STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISSION

IR 15-296

ELECTRIC DISTRIBUTION UTILITIES

Investigation into Grid Modernization

Guidance on Utility Distribution System Planning
And Order Requiring Continued Investigation

O R D E R   N O. 26,358

May 22, 2020

This guidance document acknowledges a shift in utility distribution system planning that recognizes changes in customer needs, technology, and the electric utility industry. This document is the outcome of a legislatively mandated investigation into grid modernization[1] and several years of extensive contributions by, and consensus building among, a broad array of stakeholders led by Commission Staff.

The level of consensus achieved during this investigation should normalize the manner in which all the state's electric distribution utilities plan to accommodate new technologies, and reduce the number of issues to be litigated in each utility's subsequent least cost integrated resource plan approval dockets.

While reaffirming the value of least-cost integrated planning following the recently completed restructuring of New Hampshire's electric industry, the guidance that follows outlines a process for stakeholder input and engagement during the distribution system planning process

---

[1] "Grid modernization refers to a wide range of actions aimed at ensuring that the electric grid is more resilient and flexible, better able to integrate variable energy sources and demand side management, and capable of providing real-time information to help customers manage their energy use and reduce energy cost." New Hampshire Office of Energy and Planning, 10-Year State Energy Strategy at 17 (September 2014).

that appropriately balances the need to incorporate stakeholder input into the utility planning process and the need for shareholders of regulated utilities to remain accountable for investment decisions.

The order commits the Commission to exploring utility compensation structure reforms that can better align the interests of ratepayers and utilities around utility performance. The order also sets forth additional procedural criteria for the continuation of the Commission's investigation into grid modernization.

Information relative to this investigation, including docket filings, other than any information for which confidential treatment has been requested of or granted by the Commission, is available at https://puc.nh.gov/Regulatory/Docketbk/2015/15-296.html.

TABLE OF CONTENTS

I. NEED FOR REFORM AND PATH FORWARD

New England's energy landscape has changed dramatically in recent years. Restructured electricity markets have led to a regional generation profile that has lowered the cost of energy supply and reduced carbon emissions. While the region has seen energy costs and emissions decline, costs and rates associated with the transmission and distribution systems have continued to rise. That increase in rates is the result of a combination of limited sales growth, declining system productivity, and a century-old regulatory structure that encourages investment in capital assets and focuses on commodity sales rather than rewarding efficiency and performance.

At the same time, rapid technological advances are creating opportunities to enhance grid reliability and resilience, capture efficiencies, and improve customer services. The growth of distributed energy resources, including energy efficiency, demand response, distributed generation, electric vehicles, and energy storage, is changing how customers expect to interact with their utility. Advanced technologies have the potential to save customers money, reduce emissions, and enable flexible energy services.

In light of those trends, it is incumbent on the Commission to re-align the utility planning and investment process, as well as compensation methods, to ensure that customers of regulated utilities continue to receive safe, adequate, and reliable service at just and reasonable rates.

A more granular and transparent approach to distribution system planning is necessary to ensure that investments are prioritized in a manner that accommodates an evolving electric system, while also maximizing ratepayer value. That includes provision of circuit-level data when a foreseeable system need is identified, and meaningful consideration of alternatives to traditional capital investments when those alternatives may be capable of satisfying a grid need at least cost. Any investments and related functionalities should be traceable to the distribution planning objectives we outline in this guidance. *See* Staff Report Appendices B-E. The approach also anticipates stakeholder involvement, including the input of an independent professional engineer, into the utility-driven process of distribution system planning.

In the short term, we expect a modified approach to distribution system planning will facilitate and provide expertise concerning the evaluation, selection, and prioritization of investments in a manner that accommodates changing customer expectations while also minimizing customer bill impacts.

As part of the continued investigation into grid modernization, we direct stakeholders to examine metrics for measuring system performance consistent with the Commission's statutory mandate and the distribution system planning objectives set forth below. Once that process is complete, the Commission plans to open an investigation to explore the feasibility of adopting performance-based regulation as a means of better aligning customer and shareholder interests around utility performance.

II. PROCEDURAL HISTORY

On July 30, 2015, as directed by House Bill 614 (2015), the Commission opened Docket No. IR 15-296, to investigate the modernization of New Hampshire's electric grid. Given the breadth and complexity of the topic, the Commission invited all interested parties to participate in the proceeding and designated the electric distribution utilities mandatory parties.[2]

The Commission received comments on grid modernization in the summer and fall of 2015. Commission Staff (Staff) engaged Raab Associates Ltd. (Raab) to facilitate and mediate a working group process. Synapse Energy Economics provided analytical services to Commission

[2] The regulated electric distribution utilities include Public Service Company of New Hampshire, Inc. d/b/a Eversource Energy; Unitil Energy Systems, Inc. (Unitil); and Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty Utilities. The regulated electric distribution utilities are collectively referred to as the "Utilities."

Staff and the stakeholders. *See Investigation Into Grid Modernization*, Order No. 25,877 (April 1, 2016) (Order on Scope and Process).

Raab facilitated numerous stakeholder sessions and on March 2, 2017, filed a report with the Commission titled “Grid Modernization in New Hampshire” (Working Group Report). The Working Group Report included a number of policy issues and identified areas of consensus and areas of dispute among stakeholders, but made no recommendations on non-consensus issues.

Staff filed a report on February 12, 2019. Staff Recommendation on Grid Modernization (January 31, 2019) (Staff Report). The Staff Report incorporated the policy recommendations of the Working Group Report. Building on those recommendations, the Staff Report included a process and framework for utilities to develop an integrated distribution plan (IDP) that accommodates grid modernization. The Staff Report recommended that a number of issues be further refined by stakeholders through the working group process. The Staff Report was presented 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. Following the public comment hearing, the Commission scheduled another technical session for stakeholder discussions with respect to the process going forward. The technical session was held on May 15, and on May 17, the Office of the Consumer Advocate (OCA) filed additional comments.

On May 29, 2019, the Commission issued Order No. 26,254, in which it requested written comments on eleven topics and scheduled two additional technical sessions. The eleven topics included:

(1) Cost-Effectiveness Methodology;
(2) Utility Cost Recovery;
(3) Utility and Customer Data and Third Party Access;
(4) Hosting Capacity/Locational Value Analysis/Interconnection;
(5) Annual Reporting Requirements;
(6) Rate Design Policy;
(7) Strategic Electrification Policy;
(8) Consolidated Billing/General Billing;
(9) Consumer Advisory Council/Stakeholder Engagement;
(10) Capital Budgeting Process; and
(11) LCIRP/IDP Integration.

On July 26, 2019, the Commission issued Order No. 26,275, denying the OCA's request for rehearing of Order No. 26,254. Stakeholder comments were filed on September 6, and representatives of the following stakeholders met in two technical sessions held on September 19 and October 10: Clean Energy NH, Conservation Law Foundation (CLF), Eversource Energy, the Department of Environmental Services (DES), Direct Energy, the City of Lebanon, Liberty Utilities, Patricia Martin, the OCA, and Unitil. On October 31, Staff filed a Memorandum (Staff Memorandum) summarizing the results of the two technical sessions and identified issues where limited consensus is possible.[3] OCA filed a response to Staff's Memorandum on November 6 (OCA Response).

This guidance document and the modified approach to distribution system planning recommended by the Commission is the result of extensive collaboration and consensus building described above.

III. STAFF AND STAKEHOLDER COMMENTS

The positions conveyed in the February 2019 Staff Report, September 2019 Stakeholder Comments, and October 2019 Staff Memorandum, are described in the Commission Analysis

[3] References to areas of stakeholder agreement in the Staff Memorandum and our description of the memorandum do not include the OCA's agreement on a given subject matter.

section. Certain earlier comments are addressed by prior orders. *See Investigation Into Grid Modernization*, Order No. 25,877 (April 1, 2016) (Order on Scope and Process); Order No. 26,254 (April 29, 2019) (Order on Procedural Issues for Developing Requirements for Integrated Distribution System Plans).

IV. COMMISSION ANALYSIS

A. Commission Authority

The Commission has supervisory authority over public utilities in order to carry into effect the statutory provisions placed under the Commission's control by the Legislature. RSA 374:3. As part of its general oversight of electric distribution utilities, the Commission must determine whether the services utilities provide through their distribution networks are adequate for their customers' needs, and whether those services are provided at reasonable rates. RSA 374:1-:5 (Commission's General Oversight of Public Utilities); RSA 378:7 (Commission's duty to set just and reasonable rates).

Pursuant to House Bill 614, the Commission opened this investigation to explore whether the services offered by New Hampshire's electric distribution utilities require modification to accommodate recent technological advancements and shifting customer expectations while also maintaining safety and reliability at least cost. RSA 365:5 (Commission's Independent Investigation Authority). The Commission must review electric and gas utility distribution system planning to determine whether that planning meets the objectives of the developing energy resource mix in New Hampshire. RSA 378:37-:40 (Commission's authority to approve public utility planning processes).

When considering whether to allow a regulated utility to recover electric distribution system investment costs from ratepayers, the Commission must first determine whether those investments were prudently incurred. RSA 378:28 (Commission's authority to grant rate recovery of prudently incurred, used, and useful investments). In determining whether an investment was prudently incurred, and in making all other determinations, the Commission has a statutory obligation to balance the interests of ratepayers and utility investors. RSA 363:17-a. The Commission has discretion to adopt different procedural approaches or combinations of approaches in balancing ratepayer and investor interests. *Re Statewide Electric Utility Restructuring Plan*, Order No. 22,244, 81 NHPUC 564, 566 (1996) (stating "it is clear that not all administrative agency proceedings must be rigidly and categorically classified as either rulemaking or adjudication for the duration of the proceeding"); and citing C. Koch, *Administrative Law and Practice,* §2.14 (1985) (1996 Supplement) ("It has become black letter law that the choice to proceed by rulemaking or adjudication lies within the sound discretion of the agency.").

The principles set forth in this statutory framework have been the bedrock of least-cost distribution system planning in New Hampshire for decades, and absent statutory changes, will continue to be for the foreseeable future. The least-cost planning framework we adopt does not distinguish between grid modernization investments or business as usual investments.

Planning and investment decisions made today must account for the changing nature of our distribution system, including foreseeable technological evolution and changing customer expectations, or risk a determination that the investment was not prudent. Least-cost planning also requires that any investments accommodating the changing nature of the distribution system be adequately justified and made at the lowest reasonable cost.

B. Grid Modernization Objectives

"The Commission expects the benefits of grid modernization will include the following: [i]mproving the reliability, resiliency, and operational efficiency of the grid; [r]educing generation, transmission, and distribution costs; [e]mpowering customers to use electricity more efficiently and to lower their electricity bills; [and] [f]acilitating the integration of distributed energy resources." *See Investigation into Grid Modernization*, Order No. 25,877 at 2 (April 1, 2016).

The Commission also expects that any investments in grid modernization must result in net benefits for customers, meaning that the overall benefits of grid modernization initiatives must exceed the overall costs, all customers must have an opportunity to enjoy the benefits, and incremental costs must be equitably allocated among customers. *Id.* at 2-3.

We note those goals are consistent with the policy defined in RSA 378:37 and the energy strategy developed by the New Hampshire Office of Strategic Initiatives. *See* New Hampshire Office of Strategic Initiatives, New Hampshire 10-Year State Energy Strategy 13-14 (April 2018).

The Commission's Grid Modernization Working Group, and later Commission Staff, endorsed the expected benefits in their articulation of grid modernization objectives. Staff Report at 11, 93-94 (Appendix C), and 96-98 (Appendix D).

Based on the consensus benefits initially identified in the Working Group Report, Staff identified the following objectives for a modernized distribution system:

- Improve reliability, resiliency, and operational efficiency.
- Reduce generation, transmission, and distribution costs and increase affordability.
- Empower customers to use electricity more efficiently, lower electricity bills, and ensure access to usage data in readily accessible form, which can be made available to third parties while retaining privacy.
- Facilitate integration of DERs.
- Better align interests of energy consumers and producers to optimize system performance while enabling strategic electrification of buildings, homes, and vehicles.
- Keep New Hampshire technologically innovative, economically competitive, and in step with the region.
- Reduce environmental impacts and carbon emissions in New Hampshire.

Subject to the modification below, we adopt the Staff's objectives for the modern distribution system in New Hampshire and identify the statutory basis for each objective.

C. Modification to Electrification Objective

Providing the appropriate cost-based price signals to behind-the-meter load and generation can make more efficient use of our existing distribution system, thereby improving load factor and potentially lowering customer costs. Order No. 26,322 at 12-13 (December 30, 2019). It is our support for strategic electrification's potential to improve system load factor that leads us to make one clarification to Staff's proposed objective. Staff suggests that a modernized distribution planning process should *enable* strategic electrification. We clarify that a modern distribution planning process should instead *plan for* strategic electrification. As markets and technologies for electrified end uses evolve, it will be important to ensure those end uses are integrated onto the grid in a manner that does not unreasonably burden non-participating ratepayers through peak load growth.

D. Statutory Support for Grid Modernization Objectives

We find the statutory authority for Staff's proposed grid modernization objectives within the least-cost planning statute, the restructuring statute, the electric renewable portfolio standard statute, the limited electrical energy producers statute, the energy data platform statute, and the multiple pollutant reduction program statute.

1. <u>Improve Reliability, Resiliency, and Operational Efficiency</u>

The least-cost planning and restructuring statutes support an emphasis on improved reliability, resiliency, and operational efficiency. The least-cost planning statute requires that LCIRPs include "an assessment of distribution and transmission requirements, including an assessment of the benefits and costs of 'smart grid' technologies, and the institution of electric utility programs designed to ensure a more reliable and resilient grid to prevent or minimize power outages." RSA 378:38. RSA 378:38 places explicit emphasis on reliability and resiliency. In addition the provision of RSA 378:38 requiring an assessment of smart grid technologies provides support for operational efficiency improvements, because a primary benefit of smart grid technologies is to improve operational efficiency through reduced operating costs and improved asset optimization. Staff Report at 101. The restructuring statutes also place extensive emphasis on the provision of safe and reliable service. RSA 374-F:1-:4. Based on that statutory support, we adopt the proposed emphasis on reliability, resiliency, and operational efficiency improvement as an objective of the modern distribution system.

2. <u>Reduce Generation, Transmission, and Distribution Costs, and Increase Affordability</u>

The least-cost planning and restructuring statutes support an emphasis on affordability improvements that result from reducing generation, transmission, and distribution costs. The least-cost planning statute declares that "it shall be the energy policy of this state to meet the energy needs of the citizens and businesses of the state at the lowest reasonable cost." RSA 378:37. The restructuring statute allows funding of targeted conservation, energy efficiency, and load management programs if those strategies are intended to reduce distribution costs. It also allows utility ownership of small scale distributed generation if part of a strategy to minimize transmission and distribution costs. RSA 374-F:3, III; RSA 374-F:4, VII, (e); *see* also, RSA 374-G:2, I, (b). Based on that statutory support, we adopt the proposed emphasis on affordability improvements that result from reducing generation, transmission, and distribution costs as an objective of the modern distribution system.

3. Empower Customers to Use Electricity More Efficiently

The least-cost planning, restructuring, energy data platform, and customer data privacy statutes support an emphasis on energy data access and privacy. The least-cost planning statute declares it the energy policy of the state to "maximize the use of cost-effective energy efficiency and other demand side resources." RSA 378:37. Streamlining customer access to energy usage data has the potential to stimulate a market for services related to energy efficiency and other demand side resources in support of that policy. For example, the restructuring statute identifies cost reductions associated with competitive markets as the most compelling reason to restructure, and suggests that development of competitive markets for retail electricity service is a key component of restructuring. RSA 374-F:1. In enacting the multi-use energy data platform statute, the Legislature found that "[a]ccess to granular energy data is a foundational element for moving New Hampshire's electric and natural gas systems to a more efficient paradigm," and that "the state can open the door to innovative business applications that will save customers money, allow them to make better and more creative use of the electricity grid."[4] 2019 N.H. Laws, ch. 286 (SB 284). The energy data platform statute also requires administration of the

[4] Our reference to the energy data platform statute in justifying this objective should not be interpreted as an endorsement of the energy data platform itself. RSA 378:51, III directs the Commission to "defer the implementation of the statewide, multi-use, online energy data platform… if it determines that the cost of such platform to be recovered from customers is unreasonable and not in the public interest." Any such determination must be based on an examination of whether the costs of such a platform are reasonable and in the public interest, in light of any related benefits.

platform in a manner consistent with RSA 363:38, which describes the duties and responsibilities of energy service providers who may access customer usage data, including privacy protections by which providers must abide. RSA 378:52, III. Based on that statutory support, we adopt the proposed emphasis on customer empowerment through energy data access while maintaining privacy as an objective of the modern distribution system.

4. Facilitate Integration of DERs

The least-cost planning, restructuring, limited electrical energy producer, and electric renewable portfolio statutes support an emphasis on facilitating integration of DERs. The least-cost planning statute declares it the energy policy of the state to maximize the use of energy efficiency and demand side resources, requires LCIRPs to include an assessment of supply options including distributed energy resources. That statute also directs the Commission to prioritize energy efficiency and other demand side resources when proposed options have equivalent cost, reliability, environmental, economic, and health-related impacts. RSA 378:37-:40. As noted above, the restructuring statute allows utility ownership of small scale distributed generation if part of a strategy to minimize transmission and distribution costs. RSA 374-F:3, III; RSA 374-G:2, I, (b). The limited electrical energy producers statute declares it "in the public interest to provide for small scale and diversified sources of supplemental electric power," and describes net metering as a means of providing "a reasonable opportunity for small customers to choose interconnected self-generation, encourage private investment in renewable energy resources, stimulate in-state commercialization of innovative and beneficial new technology, enhance the future diversification of the state's energy resource mix, and reduce interconnection and administrative costs." RSA 362-A:1. The renewable portfolio standard statute states it is "in the public interest to stimulate investment in low emission renewable energy generation technologies in New England and, in particular, New Hampshire." It also describes numerous benefits of renewable energy generation technologies, including fuel diversity; reducing exposure to fossil fuel price volatility; keeping investment dollars in state; improving air quality and public health; and mitigating against risks of climate change. RSA 362-F:1. Based on that statutory support, we adopt the proposed emphasis on facilitating integration of distributed energy resources as an objective of the modern distribution system.

5. *Optimize System Performance and Plan for Strategic Electrification*

The least-cost planning and restructuring statutes support an emphasis on better aligning the interests of energy consumers and producers while planning for strategic electrification of buildings, homes, and vehicles. The prioritization in the least-cost planning statute of "energy efficiency and other demand-side management resources," when evaluating options presented in a utility's least-cost integrated resource plan, supports the above-described objective, particularly when viewed in the context of the Commission's recent support for load factor improvement opportunities. RSA 378:37-:40; *see* also, Order No. 26,322 at 12-13 (December 30, 2019). The restructuring statute describes a primary purpose of restructuring as providing "electricity suppliers with incentives to operate efficiently and cleanly, open markets for new and improved technologies, [and] provid[ing] electricity buyers and sellers with appropriate price signals." RSA 374-F:1. That description of the relationship between energy consumers and producers stands true not just for supply-side resources, but also for demand-side resources such as dispatchable load or distributed generation. Based on that statutory support, we adopt, with the modification detailed above,[5] the proposed emphasis on optimizing system performance and planning for strategic electrification as an objective of the modern distribution system.

[5] We clarified above that a modern distribution planning process should *plan for* rather than *enable* strategic electrification.

6. *Remain Technologically Innovative, Economically Competitive Within the Region*

The least-cost planning and restructuring statutes support an emphasis on keeping New Hampshire technologically innovative, economically competitive, and in step with the region. The least-cost planning statute requires the Commission to consider the economic impacts of options presented in an LCIRP; one possible economic impact associated with an option is the effect on the New Hampshire economy relative to the rest of the region. RSA 378:39. The restructuring statute establishes a non-bypassable and competitively neutral system benefits charge that may fund "support for research and development, and investments in commercialization strategies for new and beneficial technologies." RSA 374-F:3. Based on that statutory support, we adopt the proposed emphasis on keeping New Hampshire technologically innovative, economically competitive, and in step with the region as an objective of the modern distribution system.

7. *Reduce Environmental Impacts and Emissions in New Hampshire*

The least-cost planning, restructuring, and multiple pollutant reduction program statutes support an emphasis on reducing environmental impacts and emissions in New Hampshire. The least-cost planning statute declares it the energy policy of the state to "meet the energy needs of the citizens and businesses of the state at the lowest reasonable cost while … protect[ing] the safety and health of the citizens, the physical environment of the state, and the future supplies of resources." It also requires LCIRPs to contain "an assessment of the plan's long- and short-term environmental … impact on the state," and requires the Commission to "consider potential environmental, economic, and health-related impacts," of options within an LCIRP. RSA 378:39-:40. The restructuring statute directs that "environmental protection and long term environmental sustainability should be encouraged." RSA 374-F:3, VII.

In enacting the multiple pollutant reduction program statute, the General Court found that "adequate protection of public health, environmental quality, and economic well-being … requires additional, concerted reductions in air pollutant emissions." In addition, the General Court found that "reducing air pollutant emissions returns substantial economic benefit to the state." RSA 125-O:1. The renewable portfolio standard statute states "it is in the public interest to stimulate investment in low emission renewable energy generation technologies in New England and, in particular, New Hampshire." That statute also suggests that "employing low emission forms of such technologies can reduce the amount of greenhouse gases, nitrogen oxides, and particulate matter emissions transported into New Hampshire and also generated in the state, thereby improving air quality and public health, and mitigating against the risks of climate change." RSA 362-F:1. Based on that statutory support, we adopt the proposed emphasis on reducing environmental impacts and emissions in New Hampshire as an objective of the modern distribution system.[6]

E. Topical Guidance

At the technical session held on May 15, 2019, the parties agreed to file comments on 11 topics contained in the Staff Report. Order No. 26,254 at 4.[7] The Commission summarizes party positions relating to, and provides its guidance on, those eleven topics below.

---

[6] We note that value of avoided costs associated with environmental impacts is under consideration in other dockets before the Commission and this order should be interpreted as encouraging consistency among dockets, rather than endorsing any specific avoided cost value for environmental impacts.

[7] Parties agreed to combine the topics of locational value and hosting capacity with a discussion of interconnection, forego individualized categories for comments relating to metering, DER pricing structure, and cybersecurity, and add a comment category related to a proposed consumer advisory council/stakeholder engagement. The topic of cybersecurity remains an important consideration for the Commission. We expect the Utilities will continue to work with the Commission to ensure vital systems remain safe and secure from cyber threats.

(1) Integration with Least-Cost Integrated Resource Planning

i. Staff Report

The Staff Report recommended the current LCIRP process be updated to include additional grid modernization investments for a more integrated and transparent planning process. Staff Report at 20-22. Staff suggested that planning for grid modernization should not be separate from least-cost integrated resource planning, because business as usual and grid modernization investments are interdependent. *Id*. Staff also proposed an outline of the subject matter that should be covered in, what Staff referred to as, an "integrated distribution plan."[8] *Id*. at 68-71.

ii. Utilities

The Utilities filed joint comments. They supported the transition from the LCIRP to a more comprehensive and holistic IDP. The Utilities agreed with the IDP components recommended in the Staff Report, however, they also provided a proposed IDP outline of their own. Joint Utility (JU) Comments at 18-22.

iii. OCA

The OCA praised certain features of the existing LCIRP process, including the transparency and stakeholder engagement embedded within LCIRP filing and adjudication requirements. The OCA suggested the IDPs and IDP approval process could build upon this by: (1) placing further emphasis on transparency and stakeholder engagement; (2) serving as the determinant of forward-looking capital budgets, subject to some degree of flexibility, rather than being developed for informational purposes only; and (3) employing a single planning and

---

[8] Consistent with the naming convention in the Staff Recommendation and Stakeholder comments, we refer to an Integrated Distribution Plan throughout our description of positions taken within those documents. However, as described further in the guidance below, we decline to adopt that naming convention.

budgeting process regardless of whether an investment is defined as a traditional investment or a grid modernization investment. OCA Testimony of Paul J. Alvarez and Dennis Stephens at 17-18 (September 6, 2019) (OCA Comments).

iv. CLF

CLF commented extensively on the integration of grid modernization planning with existing distribution planning. CLF suggested that the first steps of implementing grid modernization should be to obtain an accurate assessment of the current capabilities of the distribution system and develop a full understanding of the current distribution planning process used by the utilities. CLF emphasized that the distribution planning process should be clear and transparent. CLF Comments (September 6, 2019).

v. Clean Energy NH

Clean Energy NH did not discuss IDP/LCIRP integration in its comments.

vi. DES

DES did not discuss IDP/LCIRP integration in its comments.

vii. Commission Guidance

The Staff Memorandum observed agreement among stakeholders that the LCIRP should be combined with the IDP, but noted disagreement regarding IDP filing frequency. Staff Memorandum at 5. We agree that grid modernization planning is a natural evolution of the LCIRP process and that the LCIRP statutes should be viewed as the foundation upon which grid modernization planning will be built. We do not, however, see the need to adopt the "IDP" naming convention proposed in the Staff Report and adopted by the commenters. Instead, we will continue to refer to LCIRPs that include grid modernization planning as LCIRPs, rather than IDPs. As the Commission expressed in its Order on Scope and Process, "grid modernization planning will build off of the electric utilities' existing practices for making investment decisions regarding the maintenance, operations, and upgrades to their distribution systems … fit[ting] naturally within the utilities' existing integrated resource planning." Order No. 25,877 at 4 (April 1, 2016).

LCIRPs, Generally. Upon review of the stakeholder comments and Staff Report, we find that for future LCIRPs the following would create consistency and efficacy: (1) filing on a staggered basis by each electric distribution utility every three years;[9] (2) inclusion of a granular load forecast, DER forecast, and detailed description of foreseeable distribution system needs over the next five years, including five-year capital and operating expenditure plans; (3) a comparison of solutions to meet those needs and potential alternatives, including non-wire solutions where appropriate; (4) a description of foreseeable system investments planned for the next 10 years; and (5) a summary of stakeholder input, how stakeholder recommendations are incorporated into the final plan, or why a stakeholder recommendation was not incorporated into the final plan.[10] These general guidelines may evolve over time as customer expectations and distribution system needs evolve.

Pre-Approval and Pre-Authorization. The Working Group Report suggests that initiatives proposed within a grid modernization plan would "require pre-authorization by the Commission." The Working Group Report also suggests that any pre-authorized investments are "presumed to be prudent, in terms of the decision to proceed with them," but during reconciliation a utility must "demonstrate that the actual costs incurred are reasonable."

---

[9] Consistent with the timeline required under RSA 378:38, and assuming each Company's near-term LCIRP will require approximately one year of docket processes prior to a final order, Unitil, Eversource, and Liberty's subsequent LCIRPs would be filed during April 2023, September 2023, and January 2024, respectively. Actual LCIRP filing dates beyond 2021 will be determined by subsequent Commission orders.

[10] Statutory requirements not required by the enumerated guidelines may be waived under RSA 378:38-a.

Working Group Report at 30. The Staff Report and Utility comments also suggest that the LCIRP should serve as a vehicle for the Commission to pre-authorize those investments and actions proposed in the LCIRP. Staff Report at 63, 64, and 76; JU Comments at 7. The LCIRP statute states that "Commission approval of a utility's [LCIRP] shall not be deemed a pre-approval of any actions taken or proposed by the utility in implementing the plan." RSA 378:39.

We reiterate that approval of an LCIRP will not be considered pre-approval of an investment decision. It is merely an expression by the Commission that, based on the facts provided within the LCIRP process, a decision to proceed with the types of investments in the LCIRP appears reasonable on its face.

As proposed by Staff and the Commenters, the LCIRPs will cover a period of ten years, with specific investment decisions contemplated as far as five years into the future. Even with new LCIRPs filed every three years, markets and technologies have the potential to change significantly between filings. Utility decision makers are obligated to continually examine changed circumstances which may render an investment imprudent prior to its undertaking or completion. Notwithstanding approval of an LCIRP, a utility's actions must be prudent and reasonable at the time each action is taken to ensure cost recovery, and any investment proposed in an LCIRP shall be subject to the same scrutiny and potential disallowances as any other investment at the time it is sought for inclusion in rates. We expect, however, that barring changed circumstances, or imprudent project management or deployment, the stakeholder-involved process used to inform and prioritize investment decisions will help reduce the risk that investment decisions are later found to be imprudent.

Unitil LCIRP Example. We note that the most recently approved LCIRPs are not uniform in the level of detail they provide regarding company planning and budgeting processes, operating procedures, equipment standards, planning criteria, load forecasts, future system needs, planned solutions, and potential alternatives to planned solutions. We find that the level of detail offered with respect to those items in Unitil's 2016 LCIRP and associated Appendices is the minimum template and substance for what utilities should provide in any future LCIRPs, as supplemented by this guidance and Commission orders. *See Unitil Energy Systems 2016 LCIRP* and *Appendices* filed on April 19, 2016, in Docket No. DE 16-463; *see also, Unitil Energy Systems, Inc.* Order No. 26,098 at 8 (January 9, 2018) (requiring more evidence regarding cost comparisons of the alternatives considered, reliability, environmental, economic, and health-related impacts for Commission evaluation under RSA 378:39).

2020/21 LCIRPs. In Order Nos. 26,261 and 26,262, the Commission granted requests from Eversource and Liberty to waive the provision in the LCIRP statute that requires each utility to file an LCIRP within two years of an order approving the utility's most recent LCIRP, and allowed both to make more limited filings in place of their full 2019 LCIRPs. Notably, the Commission did not waive the requirement that Eversource and Liberty file a full LCIRP within five years of the most recent LCIRP filing.

To meet the five-year filing requirement, Unitil filed its 2020 LCIRP in April, and Eversource and Liberty are required to file their LCIRPs in June 2020 and January 2021, respectively. We recognize that the enhanced process for LCIRP development and project prioritization described in this order may not be complete by the time each utility is required to file its next LCIRP. We clarify that those near-term LCIRPs must provide at least a baseline level of detail and transparency regarding distribution system planning, consistent with the level of detail provided by Unitil in its 2016 LCIRP filing as discussed above.

We expect near-term LCIRPs to focus primarily on non-discretionary investments needed to maintain safe and reliable service. We do not expect LCIRPs filed before the second quarter of 2021 to incorporate the enhanced planning processes further described in this guidance to prioritize discretionary investments that may provide a net benefit to ratepayers.

LCIRP Adjudication and Stakeholder Process. The OCA and other parties have at times during this docket highlighted the value of adjudicatory processes, going so far as to suggest that "the only avenue available to the Commission for developing such a framework, in a manner that is both binding and compliant with the least-cost integrated resource planning statute, is adjudication pursuant to RSA 541-A:31." Motion for Rehearing of Clarification filed by the Office of the Consumer Advocate, *et al*. June 27, 2019, at 17. Although RSA 378:39 requires the Commission to review individual utility LCIRPs in an adjudicative proceeding, we believe there is benefit in undertaking a clearly defined stakeholder process that allows meaningful opportunities for input on decisions affecting utility planning and related investments before adjudication commences.

We emphasize, as we did in approving the Benefit Cost Working Group recommendations, that "constructive stakeholder processes can aid the Commission in its decision-making duties and allow parties to reach a result in line with their expectations." Order No. 26,322 at 8 (December 30, 2019). Even in cases where no consensus is reached during up-front collaborative processes, we expect those processes will streamline litigation by identifying non-consensus issues and the positions of the parties relative to those issues prior to adjudication. Indeed, we believe the time that stakeholders invest in collaboration and consensus will lead to more uniform, more transparent, and more successful modernization of the grid and will have the benefit of reducing the amount of litigation necessary to review and approve individual utility LCIRPs. This is so, even if, and perhaps because, aspects of the LCIRP process will at least begin as a product of agreement rather than contention or regulatory requirement.

LCIRP Template. The Staff and the Utilities both provided an outline describing the LCIRP subject matter, with Staff's outline containing a greater level of detail than the Utilities' outline. Staff Report at 68-71; JU Comments at 21-22. We prefer the level of detail and subject matter set forth in Staff's LCIRP outline. While we decline to require a specific LCIRP outline at this time, we recommend the Utilities consider Staff's outline as a starting point for stakeholder discussions related to future LCIRP development.

Rate Case – LCIRP Alignment. We value a transparent utility planning process that identifies likely investments in advance of a given need. We expect the analysis developed to prioritize investments proposed in the LCIRP and related annual filings will be of value to the Commission, the Utilities, and other stakeholders when a utility requests recovery of those investments. The LCIRP and related annual filings may align well with rate case filings and any requested step increases, and we expect each utility to weigh the potential synergies of the related rate case and LCIRP filings when planning for rate changes. Our expectation is that investments for which recovery is requested in rate cases are consistent with investments described in the LCIRP and related filings.

(2) Utility Cost Recovery

i. Staff Report

For the purpose of cost recovery, the Staff Report distinguished between grid modernization investments and business as usual investments. Staff Report at 22, 63. For grid modernization investments, Staff proposed the Commission "provide preliminary approval of grid mod investments based on cost [recovery] analysis and subject to subsequent verification for prudency." *Id*. Under Staff's proposal, the Commission would consider how prudently the Company managed a project, but not the decision to undertake the project, in an annual reconciliation docket. *Id.* at 64. Staff said preliminary approval would be consistent with a targeted cost recovery mechanism, colloquially referred to as a tracker, meant to enable recovery of capital and operation and maintenance (O&M) costs on an annual basis for a period of no more than five years. *Id.*

Staff also recommended a charge be established for recovery of sunk costs that become stranded when existing plant is "replaced prematurely in order to accelerate the timeline for a more technology-driven grid." *Id*. at 63. As proposed by Staff, the costs of grid modernization investments and any stranded assets that result would be recovered via volumetric charges only. *Id*. at 64. Staff recommended revenue decoupling in each utility's next rate case "to remove potential disincentives in grid modernization investments." *Id*. at 63. Staff also suggested that "performance-based regulation and performance metrics … should be proposed as a way to replace existing traditional regulatory measures," recommending that stay-out provisions and multi-year rate plans approved in recent electric distribution rate cases continue. *Id*.

ii. Utilities

The Utilities supported Staff's proposed targeted cost recovery mechanism to recover costs related to grid modernization outside of base rates and traditional rate case processes. JU Comments at 6-7. The Utilities asserted that grid modernization investments eligible for recovery via the tracker would need to be pre-authorized within the IDP docket or other standalone dockets. *Id*. Pre-authorization, according to the Utilities, would include a presumption of prudence, but would be "subject to reconciliation based on actual costs and appropriate supporting documentation." *Id*. at 7.

iii. OCA

The OCA asserted that the Utilities recover investments identified in their IDPs through rate cases, which the OCA described as an opportunity to "reconcile the capital an [investor-owned utility] IOU actually spent to the capital budgets approved as part of a distribution plan." OCA Comments at 54-55. The OCA argued there is no justification for accelerated cost recovery for grid modernization investments. The OCA suggested that distributed energy resource (DER) penetration in New Hampshire is "at least a decade behind" states where high DER penetration levels have necessitated accelerated recovery of investments required to accommodate high DER penetration. *Id*. at 60-61. The OCA agreed with the observation that there may be opportunities to alter the utility business model in a manner that might minimize or remove the throughput incentive and capital bias inherent in cost-of-service ratemaking. OCA Response at 3, citing Staff Memorandum at 5, fn. 8.

iv. CLF

CLF did not discuss cost recovery in its comments.

v. Clean Energy NH

Clean Energy NH suggested a need for new regulatory models to "better fit the needs of the utilities of the future and as a result of customers' expectations of the services delivered and made possible by a modern utility and grid." Clean Energy NH Comments dated September 6, 2019, at 3. Clean Energy NH expressed support for decoupling as a means to address the throughput incentive, and performance-based regulation as a means to reduce other undesirable incentives that may serve as an impediment to the goals of grid modernization. *Id.*

vi. DES

DES suggested that docket processes to date, have not sufficiently examined utility business model reforms that might "incentivize/compensate the deployment of DERs and demand management rather than traditional utility infrastructure." DES, however, voiced skepticism as to what reforms might be made.[11] DES Comments dated November 14, 2019, at 1-2.

vii. Commission Guidance

Business as Usual v. Grid Modernization Investments. We find that a utility that is not engaged in modernization of both its capital assets and its operations would be imprudent, as would any other company neglecting to modernize. That said, it does not follow that all utility grid modernization is inevitably prudent. The LCIRP framework described in this guidance does not distinguish between grid modernization investments or business as usual investments. In New Hampshire, the slow but steady embrace of grid modernizing technologies such as distribution automation and advanced metering infrastructure has been ongoing for several years, with cost recovery often granted through the normal course of distribution rate cases. Working Group Report at 34-42. In other jurisdictions, distribution automation and advanced metering infrastructure are significant components of initial grid modernization investment plans. Based on the reasoning above, we expect that LCIRPs will not differentiate between grid modernization investments and traditional utility distribution system investments.

Targeted Cost Recovery Mechanism. We are not convinced that a targeted cost recovery mechanism is warranted in New Hampshire at this time. Instead, we believe that investments described in an LCIRP should generally be recovered in the normal course of distribution rate

[11] DES's comments were received by the Commission on November 18, 2019. These comments reiterated footnotes contained in the Staff Memorandum. While the comments were not filed during the public comment solicitation period, they were considered for the purpose of our analysis.

proceedings. The Staff Report suggested that the multi-year rate plans and stay-out provisions included in the most recent electric distribution rate cases should continue. Staff Report at 63. We clarify that the multi-year planning processes envisioned for future LCIRPs share some characteristics of the previously granted rate case step increases; and we therefore accept that, in some cases, annual cost recovery of capital investments may be warranted. In exchange for the opportunity to continue recovery of certain capital costs through annual step increases, we expect future LCIRPs will provide a greater degree of transparency and opportunity for stakeholder input on a utility's planned investments than was previously available.

Stranded Assets. Both Staff and the Utilities suggested that a targeted cost recovery mechanism should recover costs associated with assets that may no longer be used and useful as a result of planned grid modernization investments. Staff Report at 64; JU Comments at 6-7. The Commission is precluded by statute from including in permanent rates "any return on any plant, equipment, or capital improvement which has not first been found by the Commission to be prudent, used, and useful." RSA 378:28. We do not expect that utilities will choose to replace prudently incurred, undepreciated assets as part of a future LCIRP. If a utility so chooses, however, we will address the recovery of undepreciated amounts at the time the utility seeks to place its new investment into rate base. We will not, therefore, establish a targeted cost recovery mechanism in this proceeding.

Decoupling. Staff and Clean Energy NH supported decoupling as a means of encouraging initial utility business model reforms and removing the throughput incentive and potential disincentives for utilities to invest in grid modernization.[12] Staff Report at 63, Clean

[12] Under cost of service regulation, a utility's revenue requirement is generally set based on the costs that occur during a test year that is the focus of a rate case. In actuality, those costs vary between test years based on a number of factors, including the economy, weather, utility spending on capital assets and operating expenses, and investments in energy efficiency. Decoupling (also known as "revenue regulation") fixes the amount of revenue to

Energy NH Comments at 3. The Utilities are required to file for decoupling in their next rate case after December 31, 2020. *See* Order No. 25,932 at 30, 60 (August 2, 2016).

Cost Recovery and Performance-Based Regulation. Utility business model reform was discussed extensively in the Commission's Order on Scope and Process. *See* Order No. 25,877 at 8-10. The electric utility restructuring statutes also suggest that "[p]erformance-based or incentive regulation should be considered for transmission and distribution services." RSA 374-F:3, III. State regulators are increasingly looking to reform the cost-of-service regulation model that works well during times of high load growth, but faces challenges when load is flat or declining and is not well suited to encourage utilities to embrace competitive resources. Performance-based compensation structures have been an important component of driving success in New Hampshire's energy efficiency programs for several years.[13]

We recognize the value in regulatory constructs that may better align ratepayer interests and shareholder interests. At this time, we do not believe the LCIRPs are the appropriate place for the Commission to examine utility business model reform and opportunities for related performance metrics that impact utility compensation structures. A modernized approach to distribution system planning that provides for stakeholder involvement and review of planned investments — and metrics associated with those investments — may help lay the groundwork for performance-based regulation. Many examples of such a model exist, including multi-year rate plans, performance incentive mechanisms based on shared savings or a percentage of

---

be collected by a utility between rate cases and allows the price charged to float up or down to compensate for variations in sales volume, maintaining the set revenue level. The purpose is to allow utilities to recover allowed costs in volumetric prices, independent of sales volumes.

[13] *See generally* New Hampshire Performance Incentive Working Group. New Hampshire Energy Efficiency Calculation of Performance Incentive Beginning in 2020. (July 31, 2019). Available at: https://www.puc.nh.gov/EESE%20Board/EERS_WG/20190913-EERS-WG-PI-FINAL-REPORT.pdf.

specific investment's spending/budget, fully forecasted test years, and formulaic rates. Several states have recently opened proceedings examining opportunities for performance-based ratemaking.[14] We believe such a proceeding may be warranted in New Hampshire once the foundational elements of enhanced least-cost planning described in this guidance have been fully embraced. We remain willing, however, to consider performance incentive mechanisms that are narrowly tailored to a specific investment prior to that more comprehensive proceeding, as long as the incremental costs of such a mechanism are adequately justified.

(3) Hosting Capacity/Locational Value Analysis/Interconnection

i. Staff Report

The Staff Report observed that, in order to analyze hosting capacity, utilities must first provide information relating to current geographic information systems, system data, visibility, and capabilities. In providing that data, Staff recommended the utilities, with input from a stakeholder group, adopt a common approach, methodology, modeling tools, and assumptions. Subsequently, a Hosting Capacity Analysis (HCA) would be developed in phases, beginning with red, yellow, and green circuit maps described in the Working Group Report, but eventually evolve to include heat maps with sub-circuit thermal loading, indicating locational value and potential for non-wire solutions to displace traditional utility infrastructure needs. Staff Report at 56-58 (citing Working Group Report at 24-25).

Staff described locational net benefit analysis, referred to as constraint relief analysis in the Working Group Report, as a key component of the IDPs. Locational net benefit analysis would identify locations on the distribution system where "non-utility solutions to capacity

[14] *See generally*, District of Columbia Public Service Commission, Formal Case No. 1156, Order No. 20,273 at pages 21-28. https://edocket.dcpsc.org/apis/api/filing/download?attachId=89306&guidFileName=91813b51-4d10-4868-8a01-d87138e23adc.pdf.

requirements due to substation or distribution asset loading or reliability requirements could be utilized." *Id*. at 59. According to Staff, procurement of non-utility, or non-wire solutions would require development of detailed data relating to "load shape by time of day and month, circuit capacity, and reliability deficiencies due to capacity needs," as well as the ability to forecast identified needs with a lead time of 2-3 years. *Id.* at 59-60.

Staff recommended that IDPs should provide a detailed description of each type of analysis conducted by the utility for the purpose of satisfying interconnection applications, and that any proposed interconnection-related investments should improve DER developer interaction, transparency of system data, and limit interconnection queue waiting time. *Id*. at 73. Staff also recommended that in four to five years, an interconnection portal may be established so that the interconnection process may be streamlined. *Id*. at 39.

ii. Utilities

The Utilities agreed with Staff's phased approach to HCA, where interim goals incrementally expand capabilities over time. JU Comments at 9. To accommodate stakeholder feedback and collaboration regarding hosting capacity analysis and mapping, the Utilities proposed establishment of a standing technical committee on DER integration. *Id* at 10. The technical committee would be comprised of stakeholders and "would meet on a regular basis to review and discuss utility proposals related to HCA and calculation methodology, hosting capacity map design, [and] other technical issues related to DER interconnection." *Id*.

The Utilities suggested that, like HCA, locational value analysis will also require a phased approach. *Id*. They asserted that the policy mechanisms that will determine how an identified locational value is captured and shared should be understood in "advance of moving forward with any publicly available locational value analysis data," and suggested that demonstration projects may be a means of supporting that policy development. *Id*. at 11.

The Utilities recommended that issues related to interconnection should also be addressed by the proposed standing technical committee on DER integration, rather than within the grid modernization proceeding, because a standing technical committee would enable continued discussion of issues that come up over time as penetration of DER increases in New Hampshire. *Id*.

iii. OCA

The OCA asserted that circuit-specific, five-year probabilistic load and DG forecasts should form the basis for hosting capacity and locational value analysis. The OCA emphasized that inputs, constraints, and assumptions within the forecast should undergo rigorous stakeholder review. OCA Comments at 27-30. The OCA suggested that such analysis would facilitate strategies, tactics, and/or investments to prepare for high levels of DG penetration as such levels are approached on a circuit-specific basis, rather than system-wide. *Id.* at 28, 60.

iv. CLF

CLF recommended use of the most recent IEEE 1547 interconnection standard, which allows greater use of interconnected photovoltaics (PV). CLF Comments at 14. CLF also suggested a fast-track interconnection process for smaller resources and a more transparent interconnection process generally. *Id.* CLF recommended that the Commission prioritize updating the current interconnection process, rather than following Staff's recommended four- to five-year timeline. *Id.* With respect to any working group that might discuss hosting capacity, interconnection, or locational value, CLF suggested that the working group do more than receive information from the utilities. Staff Memorandum at 3.

v. Clean Energy NH

Clean Energy NH supported a standing working group on hosting capacity, locational value, and interconnection, and believes that hosting capacity information needs to be developed and interconnection processes need to be standardized, with a goal of avoiding interconnection backlogs and unreasonable wait times and costs. Clean Energy NH Comments at 1-2. Clean Energy NH identified the proposed working group as an appropriate venue for developing tiered interconnection queues and developing a shared cost approach to multiple DER projects proposing to connect in close proximity. Staff Memorandum at 3, n 2.

vi. DES

DES did not discuss hosting capacity, locational value analysis, or interconnection in its comments.

vii. Commission Guidance

Staff observed that stakeholders agreed to the creation of a standing working group prior to LCIRP filing for the purpose of reviewing "information on each utility's progress on hosting capacity analysis and presentation, locational valuation initiatives, and interconnection procedures." *Id.* at 3. Stakeholders also agreed that there may be synergies between the Locational Value of Distributed Generation Study underway in Docket No. DE 16-576, *Development of New Alternative Net Metering Tariffs and/or other Regulatory Mechanisms and Tariffs for Customer-Generators*, and the locational value analysis envisioned in the Staff Grid Modernization Report. *Id*. We agree with the stakeholder consensus and provide further guidance below.

Grid Modernization Stakeholder Group. We agree with the commenters that a stakeholder group should be established to make recommendations to the Commission with respect to issues discussed below. However, we do not limit the charge of that working group to just those issues. Instead, that group will guide the distribution system planning process more broadly. We recognize that there may be an incremental time commitment and related cost associated with a stakeholder group that plays a role in distribution system planning. Nonetheless, a more inclusive and collaborative planning process that takes place before a utility commits internally to making an investment will likely benefit ratepayers.

An up-front collaborative planning process will: (1) reduce litigation costs during the LCIRP adjudication; (2) help ensure that planned investments are the optimal use of finite ratepayer dollars; and (3) mitigate the need for and significance of costly litigation over cost recovery after an investment has been made. A direct analogue exists within the planning process for New Hampshire's ratepayer-funded energy efficiency programs, where the Commission has embraced collaborative processes that occur long before the litigation schedule with the aim of enabling stakeholders to resolve contested issues prior to plan filing and a contested case. In short, an up-front collaborative planning process is an investment in avoiding back-end litigation costs and optimizing investment choices.[15]

Accordingly, we establish a Grid Modernization Stakeholder Group (GMSG) that will be chaired by Commission Staff. It will aim to meet at least monthly for the first two years and then transition to bi-monthly once the initial LCIRP structures and substance are agreed upon. Staff shall collaborate with the Utilities and other stakeholders to determine meeting agendas.

[15] Order No. 26,095 at 2 (January 2, 2018) (Stating "The Three Year Plan was developed in consultation and collaboration with a variety of stakeholders, including, the Energy Efficiency and Sustainable Energy ("EESE") Board."); Order No. 26,322 at 8 (December 30, 2019) (Stating "constructive stakeholder processes can aid the Commission in its decision-making duties and allow parties to reach a result in line with their expectations.").

The GMSG is instructed to file a report within one year. The report should recommend actions related to the issues discussed directly below, as well as any proposed topics of further inquiry. We do not expect that the GMSG will provide input on the near-term LCIRPs or their development. The responsibilities of the GMSG are detailed throughout this document and summarized in Appendix A.

Hosting Capacity Analysis. Hosting capacity analysis informs developers about the amount of distributed energy resources that can be accommodated in a particular area without requiring upgrades to the existing infrastructure. We find that hosting capacity analysis should evolve over time and that the earliest versions of a hosting capacity analysis may be limited to a color-coded map of distributed generation hosting capability by circuit, with future versions resembling an online data portal. Some distribution utilities in the region, including Eversource in Connecticut, and National Grid in Rhode Island, already offer online DG hosting capacity maps.[16] In fact, National Grid's Rhode Island System Data Portal provides a single interface where a user can access a hosting capacity map, non-wire alternative candidate solicitations, a heat map detailing the thermal loading of electric distribution circuits, area planning studies, and load forecasts.

The level of transparency embodied in Eversource's Connecticut and National Grid's Rhode Island models may prove beneficial to New Hampshire ratepayers, and we direct the GMSG to examine those applications for relevant information and best practices. The review should include, but not be limited to inputs, thresholds, and costs that may be associated with such applications in New Hampshire. We decline to prescribe how often the hosting capacity

[16] *See* Eversource Connecticut DG Hosting Capacity Map and National Grid Rhode Island System Data Portal at https://eversource.maps.arcgis.com/apps/webappviewer/index.html?id=4a8523bc4d454ddaa5c1e3f9428d8d8f, and https://ngrid.apps.esri.com/NGSysDataPortal/RI/index.html, respectively.

map should be updated, and instead direct the GMSG to determine the appropriate update intervals.

Locational Value Analysis. There will likely be synergies between the Commission's ongoing Locational Value of Distributed Generation Study and the locational value analysis that will take place as part of the LCIRP process. We anticipate that the deliverables associated with step one (net load forecasting and equipment criteria violation identification) and step two (identify cost of traditional solution) of the Locational Value of Distributed Generation Study may inform the analysis occurring in each utility's LCIRP, and in some cases, future annual updates. *See* Order No. 26,221 at 5-6, 15 (February 20, 2019).

We direct the GMSG to review the deliverables of the Locational Value of Distributed Generation Study for methods or strategies that may be reasonable to adopt as a potential basis for standardized LCIRP load forecasts, solution identifications, or other relevant distribution planning inputs, and make recommendations regarding whether they should be incorporated into future LCIRPs. It may be reasonable for each utility, with the input of the GMSG, to update or conduct a locational value analysis identifying distribution system constraints that may be alleviated through targeted deployment of DERs with each LCIRP.

Load Forecasting Methodology. In the order approving the Locational Value of Distributed Generation Study, the Commission approved with minor modification the parameters proposed by Staff, which suggested that the study's baseline analysis should use each utility's existing load-growth projections, rather than requiring probabilistic load forecasting. Order No. 26,221 at 4. Moving forward, ratepayers may benefit from the enhanced accuracy associated with a move to probabilistic forecasts of load and DER growth. We direct the GMSG to review current load and DER forecasting practices, opportunities related to probabilistic load and DER forecasting, any foreseeable moves to probabilistic load forecasting by the companies in neighboring jurisdictions, and incremental costs associated with probabilistic load forecasting.

System Planning Data Transparency. In approving the scope of the Locational Value of Distributed Generation Study, the Commission directed Staff to "provide to the stakeholder working group certain material documentation, such as any reports and analyses completed in connection with the first two steps of the study process, on an interim basis during the study period." Order No. 26,221 at 15 (February 20, 2019). We expect that reports and analyses completed in connection with the first two steps of the process to include load forecasts, DER growth forecasts, and locational value estimates. Similarly, the Utilities have committed to provide a grid needs assessment in their next LCIRP filing describing all forecasted grid needs related to distribution system capital investments of $250,000 or more over a five-year planning horizon at the circuit level. Order No. 26,207 at 10; Order No. 26,209 at 22.

We find that ratepayers may benefit from the public availability of certain data relating to foreseeable grid needs, load and DG forecasts, and locational value estimates; but also acknowledge that instances likely exist where the potential harm of disclosure outweighs the public's interest in transparency. *Grafton Cty. Attorney's Office v. Canner*, 169 N.H. 319, 322 (2016). For example, certain data relating to individual customer loads or threats to system reliability may warrant protection from public disclosure. While we reiterate that transparency must be a foundational element of the least-cost integrated resource planning framework, we also confirm that we will review requests for confidential treatment under the appropriate balancing test, and do not adopt a blanket policy on energy system data disclosure.

Interconnection Practices. We find that a fast-track interconnection process for smaller resources, an interconnection portal, and tiered interconnection queue may benefit ratepayers.

We note that neighboring jurisdictions have embraced such processes and portals. Investments in streamlined interconnection processes may help advance the enhanced planning objective of facilitating DER integration by lowering certain costs while also saving ratepayer money.[17]

We direct the GMSG to develop a framework and cost-estimates related to adoption of the aforementioned fast-track interconnection processes, tiered connection queue, and portal. Once the framework and cost estimates have been developed, the companies may either file a proposal with the Commission for review, or include a proposal in their respective LCIRPs. With regard to the benefits of voltage ride-through capabilities associated with a transition to IEEE 1547, we plan to open a rulemaking docket to examine that opportunity within 18 months.

(4) Cost-Effectiveness Methodology

i. Staff Report

Staff proposed an adaptation of the framework initially developed by Dr. Ren Orans *(et al.)* for the purpose of evaluating grid modernization proposals in Hawaii. Staff Report at 45-48, citing Hawaiian Electric Companies' Modernizing Hawai'i's Grid for Our Customers, Appendix C. Within that framework, there are four separate expenditure categories and corresponding cost-effectiveness methodologies:

(1) Standards and Safety Compliance: Investments that support established criteria for providing safe and reliable service would not require a showing of net monetized benefits to ratepayers and are instead evaluated under a "least cost, best fit" approach, typically utilizing competitive procurement.

---

[17] Ardani, K. (*et al.*), National Renewable Energy Laboratory. Decreasing Soft Costs for Solar Photovoltaics by Improving Interconnection Process: A Case Study of Pacific Gas and Electric. Page 8. (Suggesting that with a total upfront investment of $1.5 million for standard net energy metered enterprise software, process streamlining, and other back-end information technology systems integration, PG&E has recuperated their original investment 16 times over, as measured by direct processing cost savings."). *See* https://www.nrel.gov/docs/fy15osti/65066.pdf.

(2) *Policy and Regulatory Compliance:* Investments that support and enable state and commission policies and regulations would not require a showing of net monetized benefits to ratepayers and are instead evaluated under a "least cost, best fit" approach, typically utilizing competitive procurement.

(3) *Net Benefits:* Investments that fall into none of the other categories but still may provide net benefits to ratepayers over the lifetime of the investment are evaluated under a cost-effectiveness test to demonstrate net benefits.

(4) *Self-Supporting Investments:* Investments where incremental costs are borne only by the customer who benefits from the investment and do not impact rates of non-participants do not require screening for cost-effectiveness. *Id*. at 46-48.

Staff suggested the appropriate methodology for the "net benefits" expenditure category may be the Total Resource Cost Test and/or another test such as the Utility Cost Test or Participant Cost Test. Staff also noted that one component of its proposed approach requiring further examination is "determining how to handle investments that would fall into more than one of the cost-effectiveness categories." *Id*. at 48.

ii. Utilities

The Utilities proposed that the current "just and reasonable" review standard be maintained for business as usual investments such as "metering, facilities, like-for-like replacement of aging infrastructure, capital repairs[,] and traditional reliability and load growth driven projects." The Utilities distinguished business as usual investments from grid modernization investments, which are made in whole or in part to "support policy goals over and above the current standard of safe and reliable electric delivery service." JU Comments at 3. The Utilities suggested that some platform-enabling investments will need to be considered in a portfolio context, as they support multiple benefit streams that may be challenging to connect directly to the enabling investment. *Id*.

For grid modernization investments, the Utilities support the framework proposed in the Staff Report. *Id*. at 4. For investments falling within the net benefits category of that framework, the Utilities propose a two-phase process for evaluating net benefits. During phase one, the Utilities would develop common assumptions relating to bulk system impact, avoided emissions values, customer benefits, discount rate, and measure lives for the purpose of net present value analysis, while also addressing inclusion of qualitative benefits. Those common assumptions would be made available for stakeholder review during a technical session. Some avoided costs, such as transmission, distribution, and operational system benefits would be utility-specific. *Id*. at 5-6. The Utilities would incorporate the common assumptions and utility-specific avoided costs into their proposed cost-effectiveness screening tests, the Total Resource Cost and the Utility Cost Test, for the purposes of evaluating investments proposed in the initial IDPs.[18] *Id*. at 6. During phase two, the Utilities propose a working group to "review use of net benefits in New Hampshire and evaluate the need for more specific guidance with respect to the use of net benefits tests," prior to submission of any subsequent IDP. *Id*.

iii. OCA

The OCA suggested that any evaluation of distribution system project costs, regardless of project type, should include: carrying costs, any undepreciated value associated with assets that are no longer used and useful as a result of the project, and a rigorous estimation of incremental lifetime capital costs, as well as operations and maintenance costs. OCA Comments at 33-34.

[18] The Total Resource Cost Test includes the costs and benefits that accrue to the utility system and participants. The Utility Cost test only includes those costs and benefits that accrue to the utility system and affect the revenue requirement.

The OCA recommended that all potential distribution capital projects be evaluated using one of three methods based on the nature of each project:

(1) *Non-Discretionary Projects:* Investments that meet a customer or regulatory requirement, or address equipment failure, are evaluated on the basis of costs. The OCA clarifies that such an approach may be understood as similar to the "least cost, best fit" approach, but emphasizes it must be accompanied by a transparent, holistic, definitive, and flexible distribution planning process in order to determine which projects are truly necessary to maintain safe and reliable service. *Id*. at 32-34.

(2) *Discretionary Projects with Readily Quantified Benefits*: Investments that are not necessary to maintain safe and reliable service, but have readily quantifiable benefits are evaluated according to the net present value of a project's ratepayer benefits.[19] Projects with a negative net present value would be eliminated from further consideration, while projects with a positive net present value would be subject to consideration within the broader capital budgeting and planning process. *Id*. at 34-36. When prioritizing projects with a positive net present value, the OCA suggests weighing the benefit-cost ratio, the size of the investment required to deliver the benefit, and the potential variability associated with the projected benefits and costs. *Id*. at 47.

(3) *Discretionary Projects with Difficult-to-Quantify Benefits:* Investments that are not necessary to maintain safe and reliable service and whose benefits are not readily

[19] When determining net present value, stakeholders would evaluate: (1) the size of benefit estimates; (2) the timing of when projected operations and maintenance benefits accrue to customers; (3) the period during which benefits accrue and discounting of those benefits; and (4) potential benefits which may not have been accounted for. OCA Comments at 34-36.

quantifiable under standard methodologies are evaluated under a risk informed decision support (RIDS) framework. *Id*. at 37-52. RIDS is a utility-led, but stakeholder-inclusive process that consists of six steps: (1) identification of priority threats; (2) characterization of sources of risk/identification of threat drivers; (3) identification of potential risk control measures; (4) estimating cost of risk control measures; (5) estimating potential measures' risk reduction value (the product of consequence cost, consequence likelihood, and the measure's reduction in likelihood); and (6) developing a list of control measures prioritized by risk reduction value. The prioritized list of risk control measures would then be considered by stakeholders as they evaluate proposed departmental and capital budgets in the context of the broader project portfolio, including non-discretionary and discretionary projects. *Id*. 37-38.

iv. CLF

CLF stressed the need for foundational investments which may not provide easily quantifiable short-term benefits, but rather, would enable markets and competition that could provide benefits from non-utility third-parties. CLF Comments at 9. CLF suggested that "[h]aving the Commission explicitly tie components of grid modernization to enabling markets and competition … would provide important policy guidance." *Id*. CLF cited the principle of "net value" defined in the Public Utilities Commission of Ohio's PowerForward Report as an example of how foundational investments may enable non-utilities to provide products and services that provide a net value to ratepayers, even if those foundational investments do not satisfy traditional cost-effectiveness tests. *Id*. at 9, 18.

v. Clean Energy NH

Clean Energy NH did not discuss cost-effectiveness methodologies in its comments.

vi. Commission Guidance

Screening Assumptions. Developing common assumptions for the purpose of net present value analysis will make the process more uniform and efficient. Based on their representations, we expect that the Utilities will file with the Commission a common assumptions straw proposal that will include a narrative describing the basis for each assumption. We direct the GMSG to review the common assumptions straw proposal filed by the Utilities, file a report upon completion of its review of the straw proposal, and request Commission resolution of any non-consensus issues. We expect that the result of that effort will be the inclusion of the list of common assumptions in each utility's LCIRP, along with any utility-specific or project-specific assumptions.

Discount Rate and Asset Life. We find that the period over which benefits accrue should be no longer than the book life of a planned investment. We decline at this time to specify a certain discount rate to apply to costs and benefits associated with distribution system investments. We expect that the Utilities will propose a discount rate for review by the GMSG in the common assumptions straw proposal.

Cost-Effectiveness and Cost of Stranded Assets. The OCA suggested that any evaluation of distribution system project costs, regardless of project type, should include: carrying costs, any undepreciated value associated with assets that are no longer used and useful as a result of the project, and a rigorous estimation of incremental lifetime capital costs, as well as operations and maintenance costs. OCA Comments at 33-34. Our current and historical approach to project cost evaluation is generally consistent with the OCA's suggested approach, except for the treatment of sunk costs associated with assets that have not been fully depreciated. Any analysis of the net present value of future investments should be forward-looking, incremental, and not include historical costs, because prudently incurred costs already approved for recovery by the Commission generally cannot be changed and will remain in place under any future investment scenario.[20] We find that undepreciated amounts associated with legacy investments that may become stranded as a result of any proposed LCIRP investment should be quantified in instances where such costs are easily ascertainable. While those costs may be considered qualitatively, we are not convinced they should be included as a cost in the benefit-cost analysis of a given project.

Categorization of Investments. Several of the commenters suggested that the type of cost-effectiveness screening methodology used for an investment should vary based on the characteristics of either the need justifying an investment (*e.g.* policy, standards compliance, safe and reliable service, etc.) or the characteristics of that investment's costs and benefits (self-supported costs, easily quantifiable benefits, hard-to-quantify benefits, etc.). Staff Report at 45-48; JU Comments at 3-6; OCA Comments at 31-32. The Staff Report recognized that "determining how to handle investments that would fall into more than one of the cost-effectiveness categories," will require further investigation. Staff Report at 48. The OCA describes the bucketing of projects into the appropriate category as the type of decision that should involve stakeholder review and input. OCA Comments at 31.

We find that stakeholder input on this key decision-point in the distribution planning process would benefit all involved. The categorization of a project for the purpose of the cost-effectiveness framework may impact how a project is prioritized and whether ratepayer benefits

[20] There are exceptions to this general rule. One recent example of an exception is the securitization of costs associated with Eversource's generation fleet. Another example is tariff provisions that require municipalities to reimburse the undepreciated cost of street lighting fixtures replaced prior to full depreciation.

are maximized.[21] The Utilities proposed that their LCIRPs include a description of known large projects with estimated budgets over $1 million. JU Comments at 19. Based on the Staff Report and related comments, we request that during LCIRP development, each utility submit an initial list of known large capital projects with estimated budgets over $1 million, or $500,000 for utilities with fewer than 100,000 customers, for guidance from the GMSG regarding the appropriate cost-effectiveness screening categorization of those projects. The initial project lists will be considered in separate utility-specific dockets. If individual but related projects undertaken across several circuits, or across a period of five years or less, exceed the above-described budgetary threshold when considered in the aggregate, we expect those projects will be included in the initial project list.

The initial list of projects should include a narrative describing the need for the project, its traceability to the grid modernization objectives, estimated approximate project costs, projected benefits of the project (quantitative and/or qualitative), potential alternatives to the planned investment, and any other information a utility deems relevant. The GMSG should strive for consensus on project categorization, but if no consensus can be reached, the GMSG may request that the Commission resolve non-consensus issues. After projects have been categorized according to the appropriate cost-effectiveness screening category, we expect the utility may update its initial project list as necessary to incorporate any revised cost or benefit estimates, or any prioritization decisions that may result. We expect any update that follows

[21] For example, if utility-side investments meant to better control voltage variation are characterized as necessary to comply with the Commission's rules, they would be screened under the least-cost, best fit approach. If those same investments in voltage optimization equipment could provide net benefits to ratepayers but may not be necessary to comply with Commission rules, it may be more appropriate – and would likely ensure ratepayer benefits are maximized – to screen them according to the test for discretionary investments with net benefits.

GMSG or Commission guidance on project categorization would help inform input on other aspects of the initial project list, such as project prioritization.

It would aid the Commission's review in this modified process if each utility provides its initial list of projects (including the narrative, cost estimates, and alternatives), provides a summary of stakeholder input, and describes changes that may have occurred as a result of further evaluation, stakeholder input, and/or Commission guidance as an appendix to its LCIRP.

The Utilities have already committed to provide a grid needs assessment in their next LCIRP filing describing all forecasted grid needs related to distribution system capital investments of $250,000 or more over a five-year planning horizon at the circuit level. Order No. 26,207 at 10; Order No. 26,209 at 22. Our guidance should be understood as supplementing, rather than supplanting that commitment. We expect the grid needs assessment – which requires identification of all distribution system capital investments of $250,000 or more, but does not require the narrative, benefit estimates, or an explanation of alternatives associated with the list of initial projects over $1,000,000 – will help stakeholders perform their due diligence in evaluating the initial project list.

Based on a review of the record, we identify four types of investments according to their characteristics and related cost effectiveness framework: (1) self-supported investments; (2) least-cost, best fit investments; (3) discretionary investments with quantifiable benefits; and (4) discretionary investments with hard-to-quantify benefits. Each of those four types of investments is discussed below and we expect that each utility's initial project list, as well as related LCIRPs, will categorize planned investments according to that framework.

Self-Supported Investments. We find that self-supporting investments, where incremental costs are borne only by the customer who benefits from the investment and do not impact rates of non-participants, do not require screening for cost-effectiveness. Staff Report at 47; JU Comments at 4; OCA Comments at 32. We observe that such treatment aligns directly with cost-causation and related rate design principles. We do not believe it necessary for the Utilities to describe self-supported projects in their LCIRPs or initial list of planned capital projects.

Least-Cost, Best Fit Investments. We accept Staff's proposed categorization of least-cost, best-fit investments as supporting standard and safety compliance as well as policy compliance, subject to the following two caveats.

First, we are concerned that an overly-broad characterization of investments necessary to support policy compliance may be inconsistent with least-cost planning. Investments which comply with certain policy-related directives, such as those directly and specifically required by statute, would clearly fall within the least-cost, best fit screening category. Less clear is whether other investments that are not specifically required by statute or regulatory guidance would also fall within that category. For example, a regulatory directive to facilitate integration of DERs would provide some degree of justification for utility investments in a hosting capacity analysis. But when a policy directive is ambiguous about the timing and scale of investment required to deliver the desired functionality, that ambiguity could lead to extensive contention as to what investments are actually necessary. While the regulatory directive to facilitate integration of DERs might sufficiently justify a relatively minor investment in a hosting capacity analysis, it may not, on its own, justify a significantly more costly investment in distribution assets necessary to accommodate reverse power flows. Yet, both investments could be characterized as supporting and enabling policy directives applicable to distribution utilities.

While we agree with Staff and the Utilities that certain investments may fall within the least-cost, best-fit category, those investments would have to be adequately supported by a description of need which directly justifies the scope and timeline of the proposed investment, and a review of alternatives which were considered to satisfy the described need.

Second, we are concerned that an overly-broad characterization of investments necessary to support reliability needs may be inconsistent with least-cost planning. For those investments justified as satisfying reliability-related needs, we expect that the description of a proposed investment will also include projections for dollars per distribution customer-minute of interruption avoided and any other ancillary benefits associated with the investment.

We anticipate that the review and input of the GMSG on the initial project list will help ensure that any proposed investments are narrowly tailored in scope and timeline to address a specific distribution system objective and associated grid need. Investments that are not narrowly tailored to a defined need, and instead address a defined need while also providing some incremental benefit may also be reasonable.[22] The incremental costs and benefits of such investments, however, should be considered within one of the discretionary investment categories for the purpose of cost-effectiveness screening.

Discretionary Investments with Quantifiable Benefits. We find that net present value analysis is an appropriate means of informing the decision whether certain discretionary investments should be considered for inclusion within the LCIRPs. Staff Report at 46; JU Comments at 5; OCA Comments at 36. The Utilities suggest that the initial LCIRPs use the Utility Cost Test (UCT) and the Total Resource Cost (TRC) test for the purpose of evaluating the costs and benefits of investments capable of providing net benefits. They also suggest that, prior to submission of any subsequent LCIRPs, a working group should be established to evaluate the

[22] One example of such an investment is the accelerated replacement of other substation equipment, initially scheduled to be replaced at a later time due to asset condition or performance, concurrent with a substation transformer replacement. Those investments, often referred to as opportunity replacements, may deliver a net benefit to ratepayers by taking advantage of economies of scope and/or scale.

use of net benefits tests and develop more specific guidance for their application in New Hampshire. JU Comments at 6. We are concerned about the impact that major revisions to the chosen net benefits test that occur between the initial LCIRP and any subsequent LCIRPs might have on multi-year investments. While we appreciate that legislative policy or regulatory guidance may evolve over time and expect that changes to the net benefits test for grid modernization investments may evolve similarly over time, we must balance that expectation with the need for consistency between LCIRP iterations. Unless facts and circumstances arise necessitating review of the net benefits test, we decline to approve the phased approach proposed by the Utilities.

For investments with benefits that can be quantified with an acceptable level of rigor and confidence, we find that the UCT is an acceptable test for determining the appropriate use of ratepayer dollars, but decline to endorse the TRC test for the purpose of evaluating net benefit investments. As we noted in Order No. 26,322, the UCT includes only those costs and benefits that affect the utility system and the distribution utility's revenue requirement. Order No. 26,322 at 4 (December 30, 2019). We believe a cost-effectiveness framework focused on the cost and benefits that directly affect a utility's revenue requirement, which in turn affects ratepayers, is the appropriate gauge of the value of ratepayer-funded system investments that have readily-quantifiable benefits.

In Order No. 26,322, we approved a transition away from the TRC test for energy efficiency programs. *Id.* at 8. In its place, we approved a cost-effectiveness screening framework consisting of a primary test, known as the Granite State Test (GST), as well two secondary tests, the UCT and the Secondary Granite State Test (GST-2). The GST and the GST-2 were developed through a several-month process where stakeholders identified, reviewed, and interpreted statutes, commission precedents, and other state guidance relating to energy efficiency. We will continue to apply that framework to the ratepayer-funded energy efficiency programs, which should be described in future LCIRPs, but are not capital projects requiring inclusion within the initial project list. Reviewing the statutes considered within the stakeholder process, we acknowledge that many of the same statutes might apply to distribution system investments. The one notable exception would be for utility-owned DERs, which may be proposed in an LCIRP, because RSA 374-G describes a unique evaluation framework for those investments. Because the review of guidance was limited to statutes and precedent relating to investments in energy efficiency, we decline to adopt the same framework adopted for energy efficiency investments for capital projects proposed in future LCIRPs. With limited exceptions, such as for ratepayer funded investments in energy efficiency and utility-owned DER investments under RSA 374-G, we expect to review the quantifiable costs and benefits associated with LCIRP investments according to the UCT.

When requesting recovery within a rate case of a specific investment that has been justified according to its projected net benefits, the Utilities should detail the accuracy of project cost and benefit projections in its request for recovery.

Discretionary Investments with Hard-to-Quantify Benefits. Nearly all commenters recognize there will be a number of proposed investments within this category, but their description of and approaches to those investments differ. The OCA suggests that discretionary projects with difficult-to-quantify benefits should be evaluated using a RIDS framework and that a prioritized list of risk control measures should be considered by stakeholders during evaluation of the broader capital budget portfolio. OCA Comments at 37-38.

We decline to adopt the RIDS process identified by the OCA for two reasons. First, we are concerned about the degree to which that level of stakeholder involvement may be interpreted as shifting of risk away from utility shareholders. Second, we are concerned that practical constraints related to time and resources would limit the viability of the process. We also observe that the OCA has not provided any evidence demonstrating where such a process has been successfully deployed by regulated electric utilities for the purpose of least-cost integrated distribution planning.

We acknowledge that risk is an important factor utilities must weigh in making decisions, including those related to proposed investments with hard-to-quantify benefits. Risk also has a significant impact on the prioritization of projects in a capital plan. While we decline to adopt the RIDS process identified by the OCA, we nonetheless expect that each LCIRP will contain a detailed discussion of how risk is evaluated for the purpose of capital budgeting and planning, and that discretionary projects with hard-to-quantify benefits identified in the initial project list will contain a detailed assessment of risks avoided where risk avoidance is a material benefit justifying the project. We further expect that the GMSG, in its review of the initial project list and consideration of project prioritization, will inform the prioritization of discretionary projects with hard-to-quantify benefits based on the costs and benefits of those investments and how they relate to the enhanced distribution system planning objectives adopted as defined above. When requesting recovery within a rate case of a specific investment that has been justified at least in part by hard-to-quantify benefits, the Utilities should include a detailed analysis regarding the accuracy of the cost and benefit projections in its request for recovery.

(5) Capital Budgeting

i. Staff Report

The Staff Report recommended an IDP that includes a five-year capital and operating plan. The plan would describe both business as usual and grid modernization investments, as well as a 10-year roadmap for meeting grid modernization objectives. Staff Report at 22, 72.

ii. Utilities

The Utilities agreed with Staff's proposed five-year capital plan and 10-year roadmap, but recommend that the IDPs contain only a high-level overview of capital budgeting processes, describing investment categories and estimated budgets rather than including a detailed discussion relative to project selection within a category. JU Comments at 17-18. Nonetheless, the Utilities clarified that their proposed IDPs would include a description of known projects with estimated budgets over $1 million. *Id.* at 19. The Utilities suggested that the IDPs should include "an update on non-wire alternatives." *Id*. at 18.

iii. OCA

The OCA asserted that distribution planning and capital budgeting are "inextricably linked," and argued that every capital budget must be supported by a distribution plan. OCA Comments at 18-19.

The OCA described nine steps of its preferred 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;[23]

[23] The OCA observed that the grid needs assessment required in Order No. 26,207 would represent a reasonable deliverable for this step and expressed support for the Commission's ongoing Locational Value of Distributed Generation Study, which would identify opportunities to avoid or defer recommended capital projects through non-wire alternatives.

(5) stakeholders identify potential alternative and/or additional projects;
(6) all potential projects are evaluated using one of the OCA's proposed three methods based on the nature of each project;
(7) stakeholders select projects and determine capital budgets;
(8) utility implements select projects and procures selected alternatives through competitive solicitation; and
(9) performance is measured using metrics and targets established in Step 2.

Id. at 20-22.

iv. CLF

CLF did not comment specifically on the utility capital budgeting process, but commented extensively on distribution system planning. CLF referenced an April 2019 whitepaper by GridLab suggesting changes to the utility capital budgeting process that would incorporate DER growth forecasts, non-wire alternatives, and DER monitoring and control. CLF Comments at 4-5. CLF further emphasized that re-imagining the utility planning and capital budgeting process should start with making visible to all stakeholders the current planning process, utility data, system needs, and system capabilities. *Id*. at 5-7.

v. Clean Energy NH

Clean Energy NH did not comment on the utility capital budgeting process.

vi. DES

DES did not discuss capital budgeting in its comments.

vii. Commission Guidance

As discussed above, we find that future LCIRPs should include a detailed description of all planned investments, rather than just those investments characterized as relating to grid modernization, subject to the caveat that a detailed narrative should accompany only those projects that meet the budgetary thresholds specified above. The OCA described nine steps for its preferred least-cost distribution planning process. OCA Comments at 20-22. We have outlined a distribution-planning framework that is similar in many respects to those steps. We decline, however, to adopt the OCA's recommendation that stakeholders should select projects and capital budgets for incorporation into an LCIRP. While it is likely that utility decision-makers will benefit from the stakeholder input provided through the enhanced planning process, we recognize that ultimately the decision to take action on a given investment must remain with the regulated entity.

Project Prioritization. We find that non-utility stakeholders can inform prioritization of discretionary distribution system investments. As noted above in our discussion of the LCIRP cost-effectiveness framework, we expect that each utility will submit an initial list of capital projects with estimated costs over a certain budgetary threshold to the GMSG to seek consensus on the appropriate categorization of each investment for the purpose of a cost-effectiveness screening. We clarify that projects described in the initial project list should be prioritized according to a utility's initial determination regarding investment priorities. In addition to providing guidance regarding the appropriate cost-effectiveness screening categorization, the GMSG will provide input regarding order of priority. If guidance from the GMSG or the Commission leads the utility to materially alter its initial project list, the utility should re-submit a revised project list to the GMSG for input on project prioritization.

We do not expect the GMSG to elevate non-consensus issues related to project prioritization to the Commission for resolution. We instead expect that the appropriate venue for the resolution of issues relating to project prioritization will be the adjudication of the LCIRP itself. In an appendix to the LCIRP, we expect each utility to provide the prioritized project list (including the narrative, cost estimates, benefit estimates, and contemplated alternatives), a summary of stakeholder input relative to project prioritization, a description of any changes in project prioritization that may have occurred as a result of further evaluation and stakeholder input, and an explanation of the basis for any deviation from stakeholder recommendations that were received.

Non-Wire Solutions. We find that meaningful consideration of non-wire solutions (NWS) within the distribution planning process may benefit New Hampshire ratepayers. We find the primary statutory support for that determination within the restructuring statute, which explicitly authorizes recovery of costs associated with investments in NWS as a means of minimizing distribution costs.[24]

The Commission has consistently supported consideration of NWS as an alternative to traditional utility solutions within distribution planning processes.[25] To date, however, no utility has successfully deployed a NWS to avoid or defer an otherwise necessary distribution system upgrade or replacement project.

We expect the Utilities to include NWS analysis in their initial project list and subsequent LCIRPs for each capacity-related capital project with an anticipated budget in excess of $1 million, or $500,000 for utilities with fewer than 100,000 customers.[26] If a utility cannot identify

---

[24] *See* RSA 374-F:4, VIII (e), "Targeted conservation, energy efficiency, and load management programs and incentives that are part of a strategy to minimize distribution costs may be included in the distribution charge."

[25] Order No. 25,111, at 31-32 (June 11, 2010) (directing Unitil to "include in its next LCIRP its strategy for minimizing T&D costs and, if relevant, the role played by DER investments in that strategy along with details of the T&D circuits or substations likely to benefit from the distributed energy resource investments."); Order No 25,625, at 8 (January 27, 2014) (directing Liberty Utilities to "provide a more comprehensive discussion of how Liberty assesses non-wires alternatives in its distribution planning ... and explain, in greater detail, how demand- and supply-side options for distribution planning are integrated by Liberty as part of its planning process."); Order No. 26,050 at 6 (August 25, 2017) (Requiring PSNH's next LCIRP filing to include "An evaluation of energy efficiency solutions for 4 kV and 12 kV substations.").

[26] In identifying NWS investment candidates, the company should consider and provide information in the LCIRP relating to: (1) the type of distribution need that may be deferred or avoided, as well as any associated cost projections; (2) the mix of commercial and residential customers on the circuit; (3) the hourly usage load profile on the equipment at issue during the 10 peak days of the most recent year and the annual peak day for each of the most recent three years; and (5) the kW peak usage of the 10 largest customers during the past three years. We expect that an analysis of non-wire solutions will include a narrative explaining the results of a solicitation of third party proposals that includes that information.

a planned investment for potential deferral or avoidance through deployment of NWS, we expect that the utility will explain why this is the case for each planned investment in capacity-related needs over $1 million, or $500,000 for utilities with fewer than 100,000 customers.

(6) Consumer Advisory Council/Stakeholder Engagement

i. Staff Report

Staff did not support a separate consumer advisory council, but did propose 13 potential working groups and suggested that stakeholders should be involved in grid modernization project pre-planning, identification, consideration, and prioritization. Staff Report at 15, 45, 72. Staff observed that a meaningful stakeholder process will need to start with current baseline data on each utility's distribution system capabilities as well as system data and management functions. *Id*. at 45, 72.

ii. Utilities

The Utilities stated each IDP cycle should include a stakeholder engagement process that allows IDP development input during listening sessions at three junctures: (1) pre-planning; (2) project area identification and consideration; and (3) investment type prioritization. JU Comments at 17. The Utilities propose to "consider feedback during the three sessions for each subsequent stage and in the final IDP submission," but "see no need for a Consumer Advisory Council or an equivalent body." *Id*.

iii. OCA

The OCA recommended that stakeholders serve an integral role in the development of each IDP, asserting that such a process can "translate the role of IOUs and stakeholders from opponents to co-contributors … with the role of the IOU chang[ing] 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.')." OCA Comments at 23. In the OCA's view, a stakeholder-driven distribution planning process may reduce the risk of cost disallowance by making "IOUs less likely to make poor decisions;" and, even in instances where poor decisions are made, they can be "cast as stakeholder-wide choices, not IOU choices … significantly reducing the pressure on IOUs to accurately predict [the] future." *Id*. at 68-69.

The OCA described numerous points during the integrated distribution planning process where stakeholders would provide input. The OCA noted that resource or bandwidth constraints may limit the ability of stakeholders to adequately evaluate, challenge, or supplement utility assumptions and proposals. The OCA observed that other Commissions "employ an Independent Professional Engineer to serve as an unbiased evaluator of technical issues as they arise in distribution planning," and "such a role is important for New Hampshire stakeholders to have available." *Id*. at 57.

iv. CLF

CLF asserted that stakeholders must have access to models and assumptions underlying the IDP and related investments so that they may review, run, or modify certain assumptions. CLF Comments at 11. CLF stated that stakeholders have a strong interest in participating in the development of objectives and functionalities of the distribution system because those objectives and functionalities form the basis for the architecture of the IDP. *Id.* at 15.

v. Clean Energy NH

Clean Energy NH supported meaningful stakeholder input during grid modernization planning. Clean Energy NH Comments at 4.

vi. DES

DES did not discuss stakeholder input in its comments.

vii. Commission Guidance

Staff observed agreement among stakeholders – that utilities should receive stakeholder input at least twice before submitting with the commission – once prior to LCIRP development and again when the utility has an initial LCIRP proposal. Such stakeholder input would address project pre-planning, identification, consideration, and prioritization. Staff Report at 45; Working Group Report at 9; JU Comments at 17. There was also agreement that stakeholders could participate in the Commission's adjudicative processes reviewing any filed LCIRP. Staff Memorandum at 5. Stakeholders did not agree on "the specifics of how any input provided would be incorporated into the" LCIRP. *Id*. Staff Report at 45; Working Group Report at 9; JU Comments at 17.

We view stakeholder involvement in distribution planning as a key driver of a more transparent, efficient, and less-costly distribution system. We agree with Staff and the Utilities, and find that stakeholders should be involved in distribution project pre-planning, identification, consideration, and prioritization. We believe that the GMSG provides a sufficient vehicle for stakeholder input into the distribution planning process and decline to adopt a separate consumer advisory council. We have embraced a framework that provides an opportunity for stakeholders to impact utility decision-making processes, including: LCIRP performance metrics and reporting requirements; adoption of distribution planning inputs and assumptions; categorization of investments for the purpose of cost-effectiveness screening; and project prioritization.

Independent Professional Engineer. We find that the review of the common assumptions, initial project list (categorization, prioritization, consideration of alternatives, etc.), and other tasks of the GMSG may benefit from the review of an independent technical expert, such as an Independent Professional Engineer (IPE) or firm providing similar services. We direct Staff to develop a scope of work for an IPE, solicit comment on that scope of work from the GMSG, and prepare a draft RFP for the Commission. We anticipate that Staff may offer the expertise of the IPE at GMSG meetings in connection with any major step in the LCIRP process. Order No. 26,221 at 15 (February 20, 2019). We also direct Staff to provide the GMSG with any material reports or analyses which are completed by the IPE regarding proposed distribution system investments. *Id*. The IPE's responsibilities should include, but not be limited to, reviewing whether non-discretionary projects are necessary to maintain safe and reliable service, reviewing the reasonableness and accuracy of capital project cost and benefit projections, reviewing alternatives to proposed projects, and reviewing whether identified grid needs may be avoided or deferred through cost-effective deployment of non-wire solutions.[27]

(7) Utility and Customer Data and Third Party Access

i. Staff Report

The Staff Report embraced the principles adopted in the Working Group Report, including:

(1) sharing data with the market in order to harness competition and drive advanced energy technology deployment;
(2) adopting common data sharing standards and protocols, such as Green Button Connect, as a means of enabling interoperability;
(3) addressing data security issues;
(4) enabling innovative rate and compensation structures through the use of interval data;
(5) making aggregated and anonymized data available if sufficient privacy protocols can be followed;
(6) making individual customer data available consistent with the protection of certain privacy standards for individual customer usage data provided by RSA 363:38; and
(7) notifying customers of the risk associated with data sharing.[28]

---

[27] The IPE should be a contractor of the Commission and work at Staff's direction.

[28] We interpret principle (7) of the energy data principles as requiring the utilities to ensure customers are aware of the risks associated with data sharing when appropriate and warranted by the facts and circumstances of a specific situation, rather than as a blanket directive for notification.

Staff Report at 55-56, citing Working Group Report at 23-26.

Staff also agreed with the Working Group Report that third party access to customer data might have benefits related to evaluation of regulatory issues, empowering customers, and enabling advanced technology solutions. *Id*. Staff compiled a list of baseline system data to better inform stakeholder input and set accurate baselines regarding utility system data, suggesting such data should be available prior to IDP development. Staff Memorandum at 2.

ii. Utilities

The Utilities suggested that extensive comments on the issue of utility and customer data and third party access are not justified in the instant proceeding because the recently enacted Senate Bill 284 (2019) "requires the Commission to open an adjudicative proceeding to review issues around access to utility and customer data."[29] JU Comments at 8.

iii. OCA

The OCA observed that SB 284 requires the Commission to open a proceeding to address issues relating to energy data. The OCA praised the law's embrace of the Green Button "Connect My Data" standard, privacy standards, and the availability of anonymized data for research purposes. OCA Comments at 61-62. The OCA further clarified that the scope of the docket envisioned within SB 284 may not fully encompass all of the energy data management components associated with grid modernization plans, and asked that the Commission remain mindful that removing all data-related grid modernization issues to the SB 284 docket would be an expansion of the docket scope originally required by that legislation. OCA Response at 2.

[29] Nonetheless, the Utilities also opine that "having utilities retain the obligation to collect, store, and manage customer data in a controlled and protected manner on an individual utility basis" is preferable to a single statewide data repository. *Id*.

iv. CLF

CLF noted the passage of SB 284 and asserted that a single centralized data repository and over-arching policy guidance "would be more effective than individual utilities developing their own policies and practices." CLF Comments at 17. CLF suggested that guidance could be developed within the adjudicative proceeding required by SB 284 and include development of a data access and data privacy framework similar to the framework established in the United States Department of Energy (DOE) Data Guard Initiative, or rules adopted by the California Public Utility Commission. *Id*. CLF also clarified that it believes "keeping the docket on customer data connected to grid modernization efforts will be important." Staff Memorandum at 2, 18, citing CLF Comment on Staff Memo.

v. Clean Energy NH

Clean Energy NH observed that the passage of SB 284 presented an opportunity to "leverage data to empower grid modernization." Clean Energy NH Comments at 2.

vi. DES

DES did not discuss energy data access in its comments.

vii. Commission Guidance

The Staff Memorandum noted that stakeholders agreed "customer data would be dealt with in a separate Commission docket pursuant to SB 284." Staff Memorandum at 2. Stakeholders also agreed that provision of certain baseline data prior to LCIRP development – an example of which is identified in an attachment to the Staff Memorandum – would help inform input on any proposed LCIRPs. *Id.*

We agree that Docket No. DE 19-197 is the appropriate venue to examine issues related to customer data. We also agree that the baseline data identified in the Staff Memorandum attachment would help inform this investigation, and we require the Utilities to file that data with the Commission within 75 days of this order.

Energy Data Principles. The Staff Report embraced a set of principles relating to customer and utility data that were identified and agreed upon within the Working Group Report as consensus principles. No comments were filed opposing those principles. We adopt the energy data principles embraced by the Staff Report and the Working Group.

Energy Data Privacy. We agree with CLF that over-arching guidance on customer energy usage data privacy is preferable to individual utilities developing their own policies or practices, and expect that a primary objective of the docket established pursuant to SB 284 will be to develop energy data privacy standards consistent with existing statutory protections, such as RSA 363:37-:38, and informed by best practices identified by the DOE and other jurisdictions.

(8) Annual Reporting Requirements

i. Staff Report

The Staff Report suggested that certain metrics would be tracked annually during reconciliation dockets. In years not requiring reconciliation, Staff recommended utilities submit brief IDP implementation status reports to the Commission. The metrics would be collaboratively developed and informed by stakeholder comments, but if no stakeholder consensus could be reached, metrics would be proposed by the Utilities in their IDPs. After metrics have been tracked for a sufficient period of time, Staff suggested performance-based and/or outcomes-based mechanisms may be established. Staff Report at 62-64.

ii. Utilities

The Utilities suggested an annual report may be appropriate to discuss progress on IDP investments, including information on implementation results, units deployed relative to plan, spending relative to planned expenditures, lessons learned, and changes to the IDPs. JU Comments at 11. Regarding performance metrics that may be the subject of the annual report, the Utilities recommended a Working Group process to establish a small set of common performance metrics that may include: DER interconnections by circuit, system automation saturation by circuit, and penetration of sensors by circuit. *Id*. at 11-12. The Utilities cautioned, however, that annual reporting requirements and investment-specific performance metrics should be proposed on a utility-specific basis within individual utility IDPs. *Id*. at 11.

iii. OCA

The OCA recommended that stakeholders define reporting requirements early in the distribution planning process, with annual performance reporting for multi-year targets, and quarterly performance reporting for annual targets. OCA Comment at 24. The OCA suggested that performance metrics should be objective, outcome-based, and limited in number. The OCA also noted, with limited exception, that performance metrics should focus on overall IDPs rather than individual investments. *Id*. at 25. The OCA cited several metrics examples, including affordability, reliability, grid energy efficiency, cost control, and DG interconnection. *Id.* at 26. The OCA did not see value in reports that update distribution plans between planning cycles, but supported annual exception reports describing deviations from the approved IDP such as those project substitutions "made or planned as a result of emerging requirements." *Id*. at 55.

iv. CLF

CLF did not comment on annual reporting requirements for distribution utilities.

v. Clean Energy NH

Clean Energy NH did not comment specifically on annual reporting requirements for distribution utilities, but expressed support for performance-based regulation, which would likely be linked to metric reporting at pre-determined intervals. Clean Energy NH Comments at 3.

vi. DES

DES did not comment on annual reporting requirements, but expressed support for performance-based regulation, which would likely be linked to metric reporting at pre-determined intervals. DES Comments at 2.

vii. Commission Guidance

Stakeholders generally agreed that an annual reporting requirement should be associated with the LCIRP, but no consensus existed on exactly what should be filed. Staff Memorandum at 3.

Annual Report Substance. We find that an annual update of certain data and information relating to the LCIRP, rather than the LCIRP itself, strikes the appropriate balance between transparency and administrative burden. To inform the on-going investigation, we require Utilities to provide an annual update of the baseline data and capabilities document, load forecasts and peaks, any material deviations from the previously approved LCIRP and budgets, lessons learned, and an update on the company's performance relative to pre-determined metrics, discussed below.

Performance Metrics. We find that an initial set of common metrics should be established through a stakeholder process. As a first step in this process, we direct the Utilities to develop a preliminary list of common metrics for stakeholder comment. Each metric should be accompanied by a narrative describing its traceability to functionalities associated with the grid modernization objectives. The Utilities should provide information on existing data capabilities and baseline data so the GMSG can assess the feasibility and best approach to achieving the goals of the General Court as embraced by the Commission. The GMSG should attempt to achieve consensus on a list of common metrics.

We recognize that certain performance criteria and metrics may be investment-specific and, therefore, not ascertainable in advance of the preliminary project list. Accordingly, when a utility solicits GMSG guidance on its initial project list it should also specify, and solicit GMSG guidance on, any performance criteria and metrics that may be associated with a given investment or investment type. When requesting recovery of a specific investment in a rate case, the utility should at a minimum detail the performance of that investment with any general and unique performance criteria and any relevant metrics to assess achievement of the goals and metrics identified in the applicable LCIRP.

(9) Rate Design

i. Staff Report

Staff embraced the rate design principles set forth in the Working Group Report, which suggested rates should: (1) provide fair compensation to utilities and consumers; (2) provide appropriate and efficient price signals; (3) incentivize customers to use electricity wisely and to invest in cost-effective DERs; (4) maximize consumer choice and control and protect vulnerable customers; and (5) reflect cost causation principles. Staff Report at 49, citing Working Group Report at 13.

The Staff Report recommended that customer charges should only be used to recover customer-related costs identified in a cost-of-service study and suggests “aligning demand charges with coincident system peak demand periods,” but clarified utilities should not assess demand charges to residential customers. *Id*. at 49-50. Staff was generally supportive of the price signals associated with time-varying rates (TVR) – including opt-out TVR as a longer-term goal for all customers – but recommended pilots and further analysis of impacts in the near term. *Id*. at 50-51. With respect to the advanced metering functionality generally associated with TVR, Staff suggested the possibility of strategic initial deployments in the form of pilots that target old meter retirements, geographic areas, large customers, or early adopters. *Id*. at 52. Staff clarified, however, that a benefit cost analysis should be conducted for advanced metering functionality prior to at-scale meter deployment, and that customers who choose to install a meter should be responsible for meter and back-office costs. *Id*.

ii. Utilities

The Utilities asserted that the appropriate forum for redesign of utility rates is within a rate case where a comprehensive review of utility costs and cost recovery occurs based on a cost-of-service study. According to the Utilities, the LCIRP or IDP might inform rate design but review of least-cost planning is not the appropriate forum for implementing such changes. JU Comments at 12.

iii. OCA

The OCA expressed appreciation for traditional cost allocation methodologies deployed via embedded and marginal cost studies and litigated in rate cases. The OCA also recommended that, an alternative cost allocation and recovery method may be warranted for some investments where the benefits mostly accrue to a specific rate class, for example, reliability investments whose monetized benefits largely accrue to commercial and industrial customers. OCA Comments at 63. The OCA asserted that rate designs should be consistent with distribution system planning investments and expressed a preference for avoiding mandatory residential customer time-varying rate structures or demand charges. *Id.* at 63-64.

iv. CLF

CLF did not specifically address rate design within its comments, but clarified in comments on the Staff Memorandum that certain grid modernization investments must be paired with rate designs/tariffs to provide value to customers and the grid. CLF commented that appropriate price signals can be the most cost-effective approach to achieving a desired grid-mod outcome. CLF further clarified that utilities should not use the mantra that "rate design belongs only in rate cases" as a justification for making grid modernization investments without pairing them with appropriate rates. Staff Memorandum at 4.

v. Clean Energy NH

Clean Energy NH suggested that advanced metering infrastructure is necessary to enable dynamic rates and reiterated the recommendation in the Working Group Report that customers should be able to opt-in to Advanced Metering Infrastructure. Clean Energy NH Comments at 4. Clean Energy NH clarified in comments on the Staff Memorandum that, like CLF, it is concerned utilities might use the mantra that "rate design belongs only in rate cases" as a justification for making grid modernization investments without pairing them with appropriate rates. Staff Memorandum at 4, 15, citing CENH Comment on Staff Memorandum.

vi. DES

DES did not specifically comment on rate resign.

vii. Commission Guidance

Staff observed general agreement among stakeholders that, aside from certain exceptions, such as pilots or investments that need to be paired with alternative rate designs, the appropriate place to address rate design is within utility rate cases. Staff Memorandum at 4. We agree that, except for certain justifiable exceptions, rate design proposals should generally be addressed within a rate case, where embedded and marginal costs are typically supported by studies available for review, acceptance, or refutation. The Staff Memorandum described pilots as an exception to the general rule, which may be addressed outside of rate cases, and which may incorporate rate design proposals.

Rate Design Principles. In our Order on Scope and Process, we required that any rate design recommendations of the grid modernization working group must be consistent with the principles of rate design that this Commission has historically supported, including efficiency, equity, simplicity, continuity, and revenue sufficiency. Order No. 25,877 at 7; *see* also, James C. Bonbright, *Principles of Public Utility Rates*, at 369-385 (1961). We adopt the Working Group recommendations cited in the Staff Report as consistent with the Commission's approach to rate design.

Customer Charges. We find that customer charges should only be used to recover customer-related costs as identified in a cost of service study. Such costs include the cost of the ratepayer-funded investments required to serve the customer, which in the Commission's experience for residential customers are typically identified as the service drop, the portion of the meter directly related to billing for usage, and the costs of billing and collection.

Peak-Coincident Demand Charges. We find that if demand charges are meant to inform recovery of distribution system costs for commercial and industrial customers, they should be coincident with the distribution system peak. Such an approach should only be implemented if peak coincident demand charge can be cost-effectively incorporated into company metering and billing systems.

Investment-Specific Rate Designs. CLF and Clean Energy NH supported the consensus on rate design issues in the Staff Memorandum with the caveat that, in order to maximize ratepayer benefits and stimulate private investment in DERs, certain investments must be paired with new rates that are a departure from current rate designs. Staff Memorandum at 4. We agree that certain investments may need to be paired with new rate designs in order to maximize customer benefits. For example, customer benefits associated with advanced metering functionality would likely only be maximized if rate designs meant to encourage reductions in demand coincident with system peak are adopted. We find that such pairings are more properly evaluated based on a full review of the facts and circumstances surrounding a specific investment or group of investments when proposed.

Cost-Allocation and Marginal Benefit. The OCA suggested that, in cases where the incremental benefits accrue disproportionately to a given class of customers, the Commission could direct a utility to allocate and recover the costs of such investments based on an apportionment of marginal benefits justifying the individual investment, rather than the embedded and marginal costs of the overall system. OCA Comments at 63. While consistent with the rate design principles of cost causation and equity, this would be a major deviation from the Commission's currently accepted practices of cost allocation and rate design.

We find that the merits of such an approach are more properly evaluated based on the facts and circumstances surrounding a specific investment or group of investments, and decline its endorsement at this time.

(10) Strategic Electrification

i. Staff Report

Building upon the objectives identified by the Working Group Report, the Staff Report identified strategic electrification of buildings, homes, and vehicles as one of the primary objectives of grid modernization. Staff Report at 11. Staff suggested that the IDP should include a proposal for strategic electrification, including electric vehicles and efficient electric appliances, and suggested that such a strategy could be implemented in conjunction with the Energy Efficiency Resource Standard (EERS) program. *Id*. at 73. The Report suggested establishing tariffed rates for electric vehicle charging and that load forecasting should include electric demand increases associated with electrification. *Id*.

ii. Utilities

The Utilities asserted that IDPs should present strategies for utilities to cost-effectively support the electrification of transportation and heating sectors. The Utilities suggested that those strategies should address: (1) utility proposals relating to public electric vehicle charging infrastructure, including "Level 2" and direct current fast charge options, as well as grid level investments to support clustered charging areas and electric heating; (2) rate structures to support electrification of transportation and heating; (3) load and peak forecasting and management approaches that lower costs that otherwise may accompany electric load-building; and (4) any energy optimization framework developed in Docket No. DE 17-136 under the Energy Efficiency Programs. JU Comments at 13-14.

iii. OCA

The OCA viewed strategic electrification as a distribution planning issue rather than a grid modernization issue and emphasized the need for load growth forecasts that accurately estimate the impact of electrification, including rate designs which might limit the peak impacts of electric vehicle charging. OCA Comments at 64.

iv. CLF

CLF stated that strategic electrification should be broader than electric vehicles and heat pumps and should include more potential measures. CLF asserted that strategic electrification should include fuel switching from oil and natural gas for space and hot water heating. In addition, as part of strategic electrification, CLF observed that shifting time of use for many appliances could benefit the distribution system and suggested that utilities develop tariffs or demand response programs that harness those dispatchable resources. CLF also suggested that natural gas utilities should be part of the planning process for strategic electrification and urged the Commission to develop a policy regarding the progress of strategic electrification in New Hampshire. CLF Comments at 11-12.

v. Clean Energy NH

Clean Energy NH cautioned against allowing strategic electrification to create opportunities for utilities to expand their monopolies rather than allowing market innovation. Clean Energy NH also recommended that electric vehicle charging stations should be accompanied by smart rate design to encourage customers to charge at times that improve overall distribution system performance. Clean Energy NH Comments at 2.

vi. DES

DES addressed strategic electrification in its comments on the Staff Memorandum, suggesting that IDPs should actively enable strategic electrification rather than passively forecasting and planning for existing growth. Staff Memorandum at 4.

vii. Commission Guidance

Staff observed agreement among stakeholders that, in light of the requirement under Senate Bill 575 (2018) that the Commission address certain policies relating to transportation electrification in a separate docket, the LCIRP process is not the appropriate mechanism for establishing guidance on strategic electrification. Instead LCIRP load growth forecasts should account for predicted levels of incremental electrification. Staff Memorandum at 4.

Efficient Electric Appliances. In Order No. 26,322, we described how an energy optimization pilot or study under the umbrella of ratepayer-funded energy efficiency programs might benefit ratepayers by exploring opportunities for improved system load factor. Order No. 26,322 at 12-13.

We find that the statewide energy efficiency programs are the appropriate vehicle for incentivizing efficient electric appliances and note that those programs already provide incentives related to high efficiency water and space heating appliances. We caution that any strategic electrification efforts targeting fuel switching through increased incentives for efficient electric appliances should be extensively proven through a study or on a pilot basis prior to program-wide adoption, and should demonstrate the accrual of benefits to non-participants through improved load factor.

Transportation Electrification. As noted above, we find that the LCIRP process is not the appropriate vehicle for establishing guidance on strategic electrification, but also agree with several commenters that rate structures may be the preferred approach to minimizing peak demand impacts of transportation electrification. We note that such structures may also provide an advantageous charging rate for customers whose per-kilowatt hour marginal costs may be less than the average customer, based on their ability to charge at times of low system demand and costs. We plan to provide guidance on rate design issues related to transportation electrification in Docket No. IR 20-004 pursuant to Senate Bill 575-FN.

Load Management and LCIRP Electrification Forecast. We find that LCIRP load growth forecasts should account for some degree of electrification. In approving the Locational Value Study scope, the Commission agreed that certain load growth forecast sensitivities should be provided, including a high load growth scenario meant to account for accelerated deployment of electric vehicles, heat pumps, and other load building end-uses. Order No. 26,221 at 14 (February 20, 2019). We express our preference for probabilistic load forecasting strategies which may account for variabilities associated with accelerated heating and transportation electrification. However, we also stress that any load forecasting methodology should account for rate designs and other strategies which will foreseeably limit peak load growth that would otherwise be associated with electrification.

With respect to DES's recommendation that the LCIRPs should actively enable strategic electrification, we believe that the guidance provided above relating to EERS energy optimization strategies and potentially advantageous rate offerings for electric vehicle charging provide the appropriate level of enablement. Ratepayers tend to benefit from the gradual and measured adoption of new programs or policies; programs or policies relating to strategic electrification are no different. We take this opportunity to draw an important distinction between the Commission's embrace of LCIRPs that enable strategic electrification and an LCIRP that embraces electrification more broadly. Policies and programs which enable strategic electrification should ensure that peak load growth is limited as much as possible and that any customer incentive, either through rates or rebates, does not unfairly subsidize participants to the detriment of non-participants. Improving load factor by increasing usage without increasing peak demand has the potential to result in lower rates for all ratepayers. *See* Order No 26,322 at 12. An LCIRP that embraces electrification without the aforementioned ratepayer safeguards meant to limit peak load growth and unreasonable subsidies would not plan for electrification in a strategic manner and, therefore, would not be a prudent investment of ratepayer resources.

Cross-Fuel Distribution Planning. CLF commented that natural gas utilities should be part of the planning process for strategic electrification. CLF Comments at 11-12. We decline to address that issue, as the docket was noticed with regard to modernization of the electric grid, and no gas utility has participated in the investigation.

(11) Consolidated Billing/General Billing

i. Staff Report

The Staff Report recommended that a benefit-cost analysis of consolidated billing, where third party retail electric suppliers are responsible for the billing and collection of distribution utility costs, be completed before any commitment is made to provide consolidated billing. Staff suggested that parties could also explore third party (non-utility, non-competitive supplier) billing. Staff Report at 62.

ii. Utilities

The Utilities asserted that consolidated billing should not be implemented in New Hampshire. In support of that assertion, the Utilities argued that such a system:

(1) will not promote greater competitive alternatives for customers;
(2) is costly, unnecessary, inefficient, and duplicative;
(3) may cause customer confusion and unnecessary administrative complexity;
(4) provides a ripe climate for scamming;
(5) will degrade the customer experience;
(6) exposes ratepayers and utilities to the financial volatility of suppliers who may have a history of default; and
(7) places timely and accurate tax collection at risk.

JU Comments at 14-17.

iii. OCA

The OCA did not view supplier consolidated billing as a significant issue but suggested that the benefits and costs of such an investment could be considered within the OCA's framework for investments whose benefits can be readily quantified. OCA Comments at 65.

iv. CLF

CLF did not comment on consolidated billing.

v. Clean Energy NH

Clean Energy NH asserted that the utilities need to develop functionality and versatility in their billing systems in order to function effectively with a modern distribution system. Clean Energy NH supported automated bill credits for net metered group members as part of needed consolidated billing functionality. Clean Energy NH Comments at 3.

vi. DES

DES did not comment on consolidated billing.

vii. Commission Guidance

Based on our review of the filings we are not convinced at this time that consolidated billing opportunities will benefit New Hampshire ratepayers. We direct the GMSG to examine the approximate costs, any quantifiable benefits, and use cases that might be associated with consolidated billing prior to any further Commission evaluation of opportunities related to consolidated billing in New Hampshire.

V. CONCLUSION

The Commission recognizes the need for a shift in regulatory focus that accounts for changes in customer needs, technology, and the electric utility industry. We reaffirm the value of least-cost integrated resource planning in our restructured jurisdiction, provide guidance on certain subject matter, and outline a process for stakeholder input and engagement during the distribution system planning process. We also commit to exploring utility compensation structure reforms that might better align the interests of ratepayers and utilities around utility performance.

We believe the stakeholder process outlined in this guidance considers and appropriately balances the need to incorporate stakeholder input into the utility planning process and the need for shareholders of regulated utilities to remain accountable for investment decisions.

We reiterate that stakeholder processes can aid the Commission in its decision-making and allow parties to reach a result in line with their expectations, the utilities' obligation to provide safe and reliable service, and the Commission's obligation to set just and reasonable rates. Even in cases where no consensus is reached during up-front collaborative processes, we expect those processes will streamline litigation by identifying non-consensus issues and the positions of the parties relative to those issues prior to adjudication. We view such processes as necessary prerequisites to any future adoption of performance-based regulation which may better align customer and shareholder interests around utility performance.

The guidance articulated today is rooted in our firm belief that evolution of the utility planning processes and compensation methods is required to ensure that customers of New Hampshire's regulated utilities continue to receive safe, adequate, and reliable service at just and reasonable rates.

Based upon the foregoing, it is hereby

ORDERED, that Commission Staff shall convene a Grid Modernization Stakeholder Group, which shall meet within 60 days and will aim to meet at least monthly for the next two years to satisfy the guidance and directives contained herein; and it is

FURTHER ORDERED, that a new docket shall be opened to receive filings and other documents associated with the Grid Modernization Stakeholder Group, with subsequent utility-specific dockets opened to consider initial projects lists and utility-specific LCIRP development processes; and it is

FURTHER ORDERED, that Commission Staff shall develop a scope of work for an independent professional engineer, solicit comment on that scope of work from the Grid Modernization Stakeholder Group, and prepare a draft request for proposals for the Commission; and it is

FURTHER ORDERED, that each Electric Distribution Utility shall file the baseline data documents, and file an annual update, described herein, with the Commission beginning August 5, 2020, and annually thereafter; and it is

FURTHER ORDERED, that the Utilities shall develop and file a common assumptions proposal with the Commission for consideration by the Grid Modernization Stakeholder Group by August 20, 2020; and it is

FURTHER ORDERED, that the Utilities shall develop and file a common metrics proposal with the Commission for consideration by the Grid Modernization Stakeholder Group by October 5, 2020; and it is

FURTHER ORDERED, that Staff, as chair of the Grid Modernization Stakeholder Group, shall within one year provide a report from the Grid Modernization Stakeholder Group recommending actions related to the topical guidance discussed herein, as well as any proposed topics of further inquiry.

By order of the Public Utilities Commission of New Hampshire this twenty-second day of May.

Dianne Martin	Kathryn M. Bailey	Michael S. Giaimo
Chairwoman	Commissioner	Commissioner

Attested by:

Debra A. Howland
Executive Director

Appendix A: Responsibilities of the GMSG

1. Common Assumptions
    - GMSG provides guidance on Common Assumptions, striving for consensus but elevating any point of contention to the Commission if necessary.
    - Input on assumptions unique to a given LCIRP/investment.
2. Common Metrics
    - GMSG provides guidance on Common Metrics, striving for consensus but elevating any point of contention to the Commission if necessary.
    - Input on metrics unique to a given LCIRP/investment.
3. Load Forecasting Methodology
    - Review current load and DER forecasting practices, opportunities related to probabilistic load and DER forecasting, any foreseeable moves to probabilistic load forecasting by the companies in neighboring jurisdictions, and incremental costs associated with probabilistic load forecasting.
4. Hosting Capacity
    - Examine neighboring jurisdictions hosting capacity maps for relevant information and best practices, including but not limited to, inputs, thresholds, and costs that may be associated with hosting capacity analysis in New Hampshire.
    - Determine the appropriate update intervals.
    - Consider an integrated approach to the availability of system planning data.
5. Interconnection
    - Develop a framework and cost-estimates related to adoption of: (1) a fast track interconnection process for small customer generation process; and (2) an interconnection portal.
6. Locational Value
    - Review the deliverables of the locational value study for methods or strategies that may be reasonable to adopt on a standardized basis for LCIRP load forecasts, solution identifications, or other relevant distribution planning inputs, and make recommendations regarding whether they should be incorporated into future LCIRPs.
    - Provide input on any updates to the locational value analysis identifying distribution system constraints that may be alleviated through targeted deployment of distributed energy resources with each LCIRP.
7. Consolidated Billing
    - Examine the approximate costs, any quantifiable benefits, and use cases that might be associated with consolidated billing.
8. Review Initial Project Lists
    - Provide guidance regarding the appropriate cost-effectiveness screening categorization of utility’s initial project list based on the project-by-project narrative describing the need for the project, estimated approximate project costs, benefits, and any alternatives to the planned investments.
    - Provide input regarding the project prioritization in the initial project list.

Service List IR 25-296 Electric Distribution Utilities May 22, 2020

ExecutiveDirector@puc.nh.gov
OCALitigation@oca.nh.gov
matthew.fossum@eversource.com
mdean@mdeanlaw.net
epler@unitil.com
Rebecca.Ohler@des.nh.gov
Joseph.Fontaine@des.nh.gov
jrodier@mbtu-co2.com
Craig.Wright@des.nh.gov
allen.desbiens@eversource.com
downesm@unitil.com
woodsca@nhec.com
heather.tebbetts@libertyutilities.com
eric.stanley@libertyutilities.com
cynthia.trottier@libertyutilities.com
frank.melanson@eversource.com
rhonda.bisson@eversource.com
robert.bersak@eversource.com
steven.elliott@eversource.com
thomas.belair@eversource.com
bob.reals@libertyutilities.com
carroll@unitil.com
palma@unitil.com
jarvis@unitil.com
snowc@nhec.com
mcnamara@unitil.com
kristi.davie@eversource.com
rick.white@eversource.com
james.shuckerow@nu.com
john.warshaw@libertyutilities.com
steven.mullen@libertyutilities.com
Pradip.Chattopadhyay@oca.nh.gov
tirwin@clf.org
kate@nhsea.org
ntreat@neep.org
edward.davis@eversource.com
maureen.karpf@libertyutilities.com
dlittell@raponline.org
katherine.peters@eversource.com
marc.lemenager@eversource.com

kggregg@myfairpoint.net
clifton.below@gmail.com
wpratt@utilidata.com
seidlerconsulting@gmail.com
j.burwen@energystorage.org
belder@eq-research.comben.kaldunski@gmail.com
wdowey@gmail.com
taylorp@unitil.com
Donald.Kreis@oca.nh.gov
karen.sinville@libertyutilities.com
michael.sheehan@libertyutilities.com
brianna@cleanenergynh.org
clayaz23@gmail.com
henry@cleanenergynh.org
sarah.cosby@dom.com
malesia.a.taylor@dom.com
langdond@axsessgroup.com
eric.chung@eversource.com
melissa.price@eversource.com
Christopher.Skoglund@des.nh.gov
DEANDRA.PERRUCCIO@puc.nh.gov
alesko@preti.com
paula.maville@lebcity.com
rburke@nhla.org
stower@nhla.org
jjazynka@energyfreedomcoalition.com
jvanrossum@clf.org
madeleine@cleanenergynh.org
erica.menard@eversource.com
Todd.Bohan@eversource.com
Christa.Shute@oca.nh.gov
cpeale@clf.org
aboyd@acadiacenter.org
pturner@clf.org
jessica.chiavara@eversource.com
kelly@cleanenergynh.org
lgallant@preti.com
jdickerson@necec.org
marc.hanks@directenergy.com
palvarez@wiredgroup.net
dstephens@wiredgroup.net
nikhil@greentelgroup.com
greg@clearpath.energy

david@clearpath.energy
Karen.Cramton@puc.nh.gov
Amanda.Noonan@puc.nh.gov
Elizabeth.Nixon@puc.nh.gov
Tom.Frantz@puc.nh.gov
steve.frink@puc.nh.gov
Stephen.Eckberg@puc.nh.gov
Al-Azad.Iqbal@puc.nh.gov
Richard.Chagnon@puc.nh.gov
Kurt.Demmer@puc.nh.gov
Suzanne.Amidon@puc.nh.gov
David.Wiesner@puc.nh.gov
Mary.Schwarzer@puc.nh.gov
F.Ross@puc.nh.gov
Brian.Buckley@puc.nh.gov
Leszek.Stachow@puc.nh.gov
James.Brennan@oca.nh.gov