



U.S. DEPARTMENT OF
ENERGY

Office of ENERGY EFFICIENCY
& RENEWABLE ENERGY



PNNL-SA-200241

Proactive Regulatory Approaches to Electrification and Load Growth

Pre-read Document to Support the July 10-11th Workshop

July 2024

Prepared by Jessica A Shipley

U.S. DEPARTMENT OF
ENERGY

Prepared for the U.S. Department of Energy
under Contract DE-AC05-76RL01830

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor Battelle Memorial Institute, nor any of their employees, makes **any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights.** Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof, or Battelle Memorial Institute. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

PACIFIC NORTHWEST NATIONAL LABORATORY
operated by
BATTELLE
for the
UNITED STATES DEPARTMENT OF ENERGY
under Contract DE-AC05-76RL01830

Printed in the United States of America

Available to DOE and DOE contractors from
the Office of Scientific and Technical Information,
P.O. Box 62, Oak Ridge, TN 37831-0062

www.osti.gov

ph: (865) 576-8401

fox: (865) 576-5728

email: reports@osti.gov

Available to the public from the National Technical Information Service
5301 Shawnee Rd., Alexandria, VA 22312

ph: (800) 553-NTIS (6847)

or (703) 605-6000

email: info@ntis.gov

Online ordering: <http://www.ntis.gov>

Proactive Regulatory Approaches to Electrification and Load Growth

Pre-read Document to Support the July 10-11th Workshop

July 2024

Prepared by Jessica A Shipley

Prepared for
the U.S. Department of Energy
under Contract DE-AC05-76RL01830

Pacific Northwest National Laboratory
Richland, Washington 99354

Acknowledgments

This document benefited greatly from the insights and suggestions of the following people:

- Glenda Oskar, DOE Office of Policy
- JP Carvallo, DOE Office of Energy Efficiency and Renewable Energy, on detail from Lawrence Berkeley National Laboratory
- Alan Cooke, Pacific Northwest National Laboratory
- Guillermo Pereira, Lawrence Berkeley National Laboratory
- Dan Boff, Pacific Northwest National Laboratory
- Jeff Deason, Lawrence Berkeley National Laboratory
- Juliet Homer, Pacific Northwest National Laboratory
- Jason Eisdorfer, Pacific Northwest National Laboratory
- Julie Peacock, DOE Vehicle Technologies Office, on detail from Pacific Northwest National Laboratory
- David Castle, Southern California Edison

Editorial support was provided by Matthew Wilburn at Pacific Northwest National Laboratory.

Funding for this work was provided by Paul Spitsen with the Policy and Analysis Team in the Office of Strategic Programs within the Office of Energy Efficiency and Renewable Energy.

Workshop co-developers and partners include Lauren Shwisberg, Becky Li, Kaja Rebane, and David Valdes from RMI.

Contents

Acknowledgments.....	ii
Contents.....	iii
1.0 Introduction	1
2.0 Context for Our Conversation	2
3.0 Our Meeting Scope	3
3.1 Customer Protections in the Current Regulatory Framework That Are Relevant for Workshop Discussion.....	4
3.2 Regulatory Challenges That Are In Scope for Our Meeting	5
3.3 Types of Risk That Are In Scope for Our Meeting.....	6
4.0 Recent Examples of Issues and Challenges Related to Proactive Approaches Arising in States and Utilities.....	7
4.1 California Proceeding to Modernize the Electric Grid for a High DER Future (Proceeding R2106017).....	7
4.2 Colorado PUC Proceeding to Study Potential Barriers to Beneficial Electrification (BE) and DERs (Proceeding No. 23M-0464EG).....	8
4.3 Minnesota Integrated Distribution System Planning for Xcel Energy (Docket No. M-23-452).....	10
4.4 Massachusetts Electric Sector Modernization Plans (ESMPs) of the Electric Distribution Companies (EDCs) (Dockets No. DPU 24-10, 24-11, and 24-12).....	12
4.5 New York, Motion of the Commission to Address Barriers to Medium- and Heavy-Duty Electric Vehicle Charging Infrastructure (CASE 23-E-0070)	13
4.6 Xcel Colorado 2024-2026 Transportation Electrification Plan (Proceeding 23A-0242E)	15
4.7 Southern California Edison 2025 General Rate Case Supplemental Load Growth Forecast Methodology (A2305010).....	15
4.8 Central Maine Power (CMP), General Rate Case (Docket No. 2022-00152)	16
4.9 New York PSC Order Addressing Ratemaking for Areas of Concern Transmission Upgrades (Case 20-E-0197).....	17
5.0 A Successful Workshop Means Identifying Specific Next Steps	19

1.0 Introduction

Thank you for taking time out of your already-crammed schedules to spend 2 days with us discussing this critical topic. We are grateful for your time and excited about the caliber and diversity of perspectives that we have gathered for our time together.

The workshop will consist of a mix of presentations, panels, large group discussions, small group work, interactive features, and networking. It will be run and facilitated by the organizing team at PNNL and RMI.

The workshop's goal is to identify proactive regulatory approaches for electrification and load growth that minimize costs and risks to customers. Our intention is that the conversations and the resulting solutions and takeaways will be specific and tactical rather than general and theoretical. We hope you will join us in working constructively to explore and create actionable next steps for key actors in the system, including utilities, regulators, thought leaders, researchers, and DOE.

At a very high level, the key topic of discussion at this workshop will be how to enable proactive electric system actions, such as grid investments or load management strategies, to accelerate beneficial electrification or address other projected sources of significant load growth rather than waiting to invest after load has materialized or in response to historical load growth patterns.

Section 5.0 of document shares more detail on how the organizing team defines successful outcomes for this workshop.

2.0 Context for Our Conversation

We are coming to this workshop with certain “givens” as the backdrop. These are trends, risks, and analytical results that are driving the need for a conversation like the one we will have. We’re providing them here as framing and boundary-setting for the workshop. While we know there might be merit in picking these “givens” apart, we’re not intending to do so in this meeting. We hope that laying out this context will be helpful – rather than artificially constraining – in guiding the scope of our conversations.

New loads are coming and will need to be managed. In the past year, estimates from US utilities of how much electricity demand will grow over the next 5 years have nearly doubled, jumping from 2.6 to 4.7 percent.¹ Many states and utilities are seeing near-term load growth from data centers and manufacturing that is dominating discussions about grid investments and load management strategies. One data center can require 50 times the electricity of a typical office building.

Taking a purely “just-in-time” approach to investments that support electrification may lead to a delay in loads being able to interconnect, reliability and service quality reductions if distribution networks are overloaded, or costly and inefficient infrastructure build-out if done in a piecemeal fashion. All of these could increase costs, delay achievement of electrification goals, and limit economic growth.

The pace of building and transportation electrification must be accelerated to meet local, state, national, and international greenhouse gas reduction goals.

¹ According to this report from GridStrategies: <https://gridstrategiesllc.com/wp-content/uploads/2023/12/National-Load-Growth-Report-2023.pdf>

3.0 Our Meeting Scope

There are many challenges to unpack and solve, including those that are technical, economic, and political in nature. We are focused on the regulatory challenges first and foremost.

These challenges may be structural or related to core regulatory tenets or processes, they may take the form of uncertainties, information gaps or methodology needs, or they may be risks faced by key actors in the system that must be mitigated.

With that said, perhaps it is helpful to articulate a couple of topics that we do not see as being within our scope. While they may warrant dedicated discussions of their own, the following are examples of topics we do not intend to dig into: supply chain constraints, permitting processes and timelines, and market conditions to support business models of non-utility solutions providers.

We are interested in digging into proactive regulatory approaches that various actors (regulators, utilities, researchers, policymakers and legislators, and potentially others) can take to address electrification and load growth.

3.1 Customer Protections in the Current Regulatory Framework That Are Relevant for Workshop Discussion

Workshop discussions may focus on the need to evolve aspects of the current regulatory framework to enable more proactive approaches. As context for that discussion, below we describe some of the core customer protections within the current regulatory framework and why they have historically been seen as fundamental regulatory tenets. For any potential changes to these concepts to be practical and durable, we should keep in mind the reasons why they exist and consider ways to maintain the fundamental benefits they provide.

Planning and procurement

- Historically, planning processes have been separate and distinct from decisions related to cost recovery. An approved plan, such as IRP and DSP, has not necessarily meant that the costs of investments identified therein would subsequently be approved for recovery from ratepayers. The additional regulatory review of costs has provided an additional layer of protection for ratepayers.
- Procurement is one utility tool for bringing new resources onto the grid. Whether a utility is within the footprint of an organized market influences the procurement options available. Generally speaking, regulators have required utilities to procure resources competitively to ensure least-cost solutions for customers. Some require utilities to include demand-side resources in competitive procurement processes.

Core ratemaking approaches

- Used and useful: utilities should invest in assets that will be used in a timely manner and useful for the identified need (e.g. appropriate, right-sized technology). This practice helps to prevent gold plating by the utility.
- Single issue ratemaking: regulators generally avoid making decisions about rates in a one-off or piecemeal fashion. Rather, they tend to review all costs and appropriate customer rates comprehensively, which protects against inappropriate or double recovery of costs.
- Just-in-time and “needs” standards: utilities should demonstrate that investments will meet a timely need which helps protect customers from paying for something they will not benefit from.

Cost allocation

- The overarching goal of cost allocation is equitable division of costs among customers. Frameworks generally look to two principles to help guide decisions:
 - Cost causation: why were the costs incurred?
 - Cost follows benefits: who benefits?
- Cost allocation is a careful analytical process to decide which group(s) of customers should pay for what, in an equitable and fair manner.

Cost recovery

- Prudence: regulators can review utility investment decisions after-the-fact and determine whether they were “prudent” given the information that the utility had, or should have known about, at the time of the investment. Prudence review and, if deemed necessary, cost disallowances, are a tool to protect customers from paying for bad or overly-risky decisions by utilities.
- Rate case review processes: significant effort goes into reviewing utility rate cases, and most utility costs are recovered through base rates to protect customers against piecemeal, ever-increasing rates or paying multiple times for the same costs.

3.2 Regulatory Challenges That Are In Scope for Our Meeting

Through conversations with attendees and research leading up to the meeting, we have identified some of the relevant regulatory challenges and grouped them into the categories below. This list is not meant to be exhaustive or to constrain the challenges that can be raised in the workshop.

Planning and procurement

- Existing planning frameworks, tools, and methods are not adequate for electrification or utilizing distributed resource capabilities over long timelines with lots of uncertainty.
- Forecasting methods that meet these challenges appear to be particularly under-developed
- Planning to manage new load in a way that maximizes its flexibility and value to the grid is an area for continued innovation.

Core ratemaking approaches

- Existing practices such as prudence review, used and useful standards, processes for demonstrating “need,” and historical test years may be constraining the ability to proactively plan and invest for electrification and load growth.

Cost allocation

- New frameworks may be needed for allocating costs of proactive procurement that protect customers, particularly low-income customers, and minimize cost shifts.

Cost recovery

- Appropriate methods for utilities to recover costs of proactive procurement that balance regulatory oversight and timeliness are needed.
- Aligning these cost recovery approaches with rate design needs continued exploration.

3.3 Types of Risk That Are In Scope for Our Meeting

There are risks associated with proactive regulatory approaches to electrification and load growth. Indeed, many of the customer protection features of the regulatory system are designed to guard against these (and other) risks. Risks will need to be mitigated for proactive approaches to be implementable, effective, and acceptable to regulators, utilities, and customers. There are also risks to *not* being proactive. The table below describes some of the risks that we expect may arise in our discussion, but it is not meant to be an exhaustive list of all possible relevant risks. We also expect that there may be emerging risks that regulators have not historically been asked to address but leave it to our workshop discussions to surface such risks.

Risk	Description
Stranded assets	Proactive investment in the grid to support electrification or other loads creates a risk that those assets will be underutilized. Over a long timeframe, underutilization creates excessive costs and risks for ratepayers or a risk that investments will be deemed not used and useful by regulators.
Acting too early	Putting costs in rate base that don't yet have associated load could put upward pressure on rates and disproportionately impact low-income customers. It could also hinder the economic case for electrification.
Acting too late	If enabling actions such as grid investments, procurement of demand-side resources, or development of new flexible load tariffs are taken too late, electrification of end uses may be delayed, new interconnections could be denied, or reliability and service quality may be diminished. This risk could also lead to missing greenhouse gas emission reduction targets that hinge on successful electrification of transportation, industry, and buildings.
Investing in the wrong place	Integration of electrified end uses and new loads will require coordination and sequencing of investments behind the meter, in the low- and medium-voltage networks, and in transmission and generation. Due to disparate decision-making frameworks and responsibilities for grid investments, there is a risk that investments will not be located, coordinated, or sequenced in such a way to minimize cost and risk to ratepayers or efficiently integrate loads.
Rapid technological obsolescence	Technologies needed to integrate electrification and load growth are evolving and maturing, often lacking standardization and industry-wide support. There is a risk that early investments in integration technology will result in obsolescence and potentially stranded assets or the need to replace undepreciated assets.

4.0 Recent Examples of Issues and Challenges Related to Proactive Approaches Arising in States and Utilities

In preparation for this workshop, we reviewed a selection of utility filings, dockets, party comments, and, where possible, Commission decisions and orders. Proactive actions to plan for, integrate, and manage electrification and other forms of load growth have come up in proceedings, but there do not yet appear to be any trends or best practices.

These issues arise in a variety of docket types, including distribution system plans or dockets dedicated to DERs, general rate cases, transportation electrification plans, grid modernization proceedings, construction work in progress (CWIP) authorizations, and Commission-directed investigations. For the most part, these dockets are initiated following utility proposals or filings.

The following pages provide brief summaries of the types of proposals related to proactive actions to enable electrification, frameworks or new methodologies being discussed, and issues and concerns raised by key actors, including Commissioners and staff where available. These examples are meant to be representative but not exhaustive of all relevant proposals, dockets, and filings.

4.1 California Proceeding to Modernize the Electric Grid for a High DER Future ([Proceeding R2106017](#))

Background

- In May 2023, an Electrification Impact Study completed for the California Public Utilities Commission (CPUC) published bottom-up load forecasting and system-level electrification impacts and cost estimates. It examines the potential impacts of high DER (including electrification) adoption on the distribution grid.
- In March 2024, CPUC staff released a proposal for improving the Distribution Planning Process (DPP).² Staff noted that historic change in load growth (including from TE) plus a conservative and reactive DPP means that utilities have fallen behind on distribution capacity work and that is leading to energization delays and long lead times.

New Frameworks or Methodologies

- The Electrification Impact Study used a novel, granular, bottom-up forecasting methodology for where and when distribution grid enhancements would be needed.
- The Staff proposal suggests extending the planning horizon to 10 years (from 5 currently) in the DPP. It argues for allowing utilities to use bottom-up, known load data in load forecasts even if that exceeds the CEC's forecasted growth. It proposes a new concept of "pending loads," which are loads that are reasonably expected but not are yet part of formal customer applications. Many questions about the practical use of pending loads are posed. Staff also propose the use of scenario planning to improve load forecasts and propose the use of more flexible inputs for utilities to request distribution capacity costs in their GRC.
- SCE proposes that the CPUC allow IOUs to apply for incremental funding between GRCs and, in doing so, allow the utilities to provide a full showing of the additional investment need, including a full justification, as opposed to the current mechanism, which provides this

² <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M527/K221/527221491.PDF>

after expenditures have been made.³ SCE also recommends that the CPUC adopt a new framework for mid-cycle funding that allows upfront per se reasonableness based on compliance with detailed rules and guidelines, along the lines of what is already done for energy procurement costs.

Summary of Issues or Concerns Raised

- Regarding pending loads, Staff asks how to de-risk those loads, where and when they should be used, how to implement the concept, and how it should interact with the CEC's forecast. PG&E argues that utilities need authorization to use pending loads to justify project investments in the GRC.
- Scenario planning to improve load forecasting and disaggregation has varying levels of support from utilities and other parties. A key question is how to incorporate the results of multiple scenario analyses into a single investment plan.
- Utilities and the Staff proposal raise the need for a mechanism to enable incremental cost recovery between GRC authorizations, pursuant to requirements in SB 410, which was passed in 2023.⁴ SCE has commented that the existing mechanism for cost recovery between rate cases is flawed because it does not provide for "upfront reasonableness determination of a utility's planned long-term investments."
- Were expedited or truncated review processes to be adopted, how can stakeholders be assured that non-wires solutions are being considered on a level playing field?

4.2 Colorado PUC Proceeding to Study Potential Barriers to Beneficial Electrification (BE) and DERs ([Proceeding No. 23M-0464EG](#))

Background

- The CO PUC opened this proceeding in September 2023. The goals included:
 - Completing a legislatively required study of potential barriers to beneficial electrification (BE) and DERs.
 - Examining existing utility tariffs and interconnection policies and practices to determine if they pose barriers.
 - Examining whether DSP can better plan for future BE and DER investments to align with the state's greenhouse gas emission reduction goals.
 - Looking at the application of cost allocation in grid upgrades.
- The Hearing Commissioner (Megan Gilman) initially issued two sets of questions to the IOUs. In the fall of 2023, the Commission began to hear concerns about Xcel CO's inability to connect new electric capacity in certain areas.
- A consultant study, *Impact of Investor Owned Utilities' Tariffs, Policies, and Practices on Beneficial Electrification and Distributed Energy Resources*, was posted to the Commission website on March 14, 2024.

³ <http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=532677198>

⁴ SB 410 allows California utilities to recover costs between general rate cases, subject to prudence review by the CPUC.

- In May 2024, the CO Legislature passed SB 24-218, which impacts how the Commission and utilities address these issues and others going forward. For example, the law requires the PUC to develop a cost recovery mechanism to allow utilities to recover grid investment costs on an annual basis.

New Frameworks or Methodologies

- After a series of workshops, on April 18, 2024, the Hearing Commissioner issued an interim decision recommending improvements to Xcel CO's processes to reduce barriers.⁵
- Short-term recommendations include:
 - Improve communications around receiving and processing information for new or upgraded service, including enhancing the current “conceptual capacity check” process.
 - Improve transparency around cost allocation and alternatives available when the Company determines that new load will require grid upgrades.
 - Load forecasting criteria should include compliance with state goals – including beneficial electrification – and the Company should consult with municipalities and large developers on their energy plans to better inform load forecasting.
- Long-term recommendations include:
 - Consider new capacity availability maps on the Company's website.
 - Consider a capacity reservation pilot to be included in the 2024 DSP filing.
 - Consider a “cluster study” approach to projects that are all on a similar timeframe.
 - Consider preparing 2024 DSP forecasts using information from municipalities' current energy plans.

Summary of Issues or Concerns Raised

- Stakeholder input included concerns that the current practices and policies related to serving new or expanded load have created an inefficient system which results in reactive, piecemeal additions to the system. This obfuscates, delays, or disincentivizes customer adoption of electrification and may hinder other developments such as housing.
- Xcel stated that the biggest challenges in ensuring timely upgrades to the distribution system are supply chain issues and permitting. The Hearing Commissioner responded to this with several recommendations on how the Company could respond to these challenges.
- Issues around cost allocation for grid upgrades were raised, but the Hearing Commissioner notes that revisiting line extension policy and cost allocation principles is not appropriate for this proceeding.
- The Hearing Commissioner recommends “immediate steps” be taken to improve the communication and processes for service requests, distribution system upgrades, and forecasting.

⁵ https://www.dora.state.co.us/pls/efi/efi_p2_v2_demo.show_document?p_dms_document_id=1019380

4.3 Minnesota Integrated Distribution System Planning for Xcel Energy (Docket No. M-23-452)

Background

- Xcel filed its 2023 Integrated Distribution Plan (IDP), which included its 2023 Transportation Electrification Plan, on Nov 1, 2023.⁶ Xcel states that its distribution strategy is to “proactively invest in our distribution system so that capacity is available before our customers need it as well as prepare our system to accommodate increasing penetration of DERs.”
- Xcel proposed \$190 million for proactive hosting capacity upgrades for 2025-2028. Xcel did not identify specific uses for this funding and sought stakeholder and Commission feedback.
- Xcel and other stakeholders propose that EV charging customers on managed or off-peak charging programs should not have to pay interconnection costs.
- Some history: In the 2021 rate case, Xcel proposed \$12 million in capital additions to prepare for increased load growth from EVs and electrification. The program was found to be too speculative and was rejected by the Commission.

New Frameworks or Methodologies

- Xcel has begun using LoadSEER in planning processes to illustrate long-term aggregate feeder peak load under different scenarios. It is a spatial forecasting tool that predicts how much, where, and when power must be supplied. Stakeholders have requested more information on the accuracy and precision of these forecasts. Fresh Energy proposes that Xcel consider using a 576-hour time series for load forecasting in an effort to expedite the inclusion of LoadSEER results into the company’s capital investment plans.
- Fresh Energy suggests that the Commission direct Xcel to develop a low, medium, and high commercial and residential electrification forecast in the next IDP.
- Fresh Energy proposed two draft frameworks in their initial comments in this docket.⁷ They acknowledge that these ideas are not yet fully developed and will require further stakeholder discussions to agree on final approaches. First, they proposed an approach for thinking about the differences between cost allocation for interconnection upgrades and proactively planning for upgrades. The Cost Allocation and Proactive Construction Matrix below, taken from their comments, illustrates how these concepts can be combined into several possible approaches which have different benefits and risks to different entities. In considering the role of proactive upgrades, Fresh Energy proposed four “pillars” that investments should meet, shown below. On both ideas, Fresh Energy sought feedback from other parties.

⁶ Docket 23-453 at the Commission’s docket search page:
<https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showDocketsSearch&searchType=new&userType=public>

⁷ See Fresh Energy’s Comments:
<https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={5003FC8D-0000-CB16-9E11-62D8C339A246}&documentTitle=20243-204016-01>

Fresh Energy’s Cost Allocation and Proactive Construction Matrix⁸

	Proactive Construction	Reactive Construction
Shared Costs	<ul style="list-style-type: none"> • Build distribution budgets around DER and electrification forecasts. • Assign incremental infrastructure costs via typical class cost allocation methods, e.g., in next rate case. 	<ul style="list-style-type: none"> • Grid upgrades are made in response to individual customer requests. • Costs assigned via typical class cost allocation methods, e.g., in the next rate case.
Individually Allocated Costs	<ul style="list-style-type: none"> • Build distribution budgets around DER and electrification forecasts. • Individual customers, where appropriate, pay a fee to cover their share of the upgrade at the time of interconnection. 	<ul style="list-style-type: none"> • Grid upgrades are made in response to individual customer requests. • Individual customers, where appropriate, pay a fee to cover their share of the upgrade at the time of interconnection.

Fresh Energy’s Pillars for Proactive Upgrades⁹

1. **Useful:** Proactive upgrades should be located in a relevant spot, needed, and useful.
2. **Timely:** Proactive upgrades should be reasonably certain of being useful within a specific period of time.
3. **Efficient:** Proactive upgrades that are recovered in base rates should be paired with programs that require or encourage efficient use of the grid (such as charging/discharging at preferable times to maximize utility of the infrastructure).
4. **Equitable:** The costs and benefits of proactive upgrades should be equitably distributed, and any upgrades recovers in base rates should prioritize projects serving under-resources customers or under-served areas of the system.

- In proactively planning investments in hosting capacity, the City of Minneapolis suggests that Xcel layer the hosting capacity map with equity indicators and with data obtained from local governments on climate and energy goals to determine where investments may be needed to support those goals and ordinances.
- The Commission is expected to issue its decision on Xcel’s 2023 IDP on July 2, 2024, and therefore may make for discussion fodder at the workshop.

Summary of Issues or Concerns Raised

- Proactive upgrades might be appropriate for some customer classes and technology areas where adoption is being hampered by the status quo. Parties tend to agree that more discussion is needed to create a framework for developing and selecting actual proactive investment projects.

⁸ See page 17 of Fresh Energy’s comments, <https://www.edockets.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId={5003FC8D-0000-CB16-9E11-62D8C339A246}&documentTitle=20243-204016-01>

⁹ See page 19 of Fresh Energy’s comments

- It may be possible to solve some of the problems identified by improving efficiency and speed of the current (“reactive”) processes or adjusting cost allocation for non-proactive upgrades.
- Need a better understanding of the grid upgrades that would have a net revenue benefit for ratepayers and those that would make sense to be paid for over time by future interconnecting customers. Scenario analysis in the IDP could be “more well-rounded” if it also included a capital expense analysis. Integrating forecasting and capital investments plans is an area for continued discussion and iteration.
- There is concern that if proactive upgrades are based solely on forecasted adoption rates of electrified technologies, those investments will disproportionately serve higher-income areas.

4.4 Massachusetts Electric Sector Modernization Plans (ESMPs) of the Electric Distribution Companies (EDCs) (Dockets No. [DPU 24-10](#), [24-11](#), and [24-12](#))

Background

- The utilities submitted their respective Electric Sector Modernization Plans (ESMPs) on January 29, 2024 in separate but closely linked dockets. The Department of Public Utilities (DPU) issued an Interlocutory Order on February 20 deferring the review of cost recovery mechanisms, budgets, capital investment projects, cost allocation, rate design, and performance metrics to subsequent phases or proceedings.¹⁰
- The “2022 Climate Act,” codified as G.L. c. 164, § 92B, directed utilities to develop an ESMP and provides the elements of a standard of review for the DPU to use.¹¹
- The DPU is directed to evaluate each ESMP and approve; approve with modifications; or reject each ESMP. Section 92B (d) further directs that, for the DPU to approve an ESMP, the Department must find that the ESMP (i) provides net benefits to customers and (ii) meets the following threshold criteria:
 - Improve grid reliability, communications and resiliency;
 - Enable increased, timely adoption of renewable energy and distributed energy resources;
 - Promote energy storage and electrification technologies necessary to decarbonize the environment and economy;
 - Prepare for future climate-driven impacts on the transmission and distribution systems;
 - Accommodate increased transportation electrification, increased building electrification and other potential future demands on distribution and, where applicable, transmission systems; and
 - Minimize or mitigate impacts on ratepayers of the Commonwealth, thereby helping the Commonwealth realize its statewide GHG emissions limits and sub-limits.

¹⁰ <https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/18641747>

¹¹

<https://malegislature.gov/Laws/GeneralLaws/PartI/TitleXXII/Chapter164/Section92B#:~:text=The%20electric%20company%20shall%20be,heard%20in%20a%20public%20hearing>

- The utilities state that the investments proposed in the ESMPs are not intended to meet a near-term customer or reliability need; rather, they are “incremental” and intended to meet one or more statutory objectives.

New Frameworks or Methodologies

- The utilities were required by law to prepare electric demand forecasts for three different planning horizons, including five-year and ten-year forecasts and a demand assessment through 2050 to account for future trends.
- The Attorney General’s office suggested that the DPU develop an export tariff methodology for cost allocation and cost recovery to enable utilities to proactively plan for DER interconnection over the long term.¹²
- To provide sufficient revenue to fund the required upgrades, the EDCs proposed that a reconciling mechanism be developed to recover the costs of ESMP investments.
- The utilities state that they are not seeking preauthorization or preapproval of their budgets but rather that the DPU should establish a budget cap for the proposed cost recovery mechanisms. They argue that prudence review at the time of cost recovery will be a check on utility spending.¹³

Summary of Issues or Concerns Raised

- The AG office states that an additional cost reconciliation mechanism specific to ESMP investments should not be authorized without (1) a convincing demonstration that such exceptional cost recovery is merited and (2) the development of safeguards to protect ratepayers from the financial risk of premature investments.
- Regarding load forecasting, concerns were raised that the utilities should collaborate and align load forecasting methodologies including sensitivities for key assumptions. Some parties want the utilities to comprehensively consider load management potential for buildings, vehicles, storage, and demand response.
- There is general agreement that new planning solutions are needed to transition the power system to fully support the achievement of the State’s policy goals. To accomplish the transformations needed, the utilities argue that they should be allowed to implement the ESMPs in flexible way that adapts to evolving circumstances. Other parties describe a “collaborative, iterative process” that should be implemented over the ESMP five-year term.

4.5 New York, Motion of the Commission to Address Barriers to Medium- and Heavy-Duty Electric Vehicle Charging Infrastructure (CASE 23-E-0070)

Background

- The New York PSC initiated this case in April 2023 with an explicit focus on proactive investment: “This includes addressing barriers to the efficient and timely development of the

¹² <https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/19079298>

¹³ <https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/19149822>

charging infrastructure and considering revisions to utility planning process for proactive investment in EV infrastructure, particularly in high-priority locations.”¹⁴

- In initial comments, the Joint Utilities proposed a framework that included identifying concentrated loads, developing a proactive infrastructure investment plan, and authorizing recovery of costs of investments made.
- The Joint Utilities argue that areas with load constraints and where there is a high confidence of future demand should be prioritized for proactive investments.

New Frameworks or Methodologies

- In a November 2023 technical conference, the Joint Utilities proposed guiding principles for a proactive planning framework and process:¹⁵
 - Enable flexibility and speed for more nimble grid planning
 - Mitigate costs and risks of investments
 - Engage the right stakeholders
- The Joint Utilities also proposed the proactive investment proposals should contain:
 - Load projections utilizing a methodology to determine future load
 - Work scope, cost, and timeline of investment needs
 - Evaluation of proposals including the alternatives considered, risks of inaction or delay, multi-value benefits of investments, and alignment with other planning processes
- The Commission has directed Staff to submit a whitepaper with recommendations for the Commission’s consideration for public comment. This has not yet been released.

Summary of Issues or Concerns Raised

- Fleet electrification is creating a need for accelerated investment by utilities, but the existing regulatory framework does not allow utilities to keep up with that growth. Utilities need a framework for proactive planning and investment that accounts for state goals and projected customer requirements and creates a pathway for utilities to recover costs outside of rate case cycles.
- There has been some disagreement and discussion around how to prioritize areas for investments.
- Other parties raised the issue of protecting ratepayers and ensuring accountability for utilities through things like targets, metrics and reporting, or performance incentive mechanisms.

¹⁴ <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={40F19F87-0000-CE10-B9FC-579FE87EB823}>

¹⁵ <https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={D014A58B-0000-C635-BB67-63DF8C34A7FF}>

4.6 Xcel Colorado 2024-2026 Transportation Electrification Plan ([Proceeding 23A-0242E](#))

Background

- Xcel filed its Transportation Electrification Plan (TEP) in May 2023.
- Xcel included spending for infrastructure to support EV adoption and proposed to recover distribution system investment costs through a transportation electrification (TE) rider. Xcel and other parties filed a Proposed Settlement, the budget for which represented a large increase from current spending levels.

New Frameworks or Methodologies

- The utility proposed distribution improvements to facilitate public chargers and customer facility buildout in their TEP. The proposal called for recovering these costs through a TE rider rather than bringing those costs forward to a rate case.
- Final Commission decision was issued on April 10, 2024.¹⁶ The Commission did not approve the utility's proposed distribution system spending through a TE rider.

Summary of Issues or Concerns Raised

- This case illustrates tension between what is appropriate to be approved in a TEP, and through a TE rider, versus in a DSP or in a rate case.
- The Commission was concerned that distribution investments shouldn't be recovered through a TE rider, partly because distribution investments will be used for a variety of purposes other than TE.
- There's a tension between protecting ratepayers through review, oversight, and transparency of utility investments and allowing utilities to be responsive and increase access and electrify loads in a timely manner.

4.7 Southern California Edison 2025 General Rate Case Supplemental Load Growth Forecast Methodology ([A2305010](#))

Background

- SCE notes that CA decarbonization policies, particularly in electrifying the transportation sector, are increasing the pace and uncertainty of electric load growth.¹⁷
- Load growth projections typically start with the California Energy Commission's (CEC) forecast. The 2020 forecast was the most current at the time the 2025 GRC forecast was prepared, which, SCE states, does not incorporate approved or future policies. Therefore, SCE states that it was necessary to develop a supplemental TE load growth forecast.
- Another factor is the long lead times required to obtain transformers and other equipment to upgrade distribution or transmission facilitates to integrate large loads.

¹⁶ https://www.dora.state.co.us/pls/efi/EFI_Search_UI.Show_Decision?p_session_id=&p_dec=30806

¹⁷ <https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M508/K571/508571681.PDF>

See 02-Volume 07, "Load Growth, Transmission Projects, and Engineering"

- Following the load forecasting process, SCE identifies “solutions” and categorizes them into plans, including a Transportation Electrification Grid Readiness (TEGR) plan within the 2025 GRC filing.

New Frameworks or Methodologies

- The TEGR load growth projections consider state policies and SCE’s own knowledge of interconnection requests from electrifying fleets to create a supplemental load growth forecast to the CEC’s forecast.
- The supplemented forecast incorporates TE load profile assumptions that resemble a time-of-use rate responsive load profile.
- The TEGR plan lays out SCE’s proposed grid readiness actions to accommodate CA’s policies around TE. It uses a 10-year planning horizon and identifies projects with operational dates outside of the GRC window. The TEGR plan identified a significant increase in the volume of substation A-bank projects which have long lead times for deployment.
- The TEGR analyses resulted in approximately 10-15 percent of SCE’s sub-transmission and distribution systems being included for proposed grid development.
- Comments have been filed by interveners within the GRC, but the Commission has not yet responded.

Summary of Issues of Concerns Raised

- The TEGR plan is based on SCE’s analysis of load growth projections. At least one intervener (Public Advocates Office) takes issue with the projections and provides a different analysis of policies, charging behaviors, and load shapes.
- Concern about rate increases is raised by multiple interveners.
- Some interveners are concerned that SCE’s TEGR plan is not ambitious enough in terms of proactive investments to support TE.

4.8 Central Maine Power (CMP), General Rate Case ([Docket No. 2022-00152](#))

Background

- CMP proposed capital adjustment mechanisms outside of its base capital investment plan for pole replacements and upgrades, EV charger projects, two energy storage projects, and upgrades to metering systems to accommodate its TOU proposal
- CMP states that the EV charger and energy storage project categories are new and important initiatives.
- CMP proposed to recover costs from these initiatives based on a showing of actual prudent expenditures in the prior year.

New Frameworks or Methodologies

- CMP proposed a multi-year rate plan that it argued would provide a clear recovery path to make multi-year programmatic investments that are necessary to modernize the grid from a centralized one-way power system to a decentralized two-way system.

- Three-year rate plan adjustments include yearly review of plant addition amounts and potential downward reconciliation in the event of underspend. Proposal also includes capital adjustment mechanisms.
- CMP included the consideration of 4-5 alternative rate design options targeted toward, among other things, the optimized use of electric vehicles and heat pumps, as well as consideration of a further TOU rate structure.
 - Proposed options include a standard TOU plan, a heat pump specific rate (flat rate - low winter price, high summer price), and an optional rate focused on electrification (higher fixed charge, low flat volumetric).

Summary of Issues or Concerns Raised

- Maine PUC Commissioners expressed concerns regarding the overall level of capital spending and pre-approving 3 years of rate increases without appropriate guardrails to ensure customers receive the benefits of the increased spending (wanted quantitative reliability and customer service metrics to verify that proposed spending provided maximum value to customers).
- The revenue requirement accepted by the Maine PUC does not include any funding for the proposed EV charger or energy storage projects and will not be adjusted during the rate plan term to recover any costs incurred for any of the capital projects covered by the proposed capital adjustment mechanisms.
- Central Maine Power concluded in the Expedited Rate Design Follow-On Proceeding that prior to proposing specific TOU rate design modifications, it needed additional information on the financial and consumption behavior of customers who elect to participate.

4.9 New York PSC Order Addressing Ratemaking for Areas of Concern Transmission Upgrades ([Case 20-E-0197](#))

Background

- The Accelerated Renewables Act (2020) directs the PSC to ensure that renewable energy can be cost-effectively integrated and to develop plans that “provide for the timely development of local transmission and distribution upgrades.”
- In 2021, the Commission sought the development of a portfolio of projects to enable the achievement of clean energy goals. In February 2023, the Commission approved the upgrade projects proposed by the companies for their local transmission systems in the Areas of Concern (AOC).¹⁸
- Cost recovery for these projects as approved by the Commission and FERC allowed the utilities to recover project cost, including cost of financing construction, through Allowance for Funds Used During Construction (AFUDC) from the in-service date of a project until the end of its useful life.

¹⁸ Case 20-E-0197, Order Approving Phase 2 Areas of Concern Transmission Upgrades (issued February 16, 2023) (AOC Order). The Areas of Concern are identified on page 5 of the AOC Order.

New Frameworks or Methodologies

- In October 2023, New York State Electric & Gas Corporation and Rochester Gas and Electric filed a petition requesting approval from the PSC to seek authorization from FERC to utilize 100% CWIP in rate base for local transmission projects that are needed to meet the State's clean energy targets.
- The Companies explain that the projects are large, with long development and construction schedules, and that AFUDC does not provide for cost recovery until the projects enter commercial operation. Under AFUDC, the Companies will spend more than \$1 billion for facilities that are not generating cash flow, putting their investment grade credit ratings at risk.
- The Companies assert that allowing 100% CWIP in rate base would save customers \$298 million compared to utilizing AFUDC.
- The Commission approved the Companies seeking FERC approval to utilize CWIP for these upgrades, citing the magnitude of customer savings and the financial risk to the Companies' creditworthiness metrics.

Summary of Issues or Concerns Raised

- CWIP requires customers to fund projects that are not yet being used. The Commission notes that AFUDC better aligns funding with the customers that benefit from the asset but results in a higher revenue requirement over the life of the asset.
- A central reason for the Companies' petition appears to be a concern about obtaining favorable financing for the transmission upgrades and avoiding a debt ratings downgrade. Were the Companies to be downgraded by a credit rating agency, the result would be an increased cost of debt for ratepayers.
- The Companies proposed to tag capital orders for the particular transmission projects with a unique program code to prevent double recovery of capitalization costs. The Commission required a semi-annual report detailing the capital costs incurred for these projects.

5.0 A Successful Workshop Means Identifying Specific Next Steps

In preparation for the meeting, we conducted a handful of informational interviews with attendees seeking to understand what a successful workshop looks like from their perspective. One attendee said that they would like the discussion to focus on “tactical and specific” action items, and we were inspired by this direction in developing the following list of workshop goals, as well as the meeting agenda.

From the organizing team perspective, success of this workshop looks like:

- Participants take away innovative ideas and solutions to challenges related to proactive regulatory approaches.
- Participants engage in constructive dialogue and respectfully discuss differences of opinion or preferred approaches.
- Collective agreement among the participants on:
 - Specific concepts and solutions that should be pursued or further developed
 - Next steps and action items suggested for particular groups of actors (e.g. regulators, utilities, DOE, researchers)
- Participants network and make connections with other practitioners that are grappling with similar or related challenges.
- Participants identify topics for continued dialogue that can be supported by the national labs or other institutions, for example, around things that cannot be explored in detail in this meeting but are connected or relevant to the topic of proactive regulatory approaches to electrification and load growth.

One follow-up item is already planned:

- PNNL will produce a summary report to be shared publicly. It will summarize challenges, risks, issues, and solutions in general and not attribute to any workshop attendees (unless that is desirable and agreed upon in advance)

Pacific Northwest National Laboratory

902 Battelle Boulevard
P.O. Box 999
Richland, WA 99354

1-888-375-PNNL (7665)

www.pnnl.gov