessive and low-value IOU distribution rate base growth?

A. We believe the existing LCIRP process offers valuable features, such as transparency and stakeholder engagement. The transparency of the existing LCIRP process stimulates and encourages healthy stakeholder education and debate, choices informed by an understanding of trade-offs, and better data with which regulators can make decisions. The value of these has been proven as integrated resource planning has become a standard across the U.S, indicating that transparency and stakeholder engagement strategies should be retained *and* *expanded* in any process which replaces the LCIRP. In addition, a single, holistic grid planning and capital budgeting process should be designed to accommodate all potential distribution grid and business investments, be they traditional or "modern," discretionary or non-discretionary, enabling software or field equipment. Design of separate planning processes and/or cost recovery mechanisms for "modern" investments appears artificial to us, and primarily of benefit to IOU shareholders. (It also presents definition issues; whose definition will be used to classify investments or capabilities as "modern?") We also believe that any LCIRP replacement must be definitive, not just informational, and utilized specifically to establish IOU capital budgets. Finally, any LCIRP replacement process should provide some degree of IOU flexibility. Once a distribution plan and associated capital budget is approved, an IOU should retain some discretion to make changes within the budgeted amount. As examples, an IOU should retain the right to delay a low-priority project in favor of a project needed to accommodate unanticipated load growth, DG growth, or to replace equipment that fails during the plan period. To summarize, the process developed to replace the LCIRP must be transparent, holistic, definitive, and flexible.

Q. You introduced an interesting notion there, linking distribution planning to capital budgeting. Please explain.

A. We see distribution planning and capital budgeting as inextricably linked. We believe a distribution plan must be associated with a capital budget to be meaningful, and that every capital budget must be supported by a distribution plan. A distribution plan is meaningless without a capital budget to implement it, and a capital budget without an approved distribution plan to justify it exposes customers to unnecessary rate increases.

Q. Have other states implemented the type of distribution planning process you are recommending?

A. California's Distributed Resource Planning process probably comes the closest to the process we are proposing,[9] but given our experience testifying on behalf of consumer advocates in California investor-owned utility rate cases, we believe that process exhibits significant shortcomings. We are also familiar with the distribution planning processes specified by regulators in Massachusetts and New York, and find even greater shortcomings in those processes. Given our somewhat unique combination of both technical experience and consumer advocacy, we believe we are on the leading edge of distribution planning process development. However, others are now identifying the same shortcomings that we are. We are particularly heartened to see that the Department of Energy (DOE) is finally

[9] California PUC R.14-08-013. Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769. Initiated August 14, 2014.

beginning to appreciate the importance of distribution planning in the context of grid modernization. The first report on the topic by the DOE's Grid Modernization Laboratory Consortium to the National Association of Regulatory Utility Commissioners (NARUC), though short on details, certainly endorses most of the steps and features we describe in our recommended process.[10] The distribution planning process we describe below provides more details consistent with the DOE report guidelines.

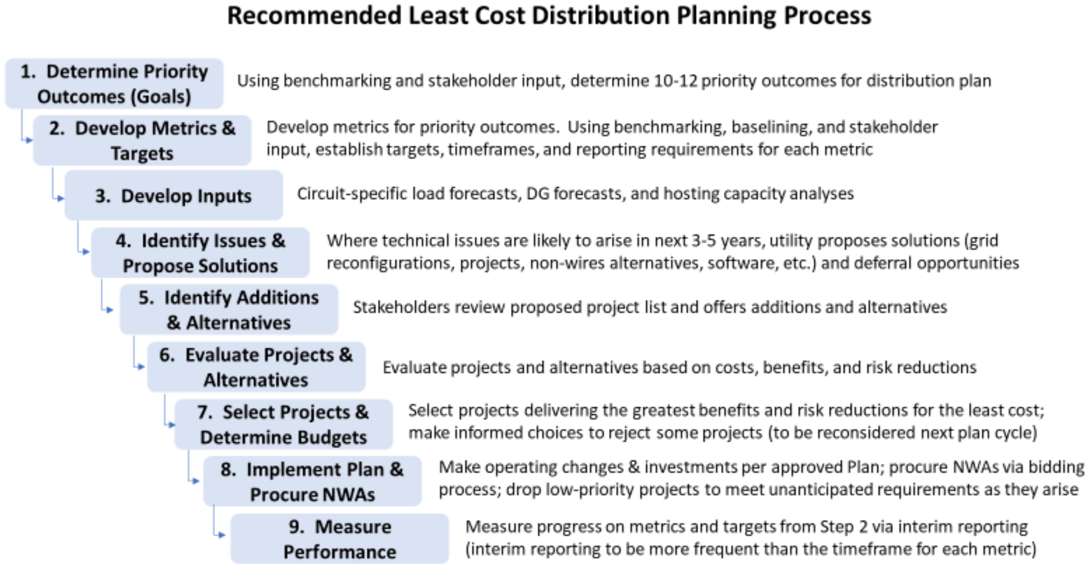
IV. A RECOMMENDED DISTRIBUTION PLANNING PROCESS FOR COMMISSION CONSIDERATION

Q. What are the components of the distribution planning process you recommend?

A. A rational and responsible process for developing a distribution plan and associated capital budget in a transparent, holistic, definitive, and flexible manner includes nine discrete steps. We list them below and follow the list with more detailed descriptions of each. Most regulators will probably prefer to hire independent facilitators to co-ordinate the development of each distribution plan. It is also important for regulators to define "stakeholders," as we do throughout this document, to include IOUs. The figure below summarizes the distribution planning process we recommend.

[10] DOE Grid Modernization Laboratory Consortium, "A Valuation Framework for Informing Grid Modernization Decisions: Guidelines. Report to NARUC" (March, 2019).

Figure 1: Summary of the OCA's Recommended Least Cost Distribution Planning Process



1. Stakeholders identify and prioritize distribution plan goals (outcomes).
2. Stakeholders define performance metrics, targets, timeframes, and reporting requirements for priority outcomes.
3. Utilities collect and publish distribution planning inputs.
4. Utilities propose a list of recommended distribution projects.
5. Stakeholders identify potential alternative and/or additional projects.
6. All potential projects are evaluated using one of three methods based on the nature of each project (non-discretionary; discretionary with readily quantified benefits; and discretionary with difficult-to-quantify benefits).
7. Stakeholders select projects and determine capital budgets.

8. Utility implements selected projects and procures selected alternatives through competitive solicitation.
9. Performance is measured using metrics and targets established in Step 2.

Step 1: Stakeholders Identify and Prioritize Distribution Plan Goals (Outcomes)

Q. Please describe the first step in your recommended distribution plan development process.

A. The distribution planning process must begin with the identification and prioritization of performance improvement opportunities or, in other words, the goals for an IOU's distribution plan. Avoiding this step can introduce critical errors in the resulting plan. For instance in Ohio, which does not utilize a transparent, stakeholder-engaged approach to distribution planning, First Energy has proposed $450 million in rate base growth for distribution platform modernization, which it expects primarily to "result in enhanced reliability of the system and outage restoration."[11] Yet of the three First Energy subsidiaries serving Ohio, only one (Ohio Edison, serving greater Akron) exhibits below-average reliability performance (measured by System Average Duration Interruption Index, or SAIDI, without Major Event Days) over the past five years relative to other US IOUs. First Energy's Cleveland Illuminating routinely delivers

[11] Ohio PUC Case No. Case No. 17-2436-EL-UNC. First Energy Application for Distribution Platform Modernization Plan Approval. December 1, 2017. Page 4.

above-average SAIDI results (four out of the last five years), and First Energy's Toledo Edison has ranked in the top 10 percent of all US IOUs on SAIDI for the last 5 years straight.[12]

Benchmarking performance in distribution basics -- reliability, affordability, operating efficiency, customer satisfaction, and the like – can therefore provide important guidance for distribution plan goals and goal prioritization. Stakeholders can help identify other goals, such as reducing the risk of DG interconnection delays, or reducing energy distribution inefficiency (for which all customers, and the environment, pay a price). Once identified, stakeholders can debate the relative merits and priorities of various goals, translating the roles of IOUs and stakeholders from opponents to co-contributors. In a sound distribution planning process, the role of the IOU changes from dominant ("Here's what we propose") to consultative ("If that's what you want, there are three ways to go about it, each with its own pros and cons.") Without an understanding of the goals of the investments, resulting distribution plans will lack focus.

[12] Reliability data is sourced from U.S. Energy Information Administration form 861, 2013-2017 inclusive, as compiled by the Utility Evaluator (www.utilityevaluator.com). Access is available by subscription.

Step 2: Define Performance Metrics, Targets, Timeframes, and Reporting Requirements

Q. Next, you recommend performance metric definition and target setting?

A. Correct. To add even more focus to IOU distribution plans, we recommend that stakeholders define performance metrics, targets, timeframes, and reporting requirements early in the distribution planning process. In this manner an IOU knows exactly how its distribution rate base growth will be judged, and can adjust its distribution project proposals accordingly. This early point in the distribution planning process is also ideal for measuring baseline performance and identifying historical trends, thereby establishing a basis for initial targets and timeframes. Benchmarking against the performance of other IOUs can also play a role in setting targets and timeframes. Finally, this is the time to determine performance reporting requirements. For a multi-year target, we suggest annual performance reporting; for an annual target, we suggest quarterly performance reporting. The idea is to hold the IOU accountable for performance improvements while minimizing opportunities for gaming through baselining and interim performance reporting. By knowing the starting point, and observing progress over time, stakeholders have greater opportunities to identify any changes IOUs might make in data gathering or data exclusion which would inaccurately indicate that a performance target has been met.

Q. Both the Grid Modernization Working Group report and the Staff Report in this proceeding mention performance metrics specific to grid modernization investments. Do you care to comment on that?

A. Yes, we have several comments to make regarding performance metrics generally. First, performance metrics should be kept to a few, critical performance issues. Like people, utilities can only focus on a limited number of priorities at any one time; too many metrics dilutes focus. The Hawaii PUC, in its current proceeding on performance-based ratemaking, has identified only 12 regulatory outcomes for performance metrics.[13] On a related note, as indicated previously, it is preferable to establish goals for distribution plans, not for individual investments. Though we can foresee one or two exceptions, such as for conservation voltage reduction, establishing goals for each major project will quickly cause metric overload, which in turn will cause an IOU to lose sight of distribution plan priorities. Further, metrics should be objective, not subjective (measurable), and based on outcomes, not processes. The metric "Dollars spent on pilot projects" means absolutely nothing to a customer.

[13] Hawaii PUC Case No. 2018-0088, Decision and Order 36326 ("Phase 1 Order"), at 7. Regulatory outcomes include affordability; reliability; interconnection experience; customer engagement; cost control; DER asset utilization; grid investment efficiency; capital formation; customer equity; greenhouse gas reduction; electrification of transportation; and resilience. The metrics to be used to measure progress on these outcomes are currently being negotiated by stakeholders.

Q. Can you provide examples of performance metrics, targets, and timeframes?

A. See the table below for some ideas. Note that these are just ideas, not recommendations. Stakeholders should determine metrics, targets, and timeframes in accordance with the goals for distribution planning established in Step 1.

Table 1: Example performance metrics, targets, timeframes, and reporting requirements

Priority Area	Metric	Target	Timeframe	Reporting
Affordability	Rate base per Customer	CAGR 2.0% or less	Annually	Quarterly
Reliability	Grid-wide SAIDI w/o Major Event Days	90 minutes	Annually	Quarterly
Grid Energy Efficiency	Average annual voltage per circuit	115 volts	Annually	Quarterly
Cost Control	O&M spending per customer, per year	$295	By year-end 2022	Annual
DG Interconnection	Approval time for compliant applications within circuit hosting capacity	2 business days	By Jan 1, 2023	Annual

Q. Where does the OCA stand on performance-based compensation?

A. The OCA is not taking a position on this question at this time. The top priority for our testimony in this proceeding is to help the Commission develop a replacement for the LCIRP process which holds utilities accountable for maximizing customer benefits and risk reductions for the least amount of rate increases. While we can see valid applications of performance-based compensation, the consumer protections and requirements for equitable administration of such programs are so extensive and specific as to extend beyond the scope of this docket. It is likely that rate cases, including the two that are pending (DE 19-057 for Eversource and DE 19-064 for Liberty Utilities) are the most appropriate settings for addressing issues related to how performance-based compensation can or should be implemented.

Step 3: Utilities Collect and Publish Distribution Plan Inputs

Q. With goals in place, and performance metrics and targets established, please describe the next step in your recommended distribution planning process.

A. The next step would be for utilities to collect and publish distribution planning inputs. This is the step most familiar to utilities, as they have been developing capital budgets from circuit-specific load forecasts for over 100 years now. There are new wrinkles to circuit-specific load forecasting, such as incorporating the impact of strategic electrification, and the use of probabilistic (vs. deterministic) forecasting techniques. The publication of inputs is new too, and is critical to achieving the OCA's goal for a transparent distribution planning process. Overall, however, the spirit of load forecasting remains unchanged: to estimate the loads a utilities' substations, circuits, and laterals will need to accommodate in the next five years, and using probability distributions, to identify likely overloads of equipment design capacities.

A new input to the distribution planning process is the DG forecast. DG forecasts, like load forecasts, are circuit-specific. They are designed to help a utility project where on their grids the capabilities to manage high levels of DG capacity will be needed first. Like probabilistic load forecasting, DG forecasts make use of (generation) profiles to improve forecast accuracy and detail. For example, photovoltaic solar panel generation on a cloudless day can be predicted by season of the year and by time of day based on the sun's position in the sky.

Finally, probabilistic load and DG forecasts by circuit are combined into hosting capacity analyses. Combined with other circuit-specific data, such as impedance, a utility's hosting capacity analysis identifies, by circuit, the additional amount of DG capacity which can be accommodated without significant circuit investment, as well as grid locations in which DG capacity and other distributed energy resources (such as targeted demand response or energy storage) could avoid or delay investments designed to increase substation, circuit, or lateral capacity due to load growth. The hosting capacity analysis also identifies circuits for which DG capacity increases will be limited absent grid investment.

Of course all forecasts and probabilistic models are only as good as the inputs, constraints, and assumptions incorporated therein. Distribution plans will clearly be impacted by these forecasts and models, making their accuracy and assumptions critical. All of these should be subject to stakeholder review and, if warranted, to re-working under revised inputs/constraints/assumptions. Stakeholders must scrutinize IOU work carefully. While utilities in New Hampshire may be uncomfortable with DG capacity equal to five percent of a circuit's peak demand, grid operators in California routinely deal with DG capacity exceeding 25 percent of a circuit's peak demand, and grid operators in Hawaii routinely deal with DG capacity exceeding 50 percent of a circuit's peak demand. Bi-directional power flow is not the mortal enemy IOUs often portray it to be.

Step 4: Utilities Propose a Recommended List of Distribution Projects

Q. What comes after distribution planning inputs are completed?

A. With known priority outcomes (goals and targets) and completed load forecasts, DG forecasts, and hosting capacity analyses, a utility is in position to identify and recommend distribution projects. As alluded to previously, utilities should compare load forecasts, DG forecasts, and hosting capacity analysis results to distribution equipment capacities to identify issues likely to arise on the grid in the next 3-5 years. Before proposing capital projects to resolve these issues, utilities should evaluate low-cost options such as grid reconfigurations. For most utilities, area engineers (those responsible for substations, circuits, and laterals in a defined geography) are the source for capital project recommendations. Software and control systems can also be included in capital projects, but should be driven by needs expressed by grid operators, not by executives interested in growing the rate base.

We believe the grid needs assessment described in the energy efficiency docket (DE 17-136) Settlement Agreement approved last year would represent a reasonable deliverable for this step.[14] As part of this step the IOUs should also identify opportunities to avoid or defer recommended capital projects through demand response and non-wires alternatives. In many states this is a specified exercise often called a "locational value of distributed energy resources" study, and we recommend such a study as part of any periodic distribution planning process. We are pleased to see that the Commission appears to be in the process of engaging a consultant to conduct such a study, as called for in the Commission's ongoing proceeding on alternative net metering tariffs.[15]

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[14] *See* Order No. at 26,207 (December 31, 2018) in Docket No. DE 17-136 at 10 (noting that each electric utility agreed in the 2019 plan update settlement agreement to provide a grid needs assessment in its next LCIRP filing).

[15] *See* Order No. 26,221 (February 20, 2019) in Docket No. DE 16-576 (Order Approving Scope of Locational Vanue of Distributed Generation Study). According to the "RFP" section of the Commission's web site, the Commission issued a request for proposals in April 2019, received five such proposals from consulting firms interested in performing such a study, and ranked them on August 6, 2019. We assume that the Commission is presently negotiating a contract with the winning bidder.

Step 5: Stakeholders recommend additional projects and alternatives to projects

Q. Shouldn't stakeholders participate in project identification?

A. Yes. Stakeholders should have an opportunity to review the utility's inputs as described above; the locational benefits study; and the grid needs assessment; and recommended operating changes and capital projects and estimated costs. Stakeholders should have the opportunity to question IOU "needs" and estimated project costs, to request supporting data and justifications, and to examine the likelihood of problems occurring to the extent the IOU projects. Stakeholders should be encouraged to propose other projects, or project alternatives, they believe might be better suited to accomplishing Plan outcomes at a lower cost.

Step 6: Evaluate projects/alternatives using methods appropriate to each project's type

Q. How should the projects and proposed additions and/or alternatives be evaluated?

A. All capital projects can be identified as one of three types: (1) non-discretionary; (2) discretionary, with readily-quantifiable benefits; or (3) discretionary, with difficult-to-quantify benefits. The type of evaluation to employ should be based on the type of capital project being evaluated, with stakeholders determining the most appropriate type for each project. We provide examples of common grid projects for each type in the table below, though some would argue that service interruption risk and outage duration reduction projects belong in the readily-quantifiable benefit category.

Table 2: Examples of Grid Investments by Evaluation Category

Non-discretionary Projects	**Discretionary Projects with Readily Quantifiable Benefits**	**Discretionary Projects with Difficult to Quantify Benefits**
• Load growth accommodation • DG accommodation • NERC/CIP compliance • Public works • (particular) Customer request (customer-paid) • Equipment failures • Compliance with law	• Smart meters • Automated conservation voltage reduction • Replace labor or service with capital • Enabling technology platforms	• Safety risk reductions • Cybersecurity risk reductions • Service interruption risk reductions • Outage duration reductions • DG interconnection delay risk reductions • Enabling technology platforms

Q. How do you recommend non-discretionary projects be evaluated?

A. Projects classified as non-discretionary, meaning that some action must be taken to meet a customer or regulatory requirement, or to address an equipment failure, should be evaluated on the basis of cost. Unless there is a compelling argument otherwise, when several optional solutions are available to satisfy a requirement, the solution associated with the lowest cost to customers should be chosen and added to the capital budget. Stakeholders must be diligent here. For example, there might be multiple ways to satisfy in technical terms a NERC (North

American Electric Reliability Corporation) or CIP (Critical Infrastructure Protection) requirement, but investor-owned utilities are likely to propose the most capital- intensive solution.

Our description may sound to many like an endorsement of the "least cost, best fit" approach a few state regulators have allowed, and which is endorsed by both the Working Group and Staff Reports. Our concern is that least cost, best fit is being applied in the absence of a transparent, holistic, definitive, and flexible distribution planning process. Without a sound planning process, IOU proposals are simply deemed to be required, with no oversight as to what projects are truly necessary to maintain safe and reliable service in the face of challenges, be they DG adoption, strategic electrification, or others. *In our informed opinion this Achilles heel has been exploited routinely by many IOUs in their grid modernization plans.*

When estimating costs, care must be taken to estimate equivalent (all else being equal) costs of projects to the customer, not costs to the IOU. This means that carrying charges customers will be asked to pay over the life of an asset should be added to the cost of all IOU investments to be evaluated. It also means that the remaining book value of any functional equipment removed prematurely must be considered as a cost to customers. (Customers will continue to pay for the original equipment without specific accounting remedies to the contrary, in addition to paying for the new equipment through rate increases. It is also worthwhile to note that failure to implement accounting remedies to prevent this situation constitutes a violation of the well-established 'used and useful' regulatory principle.) Care must be taken to ensure that the ongoing (over the life of the asset), incremental operations and maintenance costs associated with any capital project is not underestimated. Stakeholders must also rigorously evaluate the reasonableness of IOU capital cost estimates, as customers, not IOUs, will pay for cost-overruns absent Commission-approved protections and/or remedies. Capital bias discourages IOUs from concerning themselves too much with any variability in actual capital costs from estimates. Absent malfeasance, which is notoriously difficult to prove, shareholders benefit from project cost over-runs, as they are simply added to the rate base.

Q. How do you recommend discretionary projects with readily-quantifiable benefits be evaluated?

A. Discretionary projects with readily-quantifiable benefits must be evaluated using a standard benefit-cost analysis. The cost estimates used in a benefit-cost analysis should comply with all the guidelines described immediately above, and we recommend specific guidelines for benefit estimates as well.

As with project customer cost estimates, care should be taken when estimating the customer benefits from a project. Stakeholders should be wary of the size of benefit estimates, as IOUs are motivated by capital bias to over-estimate the benefits they can be reasonably certain of securing. Customers should be wary of the timing of benefit recognition, as many types of benefits, from reductions in O&M (operations and maintenance) costs to improvements in revenue recognition, only result in rate reductions after they are reflected in a rate case test year's accounting records. This could be several years, if not many years, after an IOU first secures such benefits, which accrue to shareholders in the interim. As an aside, we believe this timing/shareholder benefit issue to be one of the shortcomings of multi-year rate plans such as those proposed in the two pending electric rate cases in New Hampshire. Without due care, customers pay the rate increases on the assets from which shareholders derive benefits (until some future rate case).

Many benefits extend out many years, corresponding to the long lives of the assets that deliver them. But benefit periods should not be longer than asset lives, a tactic many IOUs have used to over-estimate the benefits of a project. Benefits should be discounted into present day terms, as a benefit delivered in project year 20 is worth much less to a customer than a benefit delivered in project year 3. Consideration should also be given to the use of customers' weighted average capital costs, rather than an IOU's capital costs, as a discount rate for calculating present value. Using a customer discount rate better reflects the opportunity costs of rate increases to residential customers (who make payments on mortgages, auto loans, and credit cards, not corporate bonds).

Stakeholders should also take care to ensure that all potential benefits from a distribution project are identified and maximized in the planning stages. By inflating project benefits or deflating project costs, IOUs are able to present a favorable project benefit-cost ratio while still ignoring large sources of potential benefit an IOU would rather not present. Most often, these are benefits which reduce sales volumes, such as automated conservation voltage reduction, or the energy efficiency and demand response potential associated with various capabilities related to smart meters.

With all benefits and costs estimated, the final step is to compare benefits to costs in the following manner:

Present value of customer benefits from project:	$10
LESS: Present value of the project's revenue requirement:	8
EQUALS: Net Present Value of the project to customers	$2

Clearly, projects with a negative net present value should be eliminated from further consideration. However, the corollary is not true; projects with a positive net present value should not automatically be selected for implementation. We will discuss why in the "Select projects and determine capital budgets" step later.

Q. How do you recommended discretionary projects with difficult-to-quantify benefits be evaluated?

A. Large, for-profit businesses often employ risk-informed decision support (RIDS) to make difficult choices among competing projects when capital is constrained and benefits uncertain. For illustration, consider the investment choices facing the Chief Operating Officer for General Motors. She must decide among three projects: replacing the roof on plant A, changing out the aging robots on one of the production processes in plant B, or replacing the vehicle painting booths in plant C. If all three projects cost about the same, and she only has enough capital for one project, she must weigh the likelihood and consequences of production delays associated with a leaky roof against those associated with robot breakdown against those associated with paint jobs which must be re-done. RIDS can help her identify, and justify, the best possible choice of the three.

Though less capital-constrained than for-profit businesses, IOUs are faced with similar project and risk reduction choices. In a particular distribution planning cycle an IOU could recommend investments in an almost infinite number of risk-reduction efforts. As examples, an IOU could spend capital to reduce stray voltage risk, wire down risk, cybersecurity risk, service interruption risk, or distributed generation interconnection delay risk. (Some projects are likely able to reduce more than one type of risk.) Unconstrained, an IOU with capital bias would like to spend a lot of capital reducing all of these risks. But customers ask, "How can the IOU maximize risk reduction value across all risk types for the least amount of capital?" Risk-informed decision support can help answer this difficult question by comparing equalized risk reduction levels relative to costs for various projects or alternatives, and selecting projects or alternatives on the basis of risk reduction per dollar.

Q. How do you recommend implementing RIDS?

A. The recommended RIDS process is somewhat similar to the overall distribution planning process. It consists of 6 steps, which we will describe in more detail:

1. Identify priority threats;
2. Characterize sources of risk/identify threat drivers;
3. Identify potential risk control measures (business process changes, service procurements, or capital expenditures);
4. Estimate cost of risk control measures (using guidelines listed above);
5. Estimate potential measures' risk reduction value (likelihood % x consequence $ x reduction in likelihood)
6. Develop list of control measures prioritized by risk reduction value

Once a list of control measures prioritized by risk reduction value is developed, Stakeholders help determine which control measures are selected, and associated costs added to departmental and capital budgets as appropriate. This part is described later in the "Select projects and determine capital budgets" step (7).

Q. Describe how threats are identified (RIDS Step 1)

A. Though the IOUs will play a leading role, a stakeholder process is used to identify top-priority threats. Top-priority threats could include contact with energized equipment; cybersecurity attacks resulting in service interruptions, customer data theft, or website disruption; DG interconnection delays; or others. Stakeholders should agree upon the top-priority threats IOUs should manage.

Q. Describe the "Characterize Risk Sources/Identify Threat Drivers" step (2).

A. Utilities will play a leading role here too. Consider the "contact with energized equipment" threat, for example. A utility might identify the following drivers as leading to contact with energized equipment: 1) A fault occurs; 2) the breaker fails to open; 3) the faulted line snaps (falling to the ground); and 4) a bystander touches the downed line, or the downed line starts a fire. Similar drivers should be identified for all top-priority threats identified in Step 1.

Q. Describe the "Identify Potential Risk Control Measures" step (3)

A. With threats and drivers identified, the utilities would propose potential risk control measures. Continuing with the wire down example, a utility might propose to increase circuit breaker testing frequency, or to replace circuit breakers of a certain type or vintage. Utility experience with the drivers, backed by data to the greatest extent possible, is the key to identifying risk control measures which are most likely to have a significant impact on the drivers and threats. Stakeholders must be vigilant here, as an IOU's capital bias encourages them to implement solutions which have not necessarily been proven to reduce the risks associated with a driver or threat.

Q. Is the "Estimate Cost of Potential Risk Control Measures" step (4) essentially the same as described above in the "non-discretionary project" evaluation section above?

A. Yes, and the guidelines we presented there should be followed in full here.

Q. Describe the "Estimate Potential Measures' Risk Reduction Value" step (5)

A. For example, the likelihood of a wire down event resulting in an injury or property damage on a particular circuit could be estimated as follows:

Table 3: Estimating the likelihood of an adverse event (example)

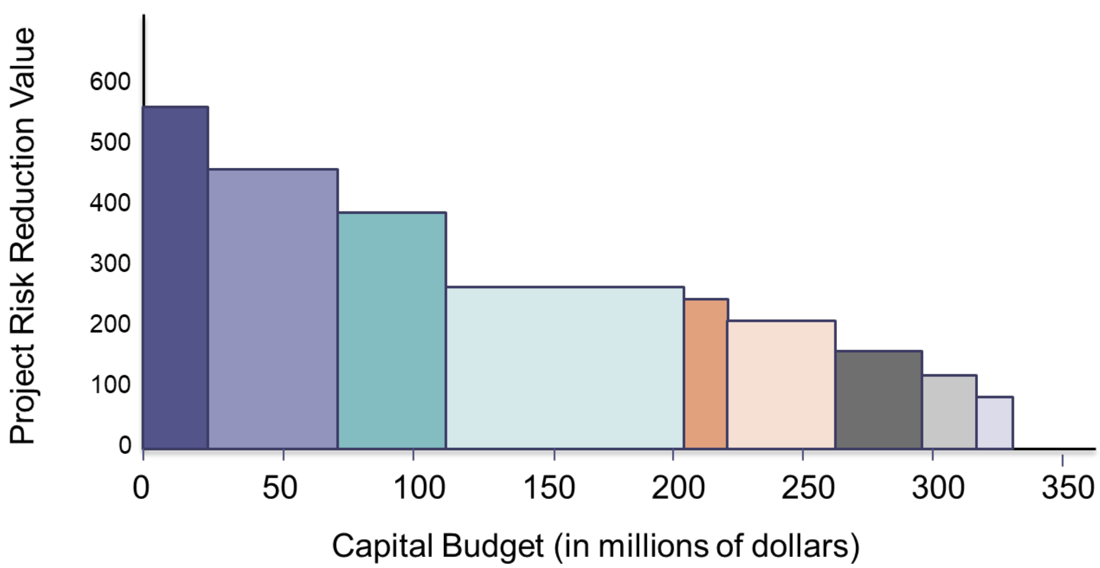
Item #	Event	Probability of occurrence per year
1	Fault	75%
2	Breaker stays open despite fault	1%
3	Line snaps and falls to ground	10%
4	Bystander injury or property damage	10%
	Combined probability (1 x 2 x 3 x 4)	.000075 (75 out of a million each year)

Likelihood could then be multiplied by the financial consequences to estimate the value of the risk reduction. For example, using an estimated valuation of $1 million per injury or property loss event, the value of eliminating this risk entirely would be $75 per circuit, per year. Let's assume further that a utility's proposed risk control measure is anticipated to reduce the likelihood that the breaker stays open by 50 percent, but leaves the other driver likelihoods unchanged. With a 50 percent reduction in likelihood associated with the driver, the value of the risk control measure would be $37.50 per circuit, per year ($75 x 50% reduction in likelihood). Establishing an economic value not only helps with the evaluation of an individual project, it facilitates comparisons between projects which reduce different (or multiple) types of risk. Cybersecurity risk is very different from safety risk, yet some way to compare the value of reducing each is important for prioritization when faced with multiple project proposals. Economic valuation of safety risk reductions may be distasteful for some, but without some common denominator, project prioritization is wholly subjective. Subjectivity is exactly the kind of circumstance RIDS is designed to avoid.

Q. What is the end result of the RIDS evaluations for discretionary projects with benefits which are difficult to quantify?

A. To conclude Step 6, potential risk control measures are listed in priority of risk reduction value. The figure below is a simplified example. The ranked project list is intended to provoke debate and thoughtful consideration of project selection by stakeholders, and will be discussed in the next distribution planning process step's description.

Figure 2: Example of a list of discretionary distribution projects prioritized by risk reduction value



With evaluations of all potential projects in all three project classifications – non-discretionary, discretionary with readily-quantified benefits, and discretionary with difficult-to-quantify benefits – complete, step 6 is almost finished. The deliverable from Step 6 is a portfolio of projects from which stakeholders can choose. At this point, stakeholders should take a step back and examine the entire portfolio for reasonableness. If stakeholders disagree about the portfolio's contents, it may indicate that assumptions, priorities, or other inputs to the process require adjustment. Several plan development process iterations may be required to end up with a portfolio suitable for Step 7 (project selection). We will describe this step (7) in the distribution planning process next.

Q. Before you go on to Step 7, the application of RIDS in distribution planning is certainly an interesting idea. How widespread is its use?

A. RIDS was first developed by NASA as a way to reduce run-away space program costs. NASA recognized it was economically infeasible to reduce all risks to zero, and that some method to prioritize and select risks for mitigation, with an eye on the cost of various mitigation options, was needed. Since then several government agencies have adapted the concept for their own uses:

- Army Corp of Engineers (to assess dams and levees, which the FERC has added as a guideline for hydroelectric dam safety assessments);
- Department of Defense (to improve its product acquisition process);

- Nuclear Regulatory Commission (to improve plant designs and operations).

Many corporations have adopted risk-informed decision support for prioritizing capital investments, as described in the hypothetical General Motors example presented above. The overview of a corporate RIDS process involving stakeholder engagement is documented in International Electrotechnical Committee (IEC) standard 31010, and incorporated into International Standards Organization (ISO) standard 55002 (regarding the implementation of Asset Management standard 55001). RIDS is not a new or untested practice.

Q. Is there evidence of RIDS use by IOUs?

A. Yes, though we believe RIDS use to be much more widespread than we can document, and greater than IOUs care to admit (given the ability of RIDS to moderate rate base growth). Mr. Stephens employed RIDS at Xcel Energy in his role as Director of Asset Management. We have also seen evidence of RIDS use by Puget Sound Energy[16] and, here in New Hampshire, by Liberty Utilities.[17] But perhaps the best documented use of RIDS is in California, where the PUC has

[16] Washington UTC UE-190529/UG-190530. Exh. CAK 1-t, Prefiled Direct Testimony of Catherine A. Koch (June 20, 2019) at 44.

[17] Docket No. DE 19-064, Liberty Utilities response to OCA DR 4-6 (August 7, 2019).

required its IOUs to use RIDS to develop safety-related investment plans. Of these IOU plans, Southern California Edison's plan comes closest to the RIDS process we describe.[18]

Q. Why do you believe the use of RIDS is more widespread than you can document?

A. We can think of two common use cases in which an IOU would benefit from the use of RIDS. One is the instance of combination gas and electric utilities. Until recently, electric use per customer was always increasing, while gas use per customer was always decreasing. In such a situation an IOU would much rather invest in electric distribution than gas distribution owing to earnings growth (through sales volume growth) between rate cases. We believe RIDS has been used by combination IOUs to reduce gas distribution investment, in favor of electric distribution investment, with as little an increase in gas distribution safety risk as possible. Another use case is the instance of multi-state utilities, in which an IOU is authorized to earn a higher rate of return in one state than in another. One can imagine RIDS being used to reduce investment in the distribution grid of states with lower rates of return with as little an increase in reliability and safety risks as possible. As almost half of US IOUs are either combination utilities or

[18] California PUC I.18-11-006. *Southern California Edison Company's (U 338-E) 2018 Risk Assessment and Mitigation Phase Report* (November 15, 2018).

multi-state utilities or both, we believe the use of RIDS to be widespread. Furthermore, since RIDS is designed to optimize (and thereby reduce) capital investment, we believe IOUs are reluctant to disclose its use. This is why we believe IOUs use of RIDS is much greater than we can document.

Step 7: Stakeholders select projects and determine capital budgets.

Q. So at this point in the process we have a lists of non-discretionary and discretionary investment proposals and alternatives, with each proposal/alternative having been evaluated using either the least cost approach, or the benefit-cost-analysis approach, or the RIDS approach. How do stakeholders select projects and determine capital budgets?

A. Let's begin with the non-discretionary projects, as this is the easiest: select the least cost option available to satisfy a requirement, be that option an operating or business process change, an IOU capital investment, or a non-wires alternative (generally, a contract with the provider of a service). Operating expenses associated with chosen solutions are simply added to appropriate departmental budgets, while capital associated with chosen solutions represents the starting point for IOU capital budgets. Risk can also be considered in the selection of the least cost option. For example, the fact that demand response is not quite as reliable as the capacity increase associated with reconductoring can be taken into account in the selection process. However, a low-cost solution to this issue is also available (contracting for somewhat more demand response than may be needed to avoid reconductoring, knowing that some amount of demand response may not be available when called upon).

Q. How should stakeholders determine capital budget additions for discretionary projects with readily-quantifiable benefits?

For discretionary projects with readily-quantifiable benefits, which are evaluated using benefit-cost analyses, project selection is not so black and white. As we noted previously, not every project with a favorable benefit-cost analysis (customer benefits exceed customer costs) should be selected and added to the capital budget. Three factors should be considered as stakeholders attempt to minimize capital investments/optimize capital budgets, and these can result in the rejection of projects despite a favorable benefit-cost analysis. One of these factors is the benefit-cost ratio; that is, the size of the benefit relative to customer costs. A project with a 3:1 ratio of customer benefits to customer costs should be selected over a project with a 2:1 ratio, all else being equal.

The second of these factors is the size of the investment required to deliver the benefit. A project with a benefit-cost ratio of 1.2:1, but which will cost customers only $1 million in rate increases, might take priority over a project with a benefit-cost ratio of 1.25:1, but for which customers will pay $350 million.

The third of these factors is the variability associated with delivering the benefits estimated for the customer costs estimated. Projects with low benefit-to-cost ratios are particularly vulnerable to the variability factor. A project with a benefit-to-cost ratio of only 1.25:1 can become negative if benefits are as little as 20 percent less than estimated, or if costs are as little as 25 percent higher than estimated. Projects with low benefit-to-cost ratios which are also characterized by significant benefit or cost variability should probably be excluded from distribution plans and capital budgets. At a minimum, such projects are examples of instances in which investment-specific performance metrics are called for, particularly if the investment is of large size (like automated conservation voltage reduction added to a third of an IOU's circuits).

Once stakeholders have selected projects for implementation, operating expenses and capital associated with selected projects are simply added to the appropriate departmental expense and capital budgets. Some will argue that the highly financial nature of the recommended approach to distribution planning lacks qualitative input, to address grid locations suffering from underinvestment (perhaps due to socioeconomic factors), or to account for extreme circumstances (such as incidents of extreme cold or heat). We respect these concerns, but suggest they be objectively addressed through the use of numbers and data. For example, if an area on the grid is perceived to suffer from historical underinvestment, there should be evidence of that in reliability data. If there is no evidence of a reliability issue, than either the underinvestment perception is misplaced, or the underinvestment is real but of no consequence. We have seen this in IOU requests to replace 4kV substations and circuits. As older parts of an IOUs grid, 4kV substations and circuits often serve older, less affluent parts of metropolitan areas. Yet in discovery, when asked for reliability data, we've observed 4kV circuits to be no less reliable than other circuits.

Regarding extremes in temperatures, these concerns can be addressed through probabilistic modeling in load forecasts. Our perspective on distribution planning can be summed up in the colloquialism "In God we trust; all others must bring data."[19]

Q. How should stakeholders determine capital budget additions for discretionary projects with difficult-to-quantify benefits?

A. While the selection of least cost projects requires almost no judgement, and the selection of projects evaluated via benefit-cost analysis requires some judgement, the selection of projects evaluated via RIDS requires a significant amount of judgement. This is not to say that RIDS is a subjective evaluation method, as it is designed to be as objective as possible given benefit uncertainties. However, the

[19] The aphorism can be traced to writer and radio personality Jean Shepherd (1921-1999) and his 1966 novel/memoir *In God We Trust: All Others Pay Cash*.

manner in which RIDS results are used in project selection can be somewhat subjective.

Q. Please explain.

A. The RIDS method was designed to enable capital budget flexibility. RIDS recognizes that for every reduction in capital budget, some amount of risk reduction will be lost. This is where the collective judgement of stakeholders comes into play. The question for stakeholders to answer is, how much risk is appropriate to accept? As the Commission reviews Figure 2, the relationship between customer costs and risk reductions becomes clear: the greater the risk retained, the lower the customer costs. RIDS is all about quantifying the trade-offs for stakeholders and regulators, enabling better collective choices and regulatory decisions through improved information and transparency.

An analogy may help drive this point home. We all know that SAIFI and SAIDI (the standard reliability metrics) can be driven to almost zero with enough money. But the law of diminishing returns applies; each capital dollar spent improves reliability less than the last capital dollar spent. While power could be almost perfectly available with enough money, few would be able to afford it. To date, we have collectively made an unconscious choice about the service interruption risk to accept. RIDS helps transition unconscious decisions we've collectively stumbled upon into subjects of informed debate and conscious choices. *Decisions reached through the collective wisdom of multiple stakeholders based on objective and available data will undoubtedly be better than decisions made by a single stakeholder which is biased by an interest in capital investment and which holds all data close to the vest.*

Q. Please continue.

A. Whereas an IOU is motivated by capital bias to spend as much capital as possible to reduce risk, stakeholders can (and should) evaluate risk reduction spending on a continuum. RIDS allows stakeholders to engage in open and informed debate about the levels (and types) of risk reductions for which customers should be asked to pay. By establishing the budget for discretionary projects with difficult-to-quantify benefits, stakeholders are also selecting projects and the amount of risk to retain rather than reduce. With RIDS, risk reduction efforts are transformed from a black hole for IOU capital to reasoned capital project selection. Furthermore, some stakeholders may prefer projects from the "readily quantifiable benefits" bucket over projects in the "difficult-to-quantify benefits" bucket, or vice-versa. So to some extent, all discretionary projects should be viewed as a portfolio of options from which stakeholders should select the most deserving for implementation. Stakeholder debate and negotiation should be used to resolve differences of opinion with the benefit of information made available in the evaluation step (6) we've been describing here.

Q. Is a distribution plan finished at this point?

A. Basically, yes. With projects of all three types selected, and associated capital budgets determined, the distribution plan is ready for submission to regulators for review and consideration. Some intervenors may choose not to be party to the resulting distribution plan, and may hold reservations which they pursue through hearings. But with a transparent, holistic, definitive, and flexible distribution plan development process, these hold-outs should be fewer in number, and their issues easier for regulators to discern, evaluate, and resolve. This has been the net result of the stakeholder engagement process the Commission has approved in connection with the state's Energy Efficiency Resource Standard, and we are confident that a similar approach will yield similar benefits in the context of distribution system planning.

Step 8: Utility implements selected projects and procures selected alternatives.

Q. Describe how an IOU would implement the distribution plan and procure selected alternatives.

A. The IOU simply implements the approved distribution plan, and seeks to recover costs through rate cases. Some distribution plans will incorporate the selection of non-wires alternatives, such as localized demand response or electric storage. To implement these parts of the plan, an IOU would need to procure services from third parties through a competitive solicitation process. In the event no third party responds with fees within the budgeted amounts, an IOU would implement a more traditional solution to meet the identified need.

Q. While distribution plan development appears to incorporate some level of flexibility, you've not yet addressed flexibility in implementation.

A. There are a couple of ways to provide implementation flexibility in the distribution planning process we propose. One option is to exempt capital projects below a specified dollar amount from the distribution planning process. This amount would likely be different for different IOUs, with larger IOUs granted a higher project exemption level than smaller ones. Stakeholders must be careful with such exemptions, as an IOU might try to conceal unsupported changes in equipment standards, or the establishment of unwarranted precedents, which could become large over time, by defining small pieces of larger wholes so as to fit under the specified dollar amount. Another option is to establish a non-specific capital budget for equipment as it fails.

Another idea is to allow IOUs to abandon lower-priority discretionary projects in favor of other projects as more urgent non-discretionary projects emerge between planning cycles. Proposals for real estate developments, public works, or high-voltage electric vehicle charging stations requiring grid upgrades may be tendered after a distribution plan is approved. In such cases, we propose IOUs be granted the authority to replace the capital budget intended for lower-priority discretionary projects with an equivalent amount of capital spending on emergent, non-discretionary projects. The lower-priority projects abandoned can simply be re-considered in the next distribution planning cycle, along with all the other potential projects which were not selected for the approved distribution plan. This is called a "portfolio approach" in the product development discipline and is highly relevant for distribution planning.

Step 9: Measure performance using metrics and targets established in Step 2.

Q. Is the final step in the process a rate case and cost recovery?

A. Yes, IOUs are expected to seek a return on and of capital approved in distribution plans through rate cases. But the more critical aspect of post-plan implementation from a customer perspective is performance measurement. IOUs should be required to deliver performance reports on the metrics specified in Step 2 at the frequencies specified for each metric. A critical part of performance measurement is to evaluate whether the projects implemented per the approved distribution plan are delivering the financial and risk reduction benefits estimated for the customer costs estimated. This feedback can be used in future planning cycles to develop ever more effective distribution plans.

Q. Some state regulators require distribution plan updates between planning cycles. What is your position on this?

A. We do not believe reports which simply confirm that an IOU is implementing the approved distribution plan would be very valuable. However, annual exception reports describing any deviations from the approved distribution plan would be *very* valuable. These annual exception reports could describe capital projects planned or implemented which were not part of the approved distribution plan because their cost was below the specified investment level described immediately above. Annual exception reports would also be the ideal opportunity to explain any lower-priority project substitutions made or planned as a result of emerging requirements as described immediately above.

Furthermore, rate cases represent an ideal opportunity to reconcile the capital an IOU actually spent to the capital budgets approved as part of a distribution plan. The Commission should establish such a reconciliation as a required and routine expectation of the rate case process going forward. Such a reconciliation will hold IOUs accountable for project cost overruns. Capital an IOU spends to replace equipment which fails would be exempt from scrutiny, as would any replacements of low-priority projects with emergent, non-discretionary projects (subject to prudence reviews, of course).

Q. Do you have any general recommendations for distribution planning processes?

A. Yes. Regarding timing, the distribution planning process we've described will be resource-intensive for all parties. While we believe the customer benefits to be well worth these efforts, we wish to avoid any planning efforts which do not deliver incremental value relative to incremental effort. These arguments for less frequent planning cycles are countered by arguments for more frequent planning cycles. Given the rapid changes the distribution business is likely to face in coming years, we are concerned that distribution planning cycles which are too infrequent are likely to miss capital conservation and technology-leveraging opportunities. Given the links between distribution planning and capital budgeting we propose, we are also concerned that infrequent distribution planning cycles could become unwieldy. A three-year planning cycle seems about right to us, and strikes the right balance between resource requirements, value, opportunity cost, and capital budget complexity concerns.

On a related note, given that there are three IOUs in New Hampshire, we ask the Commission to consider staggering distribution planning cycles such that no more than one IOU distribution plan be developed in any calendar year.

Q. Any other overall comments?

A. Yes. It is clear from both emerging issues in distribution planning and our recommendations in this docket that stakeholders must become better educated on technical issues and concepts in electric distribution. Stakeholders may not have the resources or bandwidth to secure the technical resources required to adequately challenge IOU technical representations, justifications, estimates, assumptions, and other aspects of electricity distribution likely to arise as stakeholder engagement in distribution planning grows. Some Commissions have employed an Independent Professional Engineer to serve as an unbiased evaluator of technical issues as they arise in distribution planning, and we believe such a role is important for New Hampshire stakeholders to have available. It may be that the best organization to house such a role is the consumer advocate's office, given its consumer protection mandate. But perhaps most importantly, regardless of where the independent technical resource sits organizationally, it is critical that such a role be filled by someone with electric distribution grid planning and operations experience.

V. COMMENTS ON OTHER DISTRIBUTION PLANNING AND GRID MODENRIZATION ISSUES

Q. In the course of describing your recommendations for a distribution planning process to replace the LCIRP process, you have covered many of the 11 Staff Report topics for which the Commission has requested input. Do you care to make comments on other issues in the list you've not addressed so far?

A. Yes. In the course of this testimony we have addressed six of the 11 Staff Report topics, including 1) Cost effectiveness methodology; 4) Hosting capacity/locational value analysis/interconnection; 5) Annual reporting requirements; 9) Consumer Advisory Council/stakeholder engagement; 10) Capital budgeting process; and 11) LCIRP/IDP integration. We would also like to comment on remaining five issues: (2) Utility cost recovery, (3) Utility and Customer Data and Third Party Access, (6) Rate Design Policy, (7) Strategic Electrification, and (8) Consolidated Billing/General Billing.

Q. Please provide your perspective on utility cost recovery.

A. All across the United States, state legislators and regulators are encouraging IOUs to invest more in their distribution grids through preferred cost recovery. Here in New Hampshire, both the Working Group Report and Staff Whitepaper on grid modernization endorse the concept. *We would like to caution the Commission in following other states' leads in cases where value to customers has not been proven.* Our experience in states considered leaders in distribution planning, such as California and Massachusetts, bears this out. Our experience is confirmed by nationwide, publicly-available financial and operating data submitted by IOUs on FERC Form 1 and EIA Form 861. The following three charts indicate the results of dramatic growth in distribution investment by US IOUs in recent years. Despite falling demand and energy use per customer, IOU distribution investment has grown three times faster than the rate of inflation. Yet reliability has deteriorated (as measured by SAIDI without major event days) and O&M spending has tracked largely with inflation (no savings for customers).[20]

[20] Data is sourced from U.S. EIA form 861, 2013-2017 inclusive, and US FERC form 1, 2010-2017 inclusive, as compiled by the Utility Evaluator (www.utilityevaluator.com). Access is available by subscription.

Figure 3: US IOU distribution investment relative to inflation, energy use, and demand

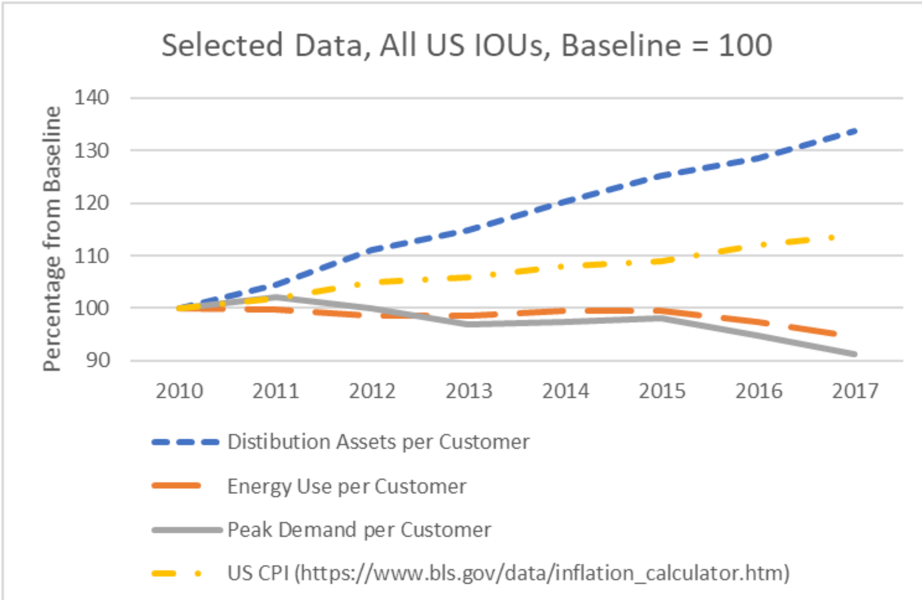


Figure 4: US IOU distribution investment relative to reliability performance

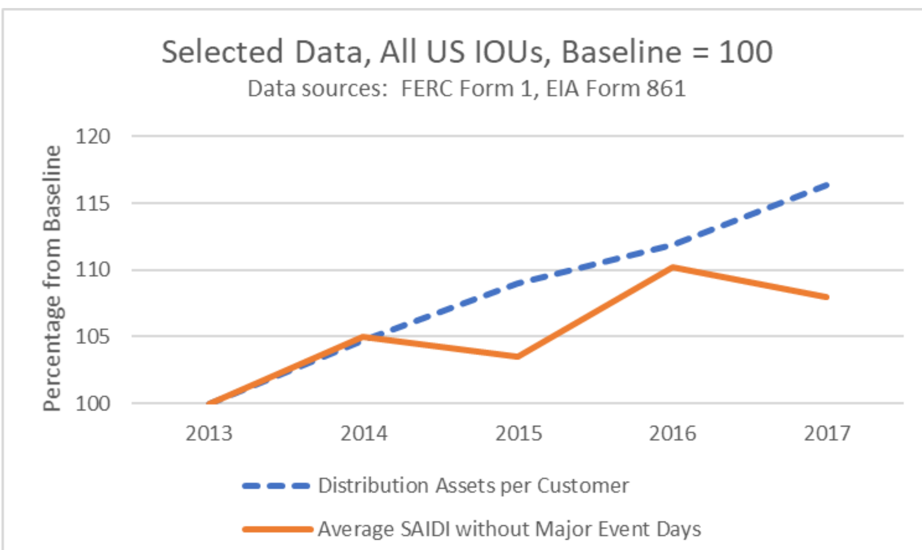
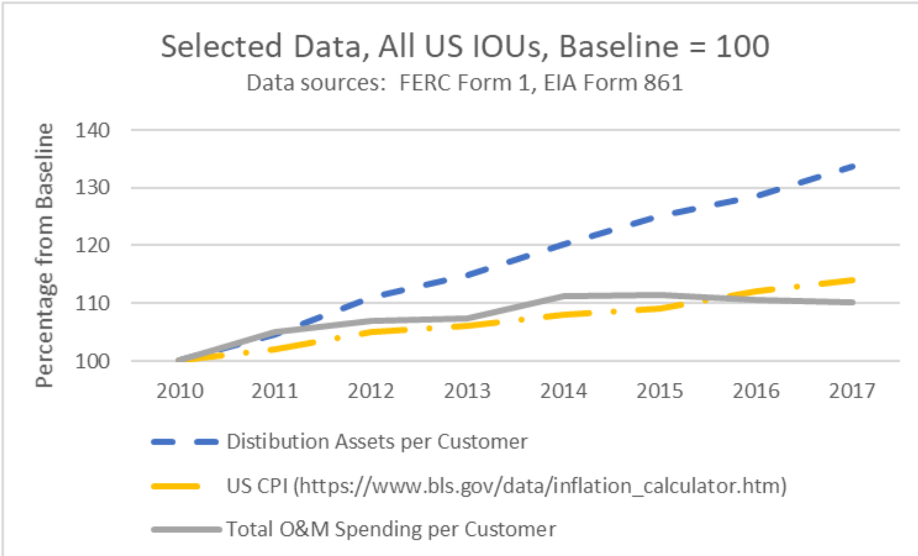


Figure 5: US IOU distribution investment relative to inflation and O&M spending



No one appears to be questioning the value delivered by exceptional distribution rate base growth, the wisdom of incremental investment incentives, or the "need" for grid modernization. The reality is that IOUs have been predicting shortcomings in their grids, investing to remedy those shortcomings in advance of problems, recovering their prudent investments, and rewarding shareholders for over 100 years now. That is their job, and they are compensated by an authorized rate of return on equity to do it. While distributed generation is growing, the reality is that New Hampshire is at least a decade behind adoption levels in states like California and Hawaii. While the grid does indeed need to be prepared to accommodate high levels of DG, the realities are that associated technical challenges are manageable, and that management strategies and tactics can be implemented locally as high levels are approached on specific circuit locations. While IOUs warn of impending problems which can only be avoided through huge capital expenditures, the reality is that distribution planning can help manage IOU capital bias while maintaining reliability. While other states burden their economies with incremental

IOU investment incentives, and the accelerated rate base growth and rate increases which are certain to follow, the reality is that IOUs already have an incentive to invest in their grids, and will do so without any incremental incentives. To summarize, *we can see no justification for providing enhanced cost recovery for so-called "modern" grid investments, whatever the definition for those might be, and strongly encourage the Commission to question the need and value of doing so.*

Q. Please provide your perspective on "Utility and Customer Data and Third Party Access."

A. Legislation on this subject – specifically, Chapter 286 of the New Hampshire Laws of 2019 – goes into effect on September 17, 2019, having been signed into law 60 days previously. Introduced as Senate Bill 284 and titled "An Act establishing a statewide multi-use online energy data platform," this measure was introduced at the request of the OCA, which drafted the initial proposal and played a key role in shepherding the bill through the enactment process. SB 284 paves the way for the creation of a secure, centralized data platform for the purpose of collecting, managing and sharing granular energy data generated by the utility and behind the meter (non-utility) data. The platform will enable standardized, opt-in, consent-based sharing of customer data from all three electric IOUs as well as natural gas utilities – along with, potentially, water utilities, the New Hampshire Electric Cooperative, and municipal utilities. The bill requires the Commission to open a proceeding within 90 days of the effective data to address issues of governance, development, implementation, as well as standards for data accuracy, data retention, availability, data privacy, and data security.

Although we did not participate in the development of this legislation, we note with approval several key elements in the bill. First and foremost of these is the requirement that data sharing comply with the Connect My Data standards developed and maintained by the non-profit Green Button Alliance. We understand compliance costs to be reasonable relative to the open market, energy efficiency, and customer benefits that compliance with these standards are likely to deliver. We also note that five states have already mandated IOU compliance with these standards in recognition of these benefits. Of course the decision to authorize a third party's access to energy data should always remain with each individual customer, and the protection of personally-identifiable customer data must remain sacrosanct. We also see benefit in making anonymized data available for legitimate research purposes. SB 284 mandates these approaches.

Q. Where do you stand on public access to utility system data, such as in the instances you describe in your distribution planning process recommendations?

A. Quite honestly, we feel most Commissions provide confidentiality protections to IOU information too readily. IOUs are monopolies, meaning that valid needs for trade secret protections are extremely rare. Other than in highly-specific and limited instances of cybersecurity-related information, there is no reason why any of the reporting needs referenced in our distribution planning process recommendations -- from load forecasts, DG forecasts, and hosting capacity analyses to grid needs assessments, locational value studies, cost and benefit estimates, and threat drivers/likelihoods -- shouldn't be made conveniently and publicly available.

Q. Please provide your perspective on Rate Design Policy.

A. In concept, rate design should follow distribution planning where appropriate. For example, if a smart meter investment is justified by time-varying rates, such rates should be designed and offered in a manner consistent with the maximization of time-varying rate benefits. While on the subject of time-varying rates, we believe strongly that the option for residential customers to selected traditional, flat rates per kWh be maintained.

On a separate rate design issue, we are familiar with and appreciate the role of cost causation in allocating costs among customer classes. However, we believe some grid modernization investments, and in particular those designed for reliability improvement, may justify a departure from the cost causation construct. Consider the fact that the economic benefits of reliability improvements accrue vastly more to commercial customers than residential customers. In fact, the U.S. Department of Energy's Interruption Cost Estimator allocates only 2 percent of reliability improvement benefits to residential customers.[21] A departure from pure cost causation is likely called for in such an instance, consistent with the principle of rate design equity, to ensure that commercial customers don't benefit from reliability-related investments at residential customer expense.

Finally, we are concerned that smart meter capabilities will be used to force new rate designs on customers, such as a default approach to demand charges. While there are many reasons why demand charges are inappropriate for residential customers, the

[21] Accessible via the Internet at https://icecalculator.com/home.

adverse impact on conservation is among the most critical in our minds. As the rate per kWh is typically much lower in a demand-based rate than it is in a traditional, energy-oriented (kWh) rate, the incentive for residential customers to conserve falls when they move to demand-based rates. As conservation is a goal established by the New Hampshire legislature, rate designs which compromise conservation, such as default demand charges (as well as increases in the monthly customer charge), should be discouraged.

Q. Please provide your perspective on Strategic Electrification.

A. In general, we see strategic electrification as a distribution planning issue, and not a grid modernization issue. As we've indicated in this testimony, IOUs have been forecasting load growth and preparing the grid in advance for such growth for over 100 years now. As long as IOUs appropriately forecast load growth due to strategic electrification, and do not intentionally over-estimate load growth from strategic electrification, the planning process we recommend should be adequate to prepare the grid for strategic electrification (from a grid investment standpoint). Another wise preparation is the development of electric vehicle charging rates which encourage off-peak charging, but we see that as outside the scope of distribution planning (assuming, of course, that IOUs appropriately account for the impact of such rates in load forecasts).

Q. Please provide your perspective on Consolidated Billing/General Billing.

A. The supplier consolidated billing option does not appear to be a significant issue to us, but serves as an excellent example of the practicality of the distribution planning process we recommend and describe in these comments. Like any other discretionary distribution investment, a stakeholder (in this case a retail energy supplier) could recommend that consolidated supplier billing be considered in Step 5 of the distribution planning process. As a potential investment with a benefit that can be readily quantified, an IOU would evaluate the idea through a benefit-cost analysis in compliance with the guidelines we described in Step 6 of the process. The results of the benefit-cost analysis would be subject to stakeholder review and critique as described in Step 6. Once stakeholders were satisfied with the reasonableness of the benefit-cost analysis, if the costs exceeded the benefits, the idea would be rejected. If the benefits exceeded the costs, the potential project would become part of the portfolio of projects reviewed by all stakeholders as part of Step 7 (project selection and budgeting). It could still be rejected by stakeholders at that point for any of the reasons we discuss in our description of Step 7.

Q. Are there other policy and strategic project concepts currently being debated in New Hampshire which could be addressed by the distribution planning process you recommend?

A. Absolutely. In fact, the process we recommend could be used to introduce, evaluate, and consider any concept stakeholders or policymakers come up with. Current New Hampshire examples include:

- The opportunity for municipalities to adopt opt-out Community Choice Aggregation in SB 286, and due to become law in October;
- Time-variant rate tariffs, products and services;
- Statewide, single portal access to all electric, natural gas, water usage, at the premises level;
- The Statewide centralized data platform contemplated by SB 284; and
- A statewide high bandwidth communication network.

VI. SUMMARY CONCLUSIONS ON DISTRIBUTION PLANNING AND GRID MODERNIZATION

Q. Do you care to provide any summary conclusions on distribution planning and grid modernization?

A. Yes. In this testimony we have described rational approaches to distribution planning and grid modernization which we believe will deliver the distribution grid New Hampshire will need in the future at just and reasonable rates. The approaches we've described offer something of value to all parties, including IOUs.

Q. What value do your recommendations provide to customers?

A. Customers in general, and the New Hampshire economy more broadly, are clearly the focus of our recommendations. If the Commission chooses to follow these recommendations, customers will benefit in three ways. First, rate increases will be held to a minimum. Second, customers will secure greater benefits per dollar of rate increase. Third, the New Hampshire distribution grid will be able to accommodate the level of DG capacity customers care to install, as well as the level of electrification they care to pursue, at a reasonable cost to all.

Q. What value do your recommendations provide to regulators?

A. Our recommendations offer several types of value to New Hampshire regulators. Perhaps most importantly, the recommendations will improve the New Hampshire economy by avoiding low-value rate increases employers would otherwise pay, an outcome of great interest to regulators and the Legislature. Although more difficult to quantify, the recommendations will also enable regulators to make more informed decisions by providing them with more objective and understandable information about the impacts and trade-offs of various grid investments. We believe the OCA's recommendations will also reduce regulator reliance on IOUs' technical representations and justifications, thereby increasing the confidence with which regulators will consider and challenge IOU requests. Last but perhaps most importantly, the process we recommend will allow regulators to advance state and Commission policy objectives at the least possible cost to the New Hampshire economy, including the Commission's goals for grid modernization:

- Improve the reliability, resiliency, and operational efficiency of the grid;

- Reduce generation, transmission, and distribution costs;
- Empower customers to use electricity more efficiently and to lower their electricity bills; and
- Facilitate the integration of distributed energy resources.[22]

Q. What value do your recommendations provide to IOUs?

A. Though IOUs will likely see these recommendations as challenging to shareholders' and managers' interests, there are some legitimate silver linings in our recommendations for IOUs to consider. Probably the greatest of these is a reduction in the risk of cost disallowance. Rate base increases backed by a distribution plan developed through a transparent, holistic, definitive, and flexible planning process will be difficult for a Commission to reject. Another benefit will be a change in IOUs' role. Today, IOUs make proposals which stakeholders critique. Each stakeholder pursues its own interests, putting IOUs in the difficult position of opposing all stakeholders. Using the process we recommend, IOUs transition from the role of an opponent to the role of a consultant. Utilities will have an opportunity to become trusted partners and collaborators in a paradigm that respects their expertise and responsibility to assure safety and reliability, while seeking a reasonable ROI for shareholders. Finally, when IOUs are in sole control of distribution investment decisions in conditions of uncertainty, they run the very real risk, if not certainty, of making investments which will be proven errant with the benefit of hindsight. With the benefit of stakeholder input, IOUs are less likely to make poor decisions. Furthermore, even poor decisions can be cast as stakeholder-wide choices, not

[22] *See* Order No. 25,877 (April 1, 2016) at 2 (adopting these goals in defining the scope of the instant proceeding) and Working Group Report at 1 ("embracing" these goals and describing "further benefits").

IOU choices, when such choices are made with the support of engaged stakeholders. This significantly reduces the pressure on IOUs to accurately predict future states.

Q. What value do your recommendations provide to other Stakeholders?

A. Our recommendations provide non-utility stakeholders with some of the same benefits our recommendations offer to regulators. For instance, the recommendations offer more transparency to stakeholders, and more objective and understandable information about the impacts and trade-offs of various grid investments. Over time, we believe a stakeholder-engaged distribution planning process will produce stakeholders who are more educated and informed regarding technical distribution issues and distribution technologies, leading to more valuable regulatory processes. This has happened in integrated resource planning over the last few decades, and we anticipate similar benefits ahead for stakeholders regarding distribution planning.

Q. Do you have any final observations on distribution planning and grid modernization?

A. Yes. In its recent order denying the rehearing motion filed in this docket by the OCA and other parties, the Commission stated that at present it is "seeking to determine whether the stakeholders agree on any of the eleven issues" on which the Commission has requested comment.[23] The Commission stressed that in declining to commence adjudicative proceedings at this time, it was not compelling parties to participate in any

[23] Order No. 26,275 (July 26, 2019) at 3.

alternative dispute resolution efforts and was reserving for future determination "what process to utilize to resolve the non-consensus issues."[24] We interpret this as an expression of hope that some if not all of an approach to distribution planning and grid modernization might still be achieved by agreement of the stakeholders in New Hampshire given the more than four years of effort that have been expended to date.

The OCA shares these aspirations. In that spirit, we hope that the utilities and other stakeholders will consider our testimony with an open mind. We have proposed an approach to grid modernization that will surely make our three investor-owned utilities more accountable to the public while potentially limiting certain capital expenditures they would have otherwise made under the existing paradigm of least-cost integrated resource planning. But, as we have explained, our proposal will yield benefits that accrue to both utility shareholders and utility customers. The OCA asked us to prepare this testimony, and to develop the recommendations we have described here, because it is serious about replacing a planning model designed for Twentieth Century vertically integrated utilities with one that will truly serve the needs of Twenty-First Century users of the grid. New Hampshire has the time to do this right, given the relatively nascent state of distributed energy resources relative to other states. While we are optimistic that the outstanding issues can be resolved through discussion and consensus-building, we are ready, willing, and able to defend this testimony in an adjudicative setting should that become necessary if consensus eludes the collective efforts of the parties.

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[24] *Id.*

Q. Does this conclude your testimony?

A. Alvarez: Yes, it does. Stephens: Yes, it does.