**STATE OF MAINE**

**PUBLIC UTILITIES COMMISSION**

**CENTRAL MAINE POWER COMPANY**

Request for Approval of Distribution Rate Increase and Rate Design Changes Pursuant to 35-A M.R.S. § 307

**Docket 2022-00152**

# JOINT SURREBUTTAL TESTIMONY OF RON NELSON, CAROLINE PALMER, AND NIKHIL BALAKUMAR

**Sponsored by**

**MAINE GOVERNOR'S ENERGY OFFICE**

**April 6, 2023**

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# I. Introduction and Qualifications

**Q. Please state your names, titles, and employer.**

A. **Nelson:** My name is Ronald Nelson. I am a Senior Director at Strategen Consulting.

**Balakumar:** My name is Nikhil Balakumar. I am a Manager at Strategen Consulting.

**Palmer:** My name is Caroline Palmer. I am a Senior Regulatory Consultant at Strategen Consulting.

Strategen Consulting is located at 10265 Rockingham Dr. Suite #100-4061, Sacramento, CA 95827.

**Q. Who is sponsoring your testimony?**

A. Our testimony is sponsored by the Governor's Energy Office.

**Q. Are you the same Ron Nelson, Nikhil Balakumar, and Caroline Palmer who filed direct testimony in this docket?**

A. Yes.

**Q. Did you file rebuttal testimony in this docket?**

A. No.

**Q. Does not responding to an issue indicate agreement?**

A. No. We respond to a narrow scope of issues in our surrebuttal and our not commenting on an issue should not be interpreted as agreement.

**Q. What is the purpose of your surrebuttal testimony and how is it organized?**

**A.** We respond to CMP's rebuttal testimony, the rebuttal technical conference, and rebuttal discovery. The purpose of our testimony is to evaluate and provide recommendations regarding the proposals included as part of Central Maine Power's case. In Section II, we outline why a comprehensive regulatory framework is needed to evolve the Company's grid to support Maine's energy goals. In Section III, we discuss how Multi-year Rate Plans (MRPs) should be considered within a performance-based regulation (PBR) framework. In Section IV, we evaluate and provide recommendations regarding Central Maine Power's (CMP) cost studies. In Section V, we review recent Commission orders related to rate design and analyze how the Company's rate design proposals in the current proceeding measure against our evaluation framework. In Section VI, we respond to the Company's rebuttal testimony and make additional recommendations regarding the Company's grid modernization proposal.

## II. A Comprehensive Regulatory Framework to support Maine's Clean Energy Goals

**Q. What is the purpose of this section of your testimony?**

A. In direct testimony, we made several recommendations on regulatory proceedings and processes the Commission should undertake. Below we provide additional recommendations on how the Commission can implement these recommendations in coordination with existing regulatory proceedings and processes to ensure Maine minimizes ratepayer impacts and expeditiously achieves its climate goals.

**Q. Please summarize your recommendations regarding new regulatory proceedings and processes the Commission should undertake.**

A. We recommended the Commission (1) initiate a proceeding with the goal of creating a comprehensive Performance Based Rate Making (PBR) framework[1]. We also emphasized the benefits of a formal Advance Rate Design (ARD) proceeding which would serve as a comprehensive process to consistently re-align rates with the needs of an evolving power grid.[2] Finally, we recommended the Commission leverage our proposed grid modernization framework to inform stakeholder process established in Docket No. 2022-00322.[3]

**Q. What relevant regulatory proceedings and processes is the Commission currently overseeing?**

A. The enactment of Public Law 2021, chapter 702 (L.D. 1959, An Act Regarding Utility Accountability and Grid Planning for Maine's Clean Energy Future, hereafter "L.D. 1959") required the Commission to act on PBR and grid planning.[4] Regarding PBR, L.D 1959 requires the Commission to adopt minimum service standards including specific, quantitative metrics pertaining to utility operations and activities including service quality, customer service, field service and DER interconnection.[5] Regarding grid planning, L.D 1959 establishes a 5-year integrated grid planning ("IGP") process in which the Commission will work with stakeholders to identify priorities for the IGP and

[1] ME GEO Direct Testimony, at 28.
[2] ME GEO Direct Testimony, at 58.
[3] ME GEO Direct Testimony, at 62.
[4] ME GEO Direct Testimony, at 9-10.
[5] L.D 1959 An Act Regarding Utility Accountability and Grid Planning for Maine's Clean Energy Future, Sec. 1 at 1.

issue an order directing the Company to file an IDP per the priorities established and the additional requirements established in L.D 1959.[6]

The Commission established Docket No. 2022-00279 to investigate adopting service quality standards for the Company which was a result of the Commission's recently adopted amendments to its Electric Transmission and Distribution Utility Service Standards rules (Chapter 320).[7] In the Notice of Investigation, the Commission stated the amended rule complies with L.D 1959 that provides for minimum service standards and a "report card" for T&D utilities.[8] However, the Commission has not yet adopted a performance metric for DER Interconnection which may be considered in Docket No. 2022-00345. Separately, in Docket No. 2021-00167, the Commission required utilities to submit reports on compliance with certain interconnection timelines established in Chapter 324 rules.

The Commission also established Docket No. 2022-00322 in response to L.D 1959 to establish the IGP. This proceeding is still at an early stage with the stakeholder process structure still in development.

**Q. Why is it important for all these proceedings to be planned in coordination as part of a 'comprehensive regulatory framework'?**

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[6] L.D 1959 An Act Regarding Utility Accountability and Grid Planning for Maine's Clean Energy Future, Sec. 8, at 6-7
[7] Notice of Investigation, Docket No. 2022-00279, at 1.
[8] Notice of Investigation, Docket No. 2022-00279, at 1.

A. Maine has ambitious energy goals to address the challenges posed by climate change, reliance on expensive fossil fuels, and aging infrastructure while creating a more resilient, modern, clean, and affordable grid.[9] Each of the regulatory proceedings and processes described above represent critical and interrelated levers the Commission should use to cost-effectively and expeditiously achieve Maine's climate and energy goals. PBR serves as a vehicle to establish and incentivize clear outcomes for the Company to achieve aligned with the State's policy goals. Those outcomes should drive how the Company will 1) design, plan, and operate their grid and 2) develop new rate designs and 3) any other relevant regulatory proceedings. Considering these regulatory proceedings and processes in silos creates the significant risk that the Company's planning and operations will not be aligned with state policy goals and thus lead to a less cost-effective clean energy transition for ratepayers.

**Q. How would you recommend the Commission sequence and coordinate across these regulatory proceedings and processes?**

A. The Commission should start by defining clear outcomes for the Company which would inform any other regulatory processes such as integrated grid planning and advanced rate design. Outcomes should not only include the minimum service standards required in L.D 1959 but State policy goals dependent on the Company's actions including reducing

[9] ME GEO Direct Testimony, at 8.

greenhouse gas (GHG) emissions,[10] accelerating Maine's transition to electric vehicles,[11] modernizing Maine's buildings with heat pumps and energy efficiency,[12] ensuring adequate affordable clean energy supply leveraging offshore wind, distributed generation and energy storage,[13] growing Maine's clean energy economy[14] and improving the resiliency of communities.[15] Once these outcomes are established, tracking metrics should also be developed for each outcome to inform measure the Company's progress and inform the development of future performance metrics.

While the ideal vehicle to define and develop tracking metrics for these outcomes would be a comprehensive PBR proceeding as previously recommended, Docket No. 2022-00279 appears to be concluding with parties engaged in settlement discussions.[16] We recommend the Commission consider leveraging the stakeholder process in Docket No. 2022-00322 to define outcomes and develop the corresponding tracking metrics. The stakeholder process is at its infancy and already includes a diverse set of stakeholders representative of the key parties with a stake in achieving Maine's climate goals cost-effectively. Defining and tracking these outcomes is also a critical first step to informing

[10] Maine Climate Action Plan, at 28.
[11] Maine Climate Action Plan, at 41.
[12] Maine Climate Action Plan, at 47-52.
[13] Maine Climate Action Plan, at 12.
[14] Maine Climate Action Plan, at 65.
[15] Maine Climate Action Plan, at 83.
[16] Protective Order No.1 (Confidential Settlement Information), Docket No. 2022-00279, at 1.

the development of and the Company's progress in implementing an IDP process that efficiently achieves state policy goals.

Once stakeholders have defined outcomes and the associated tracking metrics, the Commission should issue a ruling formalizing these outcomes and tracking metrics to inform the IDP and other proceedings. Issuing a ruling mid-proceeding will ensure the Company and stakeholders have clear guidance when developing the IDP. Stakeholders can then begin to determine how the IDP will be developed which will include developing roadmaps for grid planning, operations and architecture aligned with these outcomes[17]. These same outcomes should also be used in parallel to begin the ARD proceeding.

## III. Rate Plan

**Q. What is the purpose of this section of your testimony?**

A. We respond to CMP's rebuttal testimony on its proposed Rate Plan, including its new rebuttal proposals such as SQIs and earnings sharing mechanism. We continue to recommend rejecting CMP's Rate Plan.

[17] ME GEO Direct Testimony, at 63-64.

## A. Proposed SQIs are Inadequate for PBR Metrics

**Q. Does CMP's rebuttal claim to propose metrics to "ensure its accountability to the Commission and customers with respect to its performance under its proposed Rate Plan?"**

A. Yes. In response to the November technical conferences, CMP's rebuttal identifies ten Service Quality Indicators ("SQIs") related to electric operations and customer service performance and proposes a downward revenue adjustment mechanism that would impose financial consequences on the Company should its performance fall below the standard set by these SQIs.[18] CMP proposes a netting approach that would award the Company points for SQI performance that exceeds a given target and use those points to offset any other negative SQI performance points for SQI performance that fails to meet the target, thereby reducing the annual downward financial adjustment to CMP's allowed revenues.[19]

**Q. Does CMP's SQI design process follow best practices?**

A. No. CMP's proposal to net positive and negative performance is not common; in fact, "the Company is unaware of any jurisdiction that sums negative and positive results when determining a negative revenue adjustment for a regulated utility."[20]

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[18] PP-REB at 6-7.

[19] PP-REB at 11, lines 4-9. The Company justifies adding this netting feature as a response to Staff's Bench Analysis statement that the Company's rebuttal "should include…possible financial rewards for exceeding the targets." *See* CMP response to GOVEO 003-012.

[20] CMP response to GOVEO-003-012.

**Q. Should exceeding SQI performance targets result in a positive financial incentive for the Company?**

A. No. CMP is a monopoly service provider and should be required to deliver service at a minimum level of service quality. The proposed SQIs are examples of traditional core utility services (e.g., customer service and reliability) which already have downside financial consequences within some traditional regulatory frameworks. The reason that traditional regulatory frameworks have penalties for not meeting minimum quality metrics is that rates should not be deemed just and reasonable unless core services meet a minimum threshold; otherwise, the Company can cut costs and increase profits to the detriment of ratepayers.

CMP's proposal to offset underperformance on some metrics with overperformance on other metrics gives the Company a positive financial incentive, by reducing its overall annual downside penalty. The Company should not be able to avoid penalties for poor performance in traditional core service areas by obtaining credit for performance in other areas. This is an inequitable approach as customers may be impacted differently by each performance metric. For example, commercial customers could benefit more from a metric that the Company excels on while residential customers may be harmed more on a metric that the Company performs poorly on, creating an inequitable outcome for residential customers. It also creates gaming opportunities for the Company whereby it could invest in metrics that are cheaper to excel at and cancel out poor performance in areas that are more expensive to perform in. These examples demonstrate why the Company's approach is unreasonable and why metrics should be carefully designed to ensure that financial incentives are aligned with ratepayer interests. In most cases, ensuring incentive alignment takes time and should be done in dedicated dockets, not in general rate cases (although final approval can take place in general rate cases due to the impact on rates).

**Q. Are CMP's proposed SQIs the kind of metrics that form part of an advanced PBR framework?**

A. No. The SQI proposal does not satisfy the requirements of a more advanced alternative regulatory framework because it only addresses these traditional core services. In fact, the SQI metrics the Company proposed in its rebuttal consist only of the metrics that the Commission had identified for measuring Maine's large T&D utilities, plus one based on Staff's Bench Analysis.[21] The Company should be held to these basic standards whether or not it uses a MYRP. A MYRP should only be permitted when a utility commits to performance standards that extend beyond the traditional regulatory framework, such as improving load management and greenhouse gas emission performance, as we discuss further below. PBR that would justify a multi-year rate plan would require that the Company aim for – and track and report on – exceptional performance on metrics that are outside of its traditional core services and aligned with emergent policy and energy sector

[21] CMP response to GOVEO-003-010.

priorities. The Company should meet its minimum service quality requirements regardless of the regulatory framework.

**Q. Do states with advanced PBR structures have performance incentives and metrics that reach well beyond traditional core services?**

A. Yes. Hawaii, Connecticut, Illinois, North Carolina, and Vermont have implemented incentives and metrics related to DER adoption and utilization, emissions reductions, peak load reduction, interconnection, and EV adoption and integration, among others.[22]

**Q. What are some of the performance incentives that those other states have adopted?**

A. The Illinois Commerce Commission recently adopted Peak Load Reduction (PLR) incentive mechanisms for Ameren and ComEd. Both PLR incentives were based on Witness Nelson's proposals, particularly Ameren's. The PLR incentives had the objective of lowering resource adequacy requirements (through demand response, primarily), a target level of performance, performance levels that result in upside and downside rewards, and reporting requirements. Ameren's PLR target is procuring and incremental amount of 25 MWs[23], which is quite significant based on that utility's current load management portfolio, while ComEd's is 150 MW[24] and also ambitious.

[22] Connecticut and North Carolina's processes are both ongoing and no commission orders on final incentives and metrics have been issued.
[23] Illinois Commerce Commission, Docket No. 22-0063, Order, https://www.icc.illinois.gov/docket/P2022-0063/documents/328505, at 92-93
[24] Illinois Commerce Commission, Docket No. 22-0067, Order, https://www.icc.illinois.gov/docket/P2022-0067/documents/328509, at 134

Another example is Hawaii’s accelerated Renewable Portfolio Standard (RPS) performance incentive mechanism (PIM), which financially rewards the utility for more rapidly adding renewables than is required by statute. Additionally, Hawaii has a low to moderate income (LMI) energy efficiency PIM[25]. The LMI Energy Efficiency PIM incentivizes the utility to deliver energy savings for LMI customers with two metrics to support this PIM: (1) a "savings" metric, which would measure the delivery of energy savings to LMI customers beyond a specified baseline; and (2) a "participation" metric. which would measure increased participation by LMI customers in programs offered by Hawaii Energy.

**Q. What are some of the tracking metrics that those other states have adopted?**

A. Hawaii, Vermont, and Illinois have adopted numerous tracking metrics related to utilization of DER, load management, EV integration, interconnection, and equity, among other metrics. For example, Green Mountain Power tracks a behind the meter battery program’s (that allows third-parties to participate) performance in lower regional network service charges.[26]

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[25] Hawaii Public Utilities Commission, Docket No 2018-0088, Decision and Order No. 37787, at 21-22.
[26] https://greenmountainpower.com/news/gmp-nearly-doubling-energy-storage-through-innovative-agreements-to-boost-savings-for-customers/

Another example is the Illinois Commerce Commission's adoption of Witness Nelson's recommendation to require Commonwealth Edison and Ameren to track a broad set of metrics to implement their peak load reduction PIM which include the following[27]:

- Load reduction capability interval data and load reduction capability customer contracts
- Load reduction capability measured as a weather normalized peak impact;
- Total MW of firm capacity meeting resource adequacy needs;
- Total cost per MW of firm capacity meeting resource adequacy needs;
- Number of times a contingency, program, or other event is called;
- Total and percentage MW and megawatt-hour ("MWh") participating;
- Number of customers participating;
- Percentage of event hours called in top 250 system hours;
- Kilowatt-hour ("kWh") delivered by time period.
- Customer EV Rate Participation
- Total kWh EV Charging
- Customer Active Managed Charging Participation
- Total EV demand response performance in MW and MWh and PJM revenues and costs

[27] Illinois Commerce Commission. 2023. *Case 22-0432 Order*, pg. 88. https://www.icc.illinois.gov/docket/P2022-0432/documents/335467/files/584484.pdf

**Q. Are any of those performance incentives and metrics applicable to Maine?**

A. Incentives are more complex and contentious because there are financial consequences tied to them, meaning that an incentive would take longer to develop in Maine. However, most tracking metrics are applicable to Maine and could be useful for developing baselines for future PIMs.

**Q. Do you have any other critiques of the Company's proposed SQIs?**

A. Yes. The thresholds set for triggering the penalties appears to be too large. The Company must miss some targets by as much as 100% to be penalized. This threshold is unreasonable and it is unclear how it was determined.

**Q. What do you recommend regarding the SQI proposal in CMP's rebuttal?**

A. We recommend that the Commission reject the netting approach to the financial incentive and tighten the thresholds for penalties. Ideally, the redesign of the SQIs could be through a comprehensive docket looking more broadly at incentives and metrics.

## B. Insufficient Procedural Process / Rate Plan Component Checklist

**Q. Does CMP claim that the mere inclusion of certain PBR features justifies its Rate Plan?**

A. Yes. CMP claims that the enhancements it proposed in rebuttal mean that its Rate Plan "includes all of the key features of a properly designed performance-based rate plan, as identified by…the GEO's witnesses…and therefore should be approved."[28]

**Q. Do CMP's rebuttal proposals address your concerns about CMP's Rate Plan?**

A. No. Our point in direct testimony was not that a utility needs to simply include these components as part of a checklist. Instead, the utility must carefully craft these components with the input of stakeholders, and clearly demonstrate their reasonableness and their value to ratepayers. The design of the mechanisms is more important than their presence. Because many of these regulatory mechanisms are about shifting risk between ratepayers, the utility, and shareholders, poorly designed regulatory mechanisms can shift an unreasonable amount of risk onto ratepayers. This shift of risk can provide significant benefits to the utility and shareholders, and not only provide little benefit to ratepayers, but harm ratepayers through a regulatory framework that does not effectively contain costs and achieve state policy goals.

**Q. Has the Company undergone sufficient process in establishing its PBR framework?**

A. No. Setting goals, then related outcomes, then representative metrics is one of the most important processes when creating a PBR framework; however, no emergent policy goals are reflected within CMP's PBR framework design, including its SQI metrics. This is a significant issue because, in many states, transitioning to a PBR framework is premised

[28] PP-REB at 2.

on the very notion that emerging state policy goals cannot be achieved under traditional regulatory frameworks. The achievement of state policy goals is a key benefit to ratepayers and provides justification for allowing utilities more leeway for collecting revenues through beneficial mechanisms, such as MYRPs and decoupling mechanisms.

We have already described how CMP's rebuttal SQI proposal does not satisfy a comprehensive PBR framework. As an additional example: in rebuttal, CMP proposes an earnings sharing mechanism, under which any earnings that the Company realizes during a rate year over 150 basis points above the ROE used to set rates would be shared equally (50/50) with customers. The Company does not explain how it chose 150 basis points as the threshold for sharing earnings, how common that threshold is, or why the proposal benefits ratepayers. Based on our experience with ESMs, the 150 basis point threshold is high and should be rejected. While we continue to recommend a more holistic process to design these details, if the Commission adopts an ESM, a 25 basis point threshold would be more appropriate.

The interaction of the PBR framework components must complement one another to provide sufficient benefits for ratepayers and therefore justify the switch to a PBR framework. CMP has failed to achieve this and therefore has not met its burden of proof to show that a MYRP and its complementary components will result in just and reasonable rates.

**Q. Has CMP indicated its regard for process in other regulatory actions?**

A. Yes. In the rebuttal technical conference, the Company noted that moving to a standard offer (or opt-out) TOU rate for the residential class would be too large of a regulatory change  for one case and that "it needs to be a collaborative effort, not just with the company but also with the commission and other stakeholders."[29] However, CMP has proposed a complete overhaul of its regulatory system in the rate case with minimal process or stakeholder collaboration. It is unclear how it is reasonable to redesign the entire regulatory framework with minimal process, when it would apparently require extensive engagement to educate customers on time varying rates – something they experience in almost every other industry (e.g., air travel, bowling alleys, freeways, car sharing, and movie theaters, among others) as well as in other utility jurisdictions (e.g., Sacramento Municipal Utility District and DTE). The Company's openness to sudden regulatory framework changes – in contrast to its hesitation regarding TOU – may have more to do with how the utility prioritizes revenue recovery mechanisms, than the difficulty of the task.

**Q. What do you recommend regarding CMP's proposed Rate Plan?**

A. If the Commission approves a rate increase, we recommend that the increase only be permitted for one year and for the proposed MYRP Rate Plan to be rejected.

## IV. Cost of Service

**Q. What is the purpose of this section of your testimony?**

[29] Transcript 16th at 50.

A. Rebuttal proceedings revealed that CMP calculated local facilities costs based on two unsubstantiated assumptions: 1) needing larger and more expensive transformers and 2) lowering the average number of customers who can share a transformer. We discuss how such distribution system assumptions – plus N-1 design standards for transformers and no incorporation of load management or smart inverter functionalities – result in higher local facility charges that CMP proposes to recover through higher fixed charges.

We also reiterate our position from direct testimony that such costs are not appropriate for inclusion in monthly fixed charges. Customers' use of transformers is not fixed, and variation in consumption leads to variation in customers' responsibility for transformer costs, which therefore should not be recovered through fixed charges.

Finally, we reiterate our position that the basic customer approach is a superior methodology for classifying customer-related distribution costs within an ECOSS and is widely used in other states, and that CMP's rental method for calculating marginal customer costs is susceptible to subjective determinations that may inflate costs within the MCOSS.

## A. The Impact of Distribution System Engineering Assumptions Within the MCOSS

**Q. How do distribution system engineering assumptions impact the MCOSS?**

A. As identified in our direct testimony, cost studies and rate design involve utilities making numerous subjective assumptions that can significantly impact the COS results and associated rate design recommendation. CMP revealed in rebuttal that it made certain distribution system planning assumptions in its MCOS study that have the effect of inflating its design demand concept, causing the Company to justify a higher customer charge recommendation.

**Q. How do substation transformer design and planning criteria impact the MCOSS?**

A. Distribution design criteria are used to inform the design of the distribution system. For example, an N-1 distribution design criterion means that when a substation's peak load is served by one transformer, the utility must install two transformers to ensure no load is lost if one transformer goes offline. The N-1 design criterion is not required by any entity (e.g., NERC), but it is not unusual. Other design criteria include minimum transformer sizes. Minimum transformer sizes are also not required by any reliability entity and are often left to utility judgement. Obviously, these design criteria can have significant implications on how much the distribution system costs to build.

Distribution criteria for transformer constraints are often a percent of nameplate or emergency ratings. Utilities forecast load to identify capacity constrained transformers based on these criteria. Each constrained transformer results in greater marginal capacity costs, which CMP proposes to collect through a fixed monthly or demand charge. Importantly, how a utility specifies and defines a capacity constrained transformer will determine how many transformers are constrained and the assumptions for replacement.

These design and planning criteria are not often scrutinized by regulators but have significant impacts on system costs and the results of marginal cost studies. They are also becoming increasingly important as DERs and smart inverters proliferate.

**Q. What criteria does CMP use for specifying substation transformer ratings and identifying constrained transformers for upgrade?**

A. CMP uses a few different criteria. Under standard conditions, called N-0, substation transformers are designed to operate within their normal rating. Substations must also meet contingency conditions, called N-1, in which one transformer is inoperable. In this situation for multi-transformer substations, CMP's planning criteria dictates that the smallest transformer must be sized large enough to support the entire station load under its Long-Term Emergency rating. For single transformers, there must be adequate distribution interconnections with other area networks to switch the loads. Meanwhile, in-service transformers and feeders are considered constrained when they are loaded above 90% of rated capacity.[30]

**Q. Should planning criteria be updated to integrate DER capability?**

A. Yes. As technology changes, distribution planning criteria should evolve to integrate smart inverter functionality, to minimize distribution investments and fully integrate DERs into the system.[31] As mentioned in our direct testimony, enabling non-firm capacity allows the utility to avoid T&D infrastructure upgrades to serve what would otherwise be firm capacity requirements.[32]

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[30] CMP Response to GOVEO-003-002 Attachment 1, p. 8-11

[31] Indeed, the GEO advocated for adoption of IEEE-1547-2018 for smart inverter capabilities in the currently open docket on interconnection. *See* Maine Governor's Energy Office. *COMMENTS OF THE MAINE GOVERNOR'S ENERGY OFFICE*. Case No. 2022-00345

[32] GEO Direct at 55.

For example, EV Automated Load Management (ALM) limits the import requirements of customers at the point of interconnection. Limiting the import requirements would impact the sizing of local facilities on the distribution system (as well as upstream requirements). This calls into question whether increasing the minimum size of a transformer is reasonable. Another example is that active network management enables non-firm export, which essentially changes a utilities N-1 design criteria by allowing curtailment of export as opposed to installing larger substation transformers to avoid backflow. Similar technologies are available for curtailing import, but that control is not often reflected in distribution design criteria (i.e., locally specific demand response).

**Q. Does CMP's planning criteria reflect smart inverter capabilities?**

A. It is unlikely that they do. CMP's N-1 design criteria assumes that, even with high DER penetrations, each substation transformer must be large enough to bear the entire load or export of the circuit. N-1 assumptions exclude any concept of non-firm export or import and ignores the bi-directional nature of the modern distribution system.

To be clear, it is not common for utilities to integrate DER and smart inverter capabilities at this time. However, regulators should increase scrutiny in this area, given the potential for significant cost savings for ratepayers.

Additionally, these are the types of issues that should be explored during pilots, such as the active network management pilot. Every pilot should have an objective. Determining how active network management impacts design and planning criteria would be a useful objective.

**Q. Did CMP recently change any distribution system planning assumptions for the MCOS study?**

A. Yes. The Company's rebuttal testimony reveals that its 2022 MCOSS assumed changes in local distribution transformer sizing. The MCOSS "takes into account that, going forward, the transformers will be larger than those historically installed for the average customer."[33] Apparently, the Company intends to phase out 10 kVA transformers, making 25 kVA the smallest standard size transformer.[34] CMP also reduced the assumed number of customers that can share a given transformer (thereby increasing the per-customer "design demand" in the MCOSS).[35]

**Q. Why has CMP increased the assumed size of transformers?**

A. The Company stated that this is reflective of CMP's distribution planning anticipation that electrification trends will increase electricity demands[36]

**Q. Has CMP provided analysis to document or support either of its changed transformer assumptions?**

A. No. The company has not officially analyzed or supported these changing transformer assumptions, stating "The Company has not officially documented the need for a change in transformers per customer distribution transformer installations."[37]

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[33] MCOS Rebuttal at 6:6-8
[34] Technical Conference Transcript 3/16/23 at 206:14-18.
[35] CMP Response to GOVEO-003-016
[36] CMP Response to GOVEO-003-016
[37] CMP Response to GOVEO-003-016

**Q. Has the Company considered if local transformer capacity constraints can be avoided with load management?**

A. No, the Company's planners said that CMP had not considered load management.[38] Witness Nieto acknowledged that it is possible for load management to lower capacity requirements, although it would depend on the terms of the program.[39] Importantly, because CMP has not explored load management, it implicitly has not offered or considered terms that would avoid increased local (or system) capacity requirements.

**Q. How can local transformer constraints be addressed by load management?**

A. Load management can be and is used to avoid local distribution system upgrades. In our direct testimony, we described Automated Load Management ("ALM") as one potential solution to capacity limitations for both customer and utility owned equipment.[40] ALM is one approach to lower capacity requirements at the local facility level.

Additionally, third-party service providers, such as WeaveGrid, are already commercializing technologies to track and coordinate EV charging to ensure grid reliability. WeaveGrid's technology can be used to manage local facility loading on the distribution. For example, WeaveGrid can coordinate and schedule a cluster of EVs in the same local region on the grid by using telematics and information on the EVs state of

[38] Technical Conference Transcript 3/16/23 at 22:13-20
[39] Technical Conference Transcript 3/16/23 at 25:1-16
[40] GEO Direct at 72-75

charge. By scheduling charging in sequence, EVs can be charged over night with a significantly decreased local peak load requirement. However, instead of researching and developing EV and other load management programs, the Company is proposing to increase local transformer capacity by 2.5 times with no support. The decision to increase transformer size is directly used to support the Company's fixed charge increase by inflating its per customer design day cost estimates, while load management programs would be recovered through volumetric rates and likely reduce capital investments for the Company.

**Q. What is the impact of increasing the per-customer design demand for local transformers?**

A. Because CMP proposes to recover costs associated with line transformer and local conductors via a monthly fixed facilities charge, an increased design demand results in categorizing higher costs to the fixed monthly charge. The Company calculates that reducing the assumed number of customers per transformer raises the proposed facilities cost per-customer by $2.47, from $17.83 to $20.30.[41] This is a 12% increase in local facilities costs based on multiple assumptions that are not backed up by Company analysis. In the above calculation, the Company assumes that 1.5 customers are served from a 10 kVA transformer, and that 3 customers are served from a 25 kVA transformer. This is a downward adjustment from the historical average of 1.56 customers served by a

[41] CMP Response to GOVEO-003-017.

10kVA transformer and 3.78 customers served by a 25kVA transformer. It is not clear why the Company assumed a 3.8% decline in the number of customers served for 10kVA transformers but a 20.6% decline for 25kVA customers.

**Q. What is the impact of increasing the assumed size of transformer installations?**

A. The Company stated that the incremental price difference between the two transformers is about $390 on average – or a 28% increase over 10 kVa transformer prices in 2022[42] – but did not calculate the impact of this price increase on the claimed measure of design demand nor the resulting facilities cost per customer. Of course, a higher-cost transformer would lead to higher proposed costs to be recovered via the monthly fixed charge.

**Q. Do you object to the change in transformer size?**

A. We take no position on whether this is a needed change or not. However, changes to design and planning assumptions should be supported by analysis and optimally a cost benefit analysis. Additionally, these changes and support for said changes should be made more transparently and be vetted by stakeholders.

## B. Design Demand

**Q. What concern did you raise in Direct regarding CMP's design demand concept?**

A. We discussed that CMP's MCOSS does not reflect cost causation because the design demand concept is static when customer demand is not.[43]

[42] Technical Conference Transcript 3/16/23 at 206; corroborated by OPA-018-011 Attachment 1 (2022-152).
[43] GEO Direct at 33-34.

**Q. How did CMP respond to your concern?**

A. CMP continues to argue that it is appropriate to recover local facilities costs on a fixed basis using the concept of design demand, because the MCOS study assumes that once the required facilities – such as a transformer – are installed or replaced at a particular location, the per-customer cost is not expected to change over time, regardless of changes year-by-year or month-to-month customer's actual demand.[44]

**Q. Is it true that customers' actual demand has no bearing on local facility costs?**

A. No. Transformer costs are not the same regardless of the amount of energy that the customer consumes. The Regulatory Assistance Project points out that transformer usage correlates to the lifetime (and therefore the cost) of the equipment:

> A transformer that is very heavily loaded for a couple of hours a year and lightly loaded in other hours may last 40 years or more until the enclosure rusts away. A similar transformer subjected to the same annual peaks, but also to many smaller overloads in each year, may burn out in 20 years.[45]

Since the frequency of transformer replacement is linked to its customers' load shapes, line transformer cost can be closely related to customer demand. We have also

[44] Nieto Rebuttal at 2-3.
[45] Lazar, J., Chernick, P., Marcus, W., and LeBel, M. (Ed.). (2020, January). *Electric cost allocation for a new era: A manual.* Montpelier, VT: Regulatory Assistance Project (hereinafter "RAP Electric Manual"), at 148. https://www.raponline.org/wp-content/uploads/2020/01/rap-lazar-chernick-marcus-lebel-electric-cost-allocation-new-era-2020-january.pdf

described numerous load management options and smart inverter functions above that can be used to lower local facilities' capacity requirements.

**Q. Should the cost of increasing local distribution transformers be recovered through fixed customer costs?**

A. No. As we asserted in our direct testimony, customer demand changes over time and impacts the amount of needed capacity from (and thus the individual cost responsibility for) the local transformer.[46] In their rebuttal of this point, the Company sets up a circular argument for why these costs should be fixed.[47] The Company has already assumed that customer demand will increase, and therefore, will install larger local transformers for each customer. The increase in customer demand over time does not increase the cost of service, because the Company already assumed the demand increased, and installed a larger transformer. This logic could be used to categorize any cost into a fixed customer charge.

**Q. Will removing transformer costs from fixed cost recovery realign the incentives for CMP?**

A. Yes. Recovering transformer costs via volumetric charges will give the utility and customers an incentive to deploy ALM and other LM practices to control costs, as stated in direct testimony.[48] Allowing fixed cost recovery of these facilities through a fixed

[46] GEO Direct at 33:13-16
[47] MCOS Rebuttal at 6:6-10
[48] GEO Direct at 34:12-17

charge reduces this incentive because it does not create an incentive to lower that cost when revenue is guaranteed.

## C. Customer Costs

**Q. What position did you take in Direct regarding the classification of customer-related costs?**

A. In Direct, we noted that the rental method – the Company's methodology for calculating marginal customer costs – suffers from theoretical and computational issues that may result in a higher marginal customer cost. We also identified that the basic customer approach to classifying distribution system costs is more reflective of how systems are built, and is less subjective, than the Company's ECOSS minimum system method.

**Q. How did the Company respond to your position in rebuttal?**

A. The Company claims that the basic customer approach has not been widely adopted in other jurisdictions and appears to dismiss our concerns regarding the minimum system approach on the basis that the Company uses a marginal (rather than embedded) cost study. According to the Company, "[t]he Basic Customer approach has been discussed mostly in jurisdictions that do not use marginal costs for setting rate designs, and instead use embedded cost studies…In contrast, Maine relies upon marginal cost studies, not embedded cost studies, to set rate design."[49] In addition, the Company disagreed that its

[49] Nieto Rebuttal at 6-7

rental method overstates customer costs and claimed that the methodology is recognized and accepted in other jurisdictions, citing a recent California PUC order approving a rental methodology for Pacific Gas & Electric Company.

**Q. Do you agree that the Company's use of a marginal cost study is a sound basis for dismissing the appropriateness of the basic customer approach?**

A. No. The Company seems to imply that we were recommending the basic customer approach in the embedded cost of service study (ECOSS) for use in rate design. While that is common in other states, we did not make that recommendation in this case. Our point was that "Both the MCOSS and ECOSS employ methodologies that result in a higher proportion of costs being treated as customer related … ."[50] The basic customer approach is a superior methodology for classifying customer costs in an ECOSS.

**Q. Do you agree that the basic customer approach has not been widely adopted in other jurisdictions?**

A. No, quite the opposite. Numerous commissions across the country use methods that do not classify distribution system equipment upstream of the service line as a customer cost, and many have recognized the reasonableness of the basic customer approach.

For example, Rhode Island does not require the Minimum System approach and has not since at least 1984. In response to a request "that the Commission require a Minimum System Study prior to the next case to allocate costs to demand and customer

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components," the Commission found that it "is satisfied by…reasoning that it deny the request for a minimum system study and as such, rejects the request. This is consistent with the Commission's previous ruling in In Re: Narragansett Electric Co., Docket No. 1606/1692, Order No. 11227 (issued April 30, 1984) at p.7."[51]

Connecticut has a law related to the fixed charge. Specifically, the law states that a public utility's fixed charge shall "recover only the fixed costs and operation and maintenance expenses directly related to metering, billing, service connections and the provision of customer service."[52] This law speaks directly to how the fixed charge is set, as opposed to how the COSS classifies distribution system costs, demonstrating that the basic customer approach can be utilized for rate design purposes.

The Maryland Public Service Commission assessed the minimum system approach and instead approved a method similar to the basic customer approach, ruling that "[w]e find no grounds to re-allocate lines as customer-related under a minimum cost of service methodology as advocated by MEG [the Maryland Energy Group]. This proposal has not been accepted in the past by the Commission, and we are not inclined to do so now."[53]

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[51] Decision and Order, In Re: The Application of the Narragansett Electric Company d/b/a National Grid for Approval of a Change in Electic[sic] Base Distribution Rates, at 142 (April 29, 2010), Docket No. 4065 (State of Rhode Island and Providence Plantations Public Utilities Commission).

[52] CT Gen. Stat. § 16-243bb (2020).

[53] Order No. 83907, In the Matter of the Application of Baltimore Gas and Electric Company for Revisions in its Electric and Gas Base Rates, at 81–82 (March 9, 2011) Case No. 9230 (Public Service Commission of Maryland) (internal citations omitted).

The Illinois Commerce Commission rejected the Minimum System and zero intercept approach numerous times and adopted the basic customer approach, finding that "attempts to separate the costs of connecting customers to the electric distribution system from the costs of serving their demand remain problematic."[54]

The Arkansas Public Service Commission ruled that "accounts 364-368 should be allocated to the customer classes using a 100% demand methodology and…that AEEC [Arkansas Energy Electric Consumers] and HHEG [Hospital and Higher Education Group] do not provide sufficient evidence to warrant a determination that these accounts reflect a customer component necessary for allocation purposes."[55]

The Texas Public Utilities Commission stated that "[s]pecifically, the customer charge shall be comprised of costs that vary by customer such as metering, billing and customer service."[56] It has also found that "[i]t is appropriate to use a 100% demand allocator for distribution accounts 364 through 368," which is consistent with an application of the Basic Customer approach.[57]

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[54] Final Order, Commonwealth Edison Company Proposed General Increase in Electric Rates (Tariffs filed October 17, 2007), at 208 (Sep. 10, 2008), Docket No. 07-0566 (Illinois Commerce Commission).

[55] Order, In the Matter of the Application of Entergy Arkansas, Inc., for Approval of Changes in Rates for Retail Electric Service, at 124–26 (Dec. 30, 2013) Docket No. 13-028-U (Arkansas Public Service Commission).

[56] Order No. 40, Generic Issues Associated with Applications for Approval of Unbundled Cost of Service Rate Pursuant to PURA § 39.201 and Public Utility Commission Substantive Rule § 25.344, at 6 (Nov. 22, 2000) Docket No. 22344 (Public Utility Commission of Texas).

[57] Order, Application of AEP Texas Central Company for Authority to Change Rates, at 17 (Dec. 13, 2007) Docket No. 33309 (Public Utility Commission of Texas).

In 2018, the Colorado Public Utilities Commission affirmed an Administrative Law Judge's recommended decision rejecting the zero-intercept method, another methodology for creating a hypothetical minimum system, and ordering that FERC accounts 364-368 be classified as 100 percent demand-related.[58]

The Idaho Public Utilities Commission moved from the minimum system approach to the basic customer approach in 1998 because it found that the basic customer approach was a superior methodology.[59]

The Washington Utilities and Transportation Commission also ruled in favor of the basic customer approach, finding that "proponents of the Minimum System approach have once again failed to answer criticisms that have led us to reject this approach in the past. We direct the parties not to propose the Minimum System approach in the future unless technological changes in the utility industry emerge, justifying revised proposals."[60]

Although we have not conducted an exhaustive survey of all states nor do we constantly monitor each state for updates, examples from these jurisdictions demonstrate

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[58] Colorado Public Utilities Commission. (June 15, 2018). Proceeding No. 17AL-0477E, Decision No. C18-0445 in rate case for Black Hills/Colorado Electric Utility Co. https://www.dora.state.co.us/pls/efi/EFI_Search_UI.Show_Decision?p_session_id=&p_dec=25270

[59] Order No. 28097, In the Matter of the Application of the Washington Water Power Company (Now Avista Corporation dba Avista Utilities—Washington Water Power Division) For an Order Approving Increased Rates and Charges for Electric Service in the State of Idaho, at 24–27 (July 29, 1999), Case No. WWP-E-98-11 (Idaho Public Utilities Commission).

[60] Ninth Supplemental Order on Rate Design Issues, Petition of Puget Sound Power & Light Company for an Order Regarding the Accounting Treatment of Residential Exchange Benefits, (Aug. 16, 1993) Docket No. UE-920433 (Washington Utilities and Transportation Commission) (1993 WL 13812140), at 5–6.

the point that we wish to make: other jurisdictions clearly recognize the reasonableness and appropriateness of the basic customer approach and many have rejected the use of the minimum system method that CMP used.

**Q. Did the Company's citation of the California PUC's decision address your concerns regarding the rental method?**

A. No; in fact, it highlighted our concerns. In the order that CMP cited, the California PUC required several adjustments to the traditional rental method, so as to reduce the opportunity provided by the rental methodology for analysts to make subjective determinations that may inflate costs. For example, the California PUC ordered Pacific Gas & Electric Company (PG&E) to account for "the remaining lives of the assets in place and the differentials in customer growth rates" in order to distinguish between the value of new and existing equipment.[61] It must also be noted that most California utilities have relatively low fixed charges for residential customers and/or fixed charges that only apply if a customer's bill falls below a minimum threshold – both of which apply to PG&E's tariff.[62] In contrast, the Company argues that the results of its rental method indicate a need to increase the basic monthly charge faced by all customers.

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[61] D. 21-11-016, "Decision Adopting Marginal Costs, Revenue Allocation, and Rate Designs for Pacific Gas and Electric Company," Nov. 18, 2021 at 23.

[62] https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-rates; https://www.pge.com/en_US/residential/rate-plans/how-rates-work/rate-changes/minimum-bill-charges/minimum-bill-charges.page; https://www.sce.com/residential/rates/Time-Of-Use-Residential-Rate-Plans; https://www.sdge.com/total-electric-rates

## V. Rate Design

**Q. What is the purpose of this section of your testimony?**

A. We respond to the Company's rebuttal regarding its proposal to increase the residential fixed charge, which we continue to find objectionable. We also note that the Company appears open to our recommendations to create an Advanced Rate Design proceeding and to develop additional options for non-firm customers capable of deferring T&D upgrades.

**Q. Why did you recommend rejecting the Company's proposal to increase the residential service charge?**

A. We recommended rejecting the proposed customer charge increase because 1) CMP's MCOSS does not support an increased charge, 2) the Company's proposal would harm low-usage customers who also tend to be low-income and contradicts policy goals of increasing distributed generation and energy efficiency, and 3) revenue stability for the Company is not a rate design principle.

**Q. How did the Company respond to your recommendations regarding the proposed fixed charge increase?**

A. The Company argues that there is insufficient evidence to support the claim that low usage customers also tend to be low-income. Although the Company does not have data indicating otherwise, the Company states that the limited data available to the Company on customer usage and income does not support the claim that there is a relationship between these variables. The Company reiterates that customers receiving energy assistance benefits are not necessarily low usage. The Company also claims that participants in the Arrearage Management Program are not low-usage and that some low-usage customers are seasonal or vacation home customers, who are unlikely to be low-income.[63] The Company also suggests that 2015 EIA data on the Northeast region indicating that low-income customers tend to be low usage is out of date and, although the data includes Maine customers, is not specific to Maine and may not be representative of CMP's customers.[64]

In addition, the Company argues that increasing the customer charge would not decrease a customer's control over their energy bill or incentive to invest in distribution generation or efficiency upgrades because a large portion of the bill would still be volumetric.[65] The Company claims that "no conclusive evidence has been proffered by the GEO to make a compelling argument that this charge would be a decision-making factor" in a customer's decision to invest in distributed generation.[66] Finally, CMP cites Staff's claim that lower volumetric charges tend to improve incentives for electrification, all else equal, and claims that this would also improve efficiency because heat pumps are more efficient than oil boilers or gas furnaces.[67]

**Q. Did the Company's response address your concerns that increasing the fixed charge would harm low usage customers, who also tend to be low-income?**

[63] Marini, Laiho, Rauch, and Smith Rebuttal at 5-6
[64] Marini, Laiho, Rauch, and Smith Rebuttal at 7
[65] Marini, Laiho, Rauch, and Smith Rebuttal at 10
[66] Marini, Laiho, Rauch, and Smith Rebuttal at 10
[67] Marini, Laiho, Rauch, and Smith Rebuttal at 10-11

A. No. In fact, since we filed Direct in 2022, the EIA has released more recent data from its 2020 Residential Energy Consumption Survey. The 2020 survey shows the same clear and consistent relationship between household income and energy usage as the previous survey. This relationship is apparent in every region of the country, including the Northeast, as indicated by Table # below.[68]

**Table 1: Household Income and Energy Consumption, Northeast Region, 2020 RECS**

| Income | Per household energy consumption (million Btu) |
|---|---|
| Less than $5,000 | 65.6 |
| $5,000-$9,999 | 59.3 |
| $10,000-$19,999 | 65.7 |
| $20,000-$39,000 | 74.8 |
| $40,000-$59,000 | 82.4 |
| $60,000-$99,000 | 89.2 |
| $100,000-$149,000 | 95.0 |
| $150,000 or more | 120.5 |

Absent any data indicating otherwise, the Commission should err on the side of assuming that this consistent relationship between income and energy consumption that holds in the Northeast and every other region of the country also applies to CMP customers. If the Company wishes to argue that its customers are an exception to this widespread trend, it would need to provide representative data on its customers. However, the Company has provided data only on customers receiving energy assistance

[68] https://www.eia.gov/consumption/residential/data/2020/c&e/pdf/ce1.2.pdf

– a highly skewed sample, as eligible customers pursuing enrollment in energy assistance are likely to have higher energy usage and therefore greater need for energy assistance. Using LIHEAP recipients to draw conclusions about low-income customers as a whole is a common but misleading tactic to attempt to argue against the clear relationship between income and usage. Given that only 21% of eligible customers in Maine receive LIHEAP assistance,[69] we caution the Commission against focusing on an unrepresentative subset of customers to justify a proposal that would disproportionately harm the vast majority of low-income customers, who do not receive energy assistance.

**Q. Why is it important to consider the impact on low-income people when designing rates?**

A. Low-income people have higher "energy burdens," meaning that they spend a disproportionate amount of their income on energy bills. In Maine, the average energy burden across all income levels was 5 percent in 2018 – the highest rate of any state in the country. For households below the federal poverty level, however, the average energy burden was 25% – five times higher than the state average. For households earning between 100 and 150 percent of the federal poverty level, the average energy burden was 14%.[70] As of 2021, 15 percent of the population of Maine lived below 150 percent of the federal poverty level.[71] The Company's proposal would disproportionately increase energy bills

[69] https://neuac.org/wp-content/uploads/2021/02/Maine-State-Sheet-2022.pdf
[70] U.S. Department of Energy, Low-Income Energy Affordability Data (LEAD) Tool (last visited March 30, 2023), https://www.energy.gov/eere/slsc/maps/lead-tool
[71] https://www.census.gov/data/tables/time-series/demo/income-poverty/cps-pov/pov-11.html#150175

for the customers who are already spending a disproportionate share of their income on energy, further limiting the resources that such customers have to spend on food, housing, health expenses, and other essentials.

**Q. Did CMP's rebuttal address your concerns that increasing the fixed charge would decrease the incentive to invest in distributed generation and energy efficiency?**

A. No. The Company argued only that the majority of the bill would still be volumetric after increasing the customer charge. We did not argue otherwise. We noted that increasing the customer charge and correspondingly decreasing the volumetric rate would decrease the volumetric portion of the bill. The Company claims that we did not offer conclusive evidence that the level of compensation (via volumetric rates) that customers receive for DERs would be a decision-making factor. It is a basic economic premise that actors would prefer to receive higher rather than lower compensation for their investment, all else equal. Given this preference, a higher energy rate would provide a larger incentive to invest in distributed generation. A lower energy rate with a correspondingly higher fixed charge would provide a smaller incentive to invest in distributed generation. CMP proposed smaller volumetric charges relative to how much the volumetric charges would have increased in the absence of a higher fixed charge, sending correspondingly smaller incentives for investment in distributed generation.

**Q. How do you respond to the Company's claim that increasing fixed charges and correspondingly lowering volumetric rates can incentivize electrification?**

A. As stated in Direct, "we do understand that electrification may benefit from higher fixed and lower volumetric rates; however, this can be achieved through an optional tariff."[72] While an optional heating rate should be used to incentivize electrification, the default rate should maintain the current customer charge in order to avoid transferring costs to average and low-usage customers, including low-income households, as well as to incentivize investment in distributed generation and efficiency upgrades.

The state's goal of beneficial electrification is closely connected to affordability. Strategic electrification can lower costs for, and be made accessible to, all customers. As stated in the Maine Climate Action Plan, "[e]ffective preparation for increased electricity usage requires increased energy-efficiency efforts, thoughtful management of energy uses, modernization of the electricity grid, enhanced grid management systems, greater use of markets and aggregation, and accompanying statutory and regulatory policies to ensure that Maine's power sector evolves efficiently and affordably."[73] By harming low-income customers and decreasing incentives to invest in efficiency and distributed generation, increasing fixed charges is inconsistent with an equitable electricity transformation. Well-designed heating rates with strong TOU price differentials, when optional, can serve as powerful, additional incentives for electrification that lower costs for, and hold harmless, other customers.

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[72] Nelson, Palmer, and Balakumar Direct at 50

[73] https://www.maine.gov/future/sites/maine.gov.future/files/inline-files/MaineWontWait_December2020.pdf at 61

**Q. How should the Commission further evaluate different perspectives and tradeoffs related to rate design?**

A. A separate proceeding or process should be used to evaluate and collaborate on rate design. In the current case, stakeholders are arguing about how a high or low fixed charge can impact electrification. This is an overly simplistic conversation. For example, if the goal is electrification, time-varying, seasonally differentiated rates would likely be the most beneficial rate structure – not high fixed charges. In fact, Brattle conducted a similar analysis recently that came to a similar conclusion.[74] As another example consider a goal of procuring efficient customer sited DERs. If that is the goal, export tariffs could be an economical and equitable approach – not high or low fixed charges. The issue is that the goals we all want to achieve are not simple – it is not high or low customer charges. It is complex and a separate proceeding is needed to navigate these complexities.

**Q. Did the Company object to your recommendation that additional options be developed for non-firm customers capable of deferring T&D infrastructure upgrades?**

A. No. The Company stated that it is "open to further exploring a Non-Firm Customer Rate Option in a separate proceeding." [75]

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[74] Heat Pump-Friendly Cost-Based Rate Designs. Available here: https://www.esig.energy/wp-content/uploads/2023/01/Heat-Pump%E2%80%93Friendly-Cost-Based-Rate-Designs.pdf

[75] Marini, Laiho, Rauch, and Smith Rebuttal at 20

**Q. Did the Company object to your proposal to establish an advanced rate design proceeding?**

A. No. The Company stated that it "agrees with collaborating with interested parties to develop an Advanced Rate Design proposal" and "has expressed its openness to this concept through Docket No. 2021-00325."[76]

# VI. Grid Modernization

**Q. What is the purpose of this section of your testimony?**

A. The Company has proposed grid modernization investments in several categories including Electric Vehicle Programs, Grid Model Enhancement Project (GMEP), Active Network Management Pilot and the UMaine Collaboration. Below we respond to the Company's rebuttal and provide updated recommendations to the Commission in each of these areas.

## A. Electric Vehicle Programs

### (i) Dedicated EV Regulatory Process

**Q. Did you make recommendations in direct testimony on a broader regulatory process for EV issues?**

[76] Marini, Laiho, Rauch, and Smith Rebuttal at 19

A. Yes. We recommended the Commission consider the development of roadmaps for EV grid planning, operations, and architectures as part of a broader EV grid modernization proposal outside of this rate case and with more extensive stakeholder input.[77]

**Q. Would you like to expand upon these recommendations?**

A. Yes. Maine's transportation electrification goals of 41,000 light-duty EVs by 2025 and 219,000 EVs by 2030[78] require immediate action by both the Commission and the Company. Below we update our recommendations for modifications should that the Commission approve the Company's Light-Duty EV Make-Ready, Medium- and Heavy-Duty EV Make-Ready, and EV Planning Analysis and Activity programs. We also make additional recommendations to ensure the Company takes a comprehensive approach to transportation electrification. The Company will need to develop and submit plans, seek stakeholder input, and provide updates on its progress and activities to implement these recommendations. To address these issues, we recommend the Commission utilize a comprehensive EV proceeding, Docket No. 2022-00322 or another appropriate proceeding to implement, monitor, and iterate on these recommendations. This EV proceeding would also serve as a vehicle to consider all future EV related issues.

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[77] ME GEO Direct Testimony, at 85-87.
[78] Maine Climate Action Plan, at 41.

### (ii) Make-Ready Programs

**Q. Please summarize your recommendations from direct testimony related to the Light-Duty EV Make-Ready Program and the Medium- and Heavy-Duty EV Make-Ready Program.**

A. In direct testimony, we recommended that the Commission make the following modifications to the Company's proposal if the Commission approves a Light-Duty EV Make-Ready Program and/or Medium- and Heavy-Duty EV Make-Ready Program:

- Coordinate the Company's EV programs with DOT and EMT on the implementation of the National EV Infrastructure (NEVI) Program and other programs.
- Restructure program incentives to cover a percentage of total make-ready costs, rather than a percentage of utility-side make-ready costs.
- Require the Company to develop a standard site evaluation methodology to determine whether ALM can be used to cost-effectively meet the customer's charging need.
- Leverage the Council on Environmental Quality's Climate and Economic Justice Screening Tool for a more holistic definition of disadvantaged communities.
- Modify incentive levels under the Light-Duty EV Make-Ready Program to prioritize publicly accessible chargers and chargers located in disadvantaged communities.

- Modify incentive levels under the Medium- and Heavy-Duty EV Make-Ready Program to prioritize school buses and transit buses, as well as fleets serving disadvantaged communities.
- Target at least 40% of program funds towards disadvantaged communities.

Additionally, we recommended that the Company address in detail in rebuttal testimony how EV rates and managed charging offerings will be incorporated into the proposed programs.

**Q. How did the Company respond to your recommendation for coordination with DOT and EMT?**

A. The Company agreed that it should align its EV activity closely with the Maine Plan for EV Infrastructure Development (PEVID) and should establish shared objectives with Efficiency Maine Trust (EMT) and Maine Department of Transportation (DOT)."[79]

**Q. Did you find the Company's response sufficient?**

A. No. While we appreciate the Company's willingness to coordinate with DOT and EMT, the Company has not identified any specific way it will pursue this coordination. Most notably, the Company did not specify how the availability of NEVI program funds will affect the Maine EV market and the need for utility funding.

**Q. How should the Company's EV programs be adjusted given the availability of other funding sources from EMT and DOT?**

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[79] CMP Rebuttal at 25:3-5.

A. Maine will receive $19.3 million between 2022 and 2026 towards public DC Fast Charging (DCFC) along highways under the NEVI program[80] and may receive some of the $2.5 billion available nationwide under the Charging and Fueling Infrastructure (CFI) Discretionary Grant Program for EV charging in communities and neighborhoods.[81] We recommend that the Company require potential participants of the Light-Duty EV Make-Ready Program to self-report any state and federal funding that is available and applicable, as well as any amount of funding received. The Company should then deduct the state or federal incentive amount the customer has received from the amount eligible through the make-ready program. For example, if a customer is eligible for $20,000 of make-ready incentives under the Company's program but received $15,000 in NEVI funding for make-ready costs, then the Company should provide only $5,000 in make-ready incentives to that customer. A customer's total incentives should not exceed their actual infrastructure costs. Any state or federal funding for equipment not covered by the Company's program (*e.g.*, EV supply equipment) will not be deducted. The Massachusetts Department of Public Utilities recently adopted the same requirement for National Grid and Eversource's make-ready programs.[82] The freed-up program budget

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[80] Federal Highway Administration. *National Electric Vehicle Infrastructure Funding by State.* https://www.fhwa.dot.gov/bipartisan-infrastructure-law/evs_5year_nevi_funding_by_state.cfm

[81] Federal Highway Administration. 2023. "Biden-Harris Administration Opens Applications for First Round of $2.5 Billion Program to Build EV Charging in Communities & Neighborhoods Nationwide." https://highways.dot.gov/newsroom/biden-harris-administration-opens-applications-first-round-25-billion-program-build-ev

[82] Massachusetts Department of Public Utilities. *December 30, 2022 Decision*, pg. 125-128. Dockets D.P.U 21-90, 21-91, 21-92. https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/16827695

can then be stretched further and reach more customers, ultimately resulting in higher levels of charging infrastructure deployment. It will also prevent the use of utility make-ready funds where funding from other sources is available for the same purpose. This change will prevent EV customers from receiving duplicative incentives for the same infrastructure deployment and ensure program dollars are utilized efficiently.

**Q. How did the Company respond to your recommendation to restructure program incentives to cover a percentage of total make-ready costs, rather than only utility-side make-ready costs?**

A. The Company did not agree with my recommendation, arguing that "a cap on incentives towards utility-side make-ready costs would serve as an appropriate cost signal and would dissuade charger development at high-cost locations."[83] The Company also stated that other funding sources administered by EMT, such as NEVI, would provide incentives towards customer costs other than utility-side make-ready.

**Q. Other parties also support focusing the Company's EV programs on utility-side make-ready infrastructure. How do you respond?**

A. In response to feedback from other parties regarding the availability of and potential duplicity from other funding sources, we would like to adjust our recommendation to include only utility-side make-ready infrastructure under the Company's EV programs.

[83] CMP Rebuttal at 28:12-15.

**Q. How did the Company respond to your recommendation to modify incentive levels to prioritize publicly accessible chargers, school buses and transit buses, and chargers and fleets located in disadvantaged communities?**

A. The Company agreed that publicly accessible chargers and chargers located in disadvantaged communities be prioritized.[84] The Company recommended a 10% differential between publicly accessible and non-publicly accessible charging sites and maintained its initial proposal to provide up to 100% incentive for chargers in disadvantaged communities and up to 80% for chargers in other communities.[85] The Company also agreed to utilize the Climate and Economic Justice Screening Tool to identify disadvantaged communities instead of the Company's original definition.

**Q. Has the Company provided sufficient detail on what incentive levels different types of charging sites would be eligible for?**

A. No. While we appreciate the Company's agreement to use the Climate and Economic Justice Screening Tool and support for prioritizing publicly accessible chargers and chargers located in disadvantaged communities, it is still unclear how the Company intends to differentiate incentive levels based on both the public accessibility and location of the charging site. The Company only stated that the program could offer "up to" 100% incentive for chargers located in disadvantaged communities and "up to" 80% incentive for chargers not located in a disadvantaged community. Additionally, the Company did

[84] CMP Rebuttal, at 28.
[85] CMP Rebuttal, at 28-29.

not discuss how it intends to prioritize medium- and heavy-duty fleets that serve disadvantaged communities.

**Q. Which incentive levels do you recommend if the Commission approves the Company's EV programs?**

A. Subject to Commission approval of the overall program, we recommend that incentives under the Light-Duty EV Make-Ready Program be set as percentages of utility-side make-ready costs as follows:

| | Located in a Disadvantaged Community | Not Located in a Disadvantaged Community |
|---|---|---|
| Publicly Accessible | 100% | 80% |
| Not Publicly Accessible | 80% | 60% |

Similarly, incentives under the Medium- and Heavy-Duty EV Make-Ready Program should also be set as percentages of utility-side make-ready costs as follows:

| | Serving a Disadvantaged Community | Not Serving a Disadvantaged Community |
|---|---|---|
| School buses and transit buses | 100% | 80% |
| Other fleets | 80% | 60% |

**Q. How did the Company respond to your recommendation to target 40% of program funds towards disadvantaged communities?**

A. The Company argued against our recommendation by asserting that mandating 40% of the budget be spent in disadvantaged communities is arbitrary and may not have the intended impact of further supporting transportation electrification in a way that benefits disadvantaged communities.[86]

**Q. What are the consequences of not adequately prioritizing disadvantaged communities?**

A. Disadvantaged communities, which tend to be communities of color and low-income communities, have suffered from decades of underinvestment. On the other hand, they also stand to benefit immensely from transportation electrification, including in terms of lower transportation costs as well as reduced air pollution and associated health impacts. However, without dedicated program budget to prioritize disadvantaged communities, the benefits of the Company's EV programs will likely be inequitably distributed since charging infrastructure in disadvantaged communities may be less profitable in the near term when EV adoption in disadvantaged communities is expected to remain low. However, the lack of charging infrastructure in these communities will continue to discourage EV adoption by their residents. Meanwhile, program incentives will continue to flow to non-disadvantaged communities and higher-income households that are more likely to be early EV adopters, despite the fact that utility bill increases disproportionately

[86] CMP Rebuttal, at 29.

burden low-income households.[87,88] This scenario will lead to a future in which higher-income households enjoy the benefits of electrified transportation while low-income households are stuck with the more expensive and polluting gas-powered vehicles.

**Q. Do you agree that your recommendation to target 40% of program funds towards disadvantaged communities is "arbitrary"?**

A. No. Recognizing the historical underinvestment in disadvantaged communities, the Biden Administration has created the Justice40 Initiative to ensure that at least 40% of the benefits of climate, energy, environmental, and housing investments flow to these communities.[89] Our recommendation is intended to mirror this federal goal. Notably, Maine DOT's PEVID also has an aim to deliver at least 40% of EV charging investments in disadvantaged communities, consistent with the Justice40 initiative.[90] The Company has not demonstrated that it faces a different market or customer base than DOT and has not provided any convincing argument on why this target should not apply to its EV programs.

**Q. Do you wish to make any modifications to your original proposal?**

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[87] American Council for an Energy Efficient Economy, *Lifting the high Energy Burden in America's Largest Cities: How Energy Efficiency Can Improve Low-Income and Underserved Communities* (April 20, 2016). https://www.aceee.org/research-report/u1602

[88] Xu, X., & Chen, C.-fei., Energy efficiency and energy justice for U.S. low-income households: An analysis of multifaceted challenges and potential, *Energy Policy* (Feb. 5, 2019). https://www.sciencedirect.com/science/article/pii/S0301421519300205

[89] White House. *Justice40.* https://www.whitehouse.gov/environmentaljustice/justice40/

[90] Maine DOT. *Maine Plan for Electric Vehicle Infrastructure Deployment*, pg. 38. https://www.maine.gov/mdot/climate/docs/pevid-2022.pdf

A. We maintain that at least 40% of the Company's EV program budgets should be targeted towards disadvantaged communities. However, this target can be applied across the totality of the Company's EV programs, including the Light-Duty EV Make-Ready Program, the Medium- and Heavy-Duty EV Make-Ready Program, and any other EV offerings approved by the Commission, rather than to individual program offerings. This will allow the Company some flexibility to adjust its offerings to customer and market demand while still ensuring disadvantaged communities are adequately prioritized. For example, if the Light-Duty EV Make-Ready Program receives insufficient demand from site hosts in disadvantaged communities to meet or exceed the 40% target, the Company can work to increase participation in the Medium- and Heavy-Duty EV Make-Ready Program from fleets, including school buses and transit buses, that serve disadvantaged communities to over 40% so that at least 40% of the overall portfolio is targeted towards disadvantaged communities. As noted above, coordination between EMT and DOT should be required to minimize duplicative efforts.

### (ii) EV Planning Analysis and Activity

**Q. Please summarize your position from direct testimony regarding the Company's EV Planning Analysis and Activity proposal.**

A. We recommended the Commission should consider the development of an EV distribution planning roadmap as part of a broader EV grid modernization proposal outside of this rate case that includes stakeholder input and the following requirements:

- The Company details all the EV planning activities they intend to employ and why, their methodologies and how they expect these planning activities to evolve over the short and long-term

- The Company details how all EV planning activities will be coordinated with the integrated distribution planning process established in Docket No. 2022-00322

**Q. Please summarize the Company's response to your position.**

A. The Company states it is not feasible to identify all activities and methodologies at this time because studies will be iterative and specific methodologies will be developed and offered by external vendors in response to competitive requests for proposals. The Company's goal is to better understand and anticipate the pace of EV market development and expected load profiles of the different types of transportation that will electrify. This increased understanding will help to reduce uncertainty, allow the Company to plan proactively, and become an input to the Company's overall load forecasting process. Prior to commencing any study, the Company will gather input from stakeholders including, but not limited to the GEO, the OPA and EMT, to help inform which area of focus would be most valuable. The Company will also share results from the studies with these stakeholders to inform future iterations.[91]

**Q. What is your response to the Company's position and your recommendations?**

[91] CMP Rebuttal, at 31, 7-17.

A. We appreciate the Company's willingness to conduct an iterative, stakeholder-driven and transparent EV planning process. Given Maine's ambitious clean energy goals, the Company should begin planning for EVs immediately provided a comprehensive approach is taken. Based on these additional details provided by the Company, we recommend the Commission approve the Company's proposal with the following modifications:

- The Company files all initial and future details regarding this program as part of an 'EV Distribution Planning roadmap' as previously recommended. The roadmap would serve as a living document that would be iterated upon over time in collaboration with stakeholders as EV needs evolve in Maine.
- The Company files all initial and future details as well as solicits stakeholder feedback regarding this program in the comprehensive EV proceeding recommended in Section VI(A)(i). Activities include but are not limited to filing initial details on the program, soliciting stakeholder feedback, sharing results of studies and iterating on the Company's EV planning activities.
- The initial EV Distribution Planning roadmap should also include a proposal to develop and publish EV hosting capacity maps, in addition to vehicle adoption and load impact forecasts, as part of the studies and analysis conducted. We note

that United Illuminating has already published EV hosting capacity maps in Connecticut as of Q3 of 2022 which can inform the Company's proposal.[92]

- The initial EV Distribution Planning roadmap should detail how all EV planning activities will be coordinated with the integrated distribution planning process established in Docket No. 2022-00322.

### (iii) Future EV Programs

**Q. Please summarize your position from direct testimony regarding other EV related issues.**

A. We recommended the Commission consider the development of an EV distribution operations and architecture roadmaps as part of a broader EV grid modernization proposal. As part of the EV distribution operations roadmap, we recommended the Company develop an EV load management plan starting with implementing Managed charging and Automated Load Management ("ALM"). We also recommended the Company, through the broader ARD process outlined, above, develop sufficient rate design options.

**Q. How did the Company respond to your recommendations related to managed charging and ALM/EV EMS?**

[92] PURA, Docket No. 17-12-03-RE04, Proposed Plan to Develop Hosting Capacity Map, at 1-2.

A. The Company did not respond to our recommendations regarding an EV distribution operations and architecture roadmaps or rate design. However, the Company did respond regarding our managed charging and ALM. The Company agreed that these technologies "will play an important role in managing future EV load" but argued that they are "still in their infancy and standards and protocols have not yet been developed."[93] The Company also states the development utilization of managed charging and ALM should be further explored and developed as pilot projects with the learning from those pilots used to inform and make recommendations for scaled deployment.[94]

**Q. Is the Company's characterization of managed charging and ALM/EV Management System (EMS) accurate?**

A. No. The Company's statement demonstrates a severe lack of understanding of the state of EV load management technologies and programs and shows that the Company has not sufficiently prioritized strategies to mitigate ratepayer costs in relation to EV charging. In fact, managed charging and ALM/EV EMS offerings for both residential and commercial EV customers have been developed and implemented by many utilities all around the country.

EV Load management will be critical to cost-effectively electrifying the transportation sector. A NYSERDA study estimated distribution system upgrade costs due to transportation electrification range from $1.4 billion in the Low-Distribution

[93] CMP Rebuttal, at 30:12-14.
[94] CMP Rebuttal, at 30, 12-17.

System Impact ("LDI") Managed EV charging case to $26.8 billion in the High-Distribution System Impact ("HDI") Unmanaged case. It can be observed from the results that the distribution upgrade costs were significantly lower with managed EV charging—61 percent and 46 percent of the unmanaged case for HDI and LDI scenarios, respectively, showing that managed charging could play a signification factor in lowering the distribution upgrade costs.[95] Thus, the Company should be required to prepare for EV load management upfront as part of implementing an initial set of EV programs.

**Q. Can you provide some examples of utilities providing managed charging offerings to EV customers?**

A. There are a variety of approaches to managed charging for EVs. Passive managed charging programs focus on altering customer behavior through rate design or other financial incentives. These offerings can include simple time-of-use rates; more advanced rates like critical peak pricing (*e.g*, Xcel Colorado's EV Critical Peak Pricing rate[96]) or dynamic rates (*e.g.*, San Diego Gas & Electric's Electric Vehicle Grid Integration Pilot Program[97]); as well as programs that provide customers with per kWh or monthly

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[95] NYSERDA, Transportation Electrification Distribution System Impact Study, https://www.nyserda.ny.gov/-/media/Project/Nyserda/Files/Publications/Research/Transportation/22-13-Transportation-Electricification-Distribution-System-Impact-Study.pdf, at 49

[96] Xcel Energy, EV Critical Peak Pricing Information Sheet (2021) https://www.xcelenergy.com/staticfiles/xe-responsive/Programs%20and%20Rebates/Business/EV-CPPInfo-Sheet.pdf.

[97] San Diego Gas & Electric, Schedule VGI (2017) https://www.sdge.com/sites/default/files/elec_elecscheds_vgi.pdf.

incentives for charging during off-peak periods and avoiding on-peak charging (*e.g.*, Con Edison's SmartCharge NY Program[98]).

Unlike passive managed charging programs, active managed charging programs utilize communication/dispatch signals from a utility or aggregator to control EV charging in a predetermined manner, and thereby unlock a greater level of flexibility of EV load. Active managed charging programs can use a demand response approach (*e.g.*, National Grid's and Eversource's EV Active Demand Reduction Program[99]) to throttle EV charging during demand response events or use continuous management to align EV charging with hours of low power production costs (*e.g.*, Xcel Colorado's Charging Perks Pilot[100]) or low greenhouse gas emissions (*e.g.*, Orange & Rockland's Charge Smart Program[101]). A more comprehensive list of managed charging programs can be found in the Smart Electric Power Alliance's The State of Managed Charing in 2021 Report.[102]

**Q. Have the Company's sister utilities pursued managed charging?**

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[98] New York State Department of Public Service, Case 18-E-0138 (ConEdison EV Managed Charging Filing) (2020). https://documents.dps.ny.gov/public/MatterManagement/MatterFilingItem.aspx?FilingSeq=256901&MatterSeq=56005

[99] Three-Year Energy Efficiency Plan 2019-2021, DPU 18-110 - 18-119, Exh. 1, Appendix K, available at https://ma-eeac.org/wp-content/uploads/Exh.-1-Final-Plan-10-31-18-WithAppendices-no-bulk.pdf.

[100] Xcel Energy Colorado, 2021/2022 Demand-Side Management Plan, at 263-65 (2021). https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/Regulatory%20Filings/CO-DSM/CO_2021-22_DSM_Plan_Final.pdf.

[101] 3 Orange & Rockland, Charge Smart Program (2020) https://ny.myorustore.com/content_charge_smart_program.html.

[102] Smart Electric Power Alliance. 2021. *The State of Managed Charging 2021*. https://sepapower.org/resource/the-state-of-managed-charging-in-2021/

A. Yes. Several other Avangrid utilities are currently in the process of implementing or have implemented managed charging programs. In July 2021, the Connecticut Public Utilities Regulatory Authority ordered United Illuminating and other Connecticut utilities to establish a Managed Charging Working Group to develop programs for residential and commercial EV customers.[103] In July 2022, the New York Public Service Commission approved New York State Electric & Gas and Rochester Gas & Electric's managed charging program for residential EV customers, which was built upon the two utilities' previous pilots.[104]

**Q. Can you provide some examples of utilities implementing ALM/EV EMS?**

A. Yes. Pacific Gas & Electric (PG&E) has worked with EV service providers to implement ALM solutions at multi-unit dwelling and workplace host sites as of Q4 2020 and saved between $30,000 and $200,000 per project.[105] Southern California Edison also implemented ALM to deploy 168 charging stations at $3,000 per port, significantly less than comparable deployments at $10,000-$15,000 per port without EV EMS.[106]

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[103] CT PURA, Docket No. 17-12-03RE04, Investigation into Distribution System Planning of the Electric Distribution Companies – Zero Emission Vehicles, Decision, at 15-16. https://portal.ct.gov/-/media/PURA/electric/PURA-Establishes-Statewide-Electric-Vehicle-Charging-Program.pdf

[104] New York Public Service Commission, Order Approving Managed Charging Programs with Modifications (2022). https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={A1E3F84E-0710-4073-865F-FE7D4816B76B}

[105] Pacific Gas & Electric, Presentation at CPUC ALM/EV EMS Workshop, Panel 2 (2021).

[106] EPIC Policy + Innovation Coordination Group, Transportation Electrification Workstream Report, pg. 12 (2021) https://epicpartnership.org/resources/Transportation_Electrification_Workstream_Report_Final.pdf.

Following these successful experiences, as part of PG&E's 2021 proposal for an EV make-ready program, the California utility included a standard evaluation methodology that would be applied to all charging sites during preliminary site design to determine if ALM can be used to cost-effectively meet the customer's charging needs.[107] The California Public Utilities Commission has adopted this proposal, stating that this strategy will "help lower program costs and promote efficient use of electric grid infrastructure.[108]

In Massachusetts, the Department of Public Utilities recently directed National Grid and Eversource to perform case-by-case evaluation of the cost effectiveness of EV EMS for certain EV charging customers as part of the utilities' EV infrastructure programs.[109] Similarly, the Illinois Commerce Commission recently required Commonwealth Edison and Ameren to implement EV EMS pilots as part of the utilities' EV programs.[110,111]

**Q. Do you have updates to your recommendations?**

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[107] PG&E, Electric Vehicle Charge 2 Prepared Testimony, Chapter 5, Attachment A, Case Number A.21- 10-010 https://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=675449.

[108] California Public Utilities Commission. *Decision Authorizing Pacific Gas and Electric Company's Electric Vehicle Charge 2 Program,* pg. 54. Case Number A.21-10-010. https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M500/K043/500043974.PDF

[109] Massachusetts Department of Public Utilities. 2022. *Decision, p*g. 103-104. Dockets D.P.U 21-90, 21-91, 21-92. https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/16827694

[110] Illinois Commerce Commission. 2023. *Case 22-0432 Order*, pg. 88. https://www.icc.illinois.gov/docket/P2022-0432/documents/335467/files/584484.pdf

[111] Illinois Commerce Commission. 2023. *Case 22-0431 Order*, pg. 119. https://www.icc.illinois.gov/docket/P2022-0431/documents/335471/files/584490.pdf

A. We recommend that the Commission require the Company to develop and file an EV Grid Operations and Architecture roadmap within 90 days of an Order in a comprehensive EV proceeding, Docket No. 2022-00322 or another appropriate proceeding as determined by the Commission. The roadmap should include an EV load management plan which at a minimum should include proposals to implement 1) managed charging across their service territory, 2) a pilot program for ALM and 3) a metering or alternative (e.g., submetering or telematics) approach for implement EV rate designs. The Company's managed charging proposal should include both passive and active managed charging offerings and should address both residential and commercial EV customers. The Company's ALM pilot proposal should include developing a standard site evaluation methodology for all EV charging sites to inform customers of the cost-saving potential of ALM. The Company's metering proposal should consider all types of metering devices including utility meters, EV chargers and EV telematics.

We also continue to recommend the Company establish dedicated resources to implement all future EV programs. We recommend the Commission require the Company to file an EV staffing plan, including roles and responsibilities, within 30 days of an Order in a comprehensive EV proceeding, Docket No. 2022-00322 or another appropriate proceeding as determined by the Commission. This plan should detail how the Company intends to establish a dedicated EV team to implement the Make-Ready, EV Planning Analysis and Activity and Future EV programs.

## B. Grid Model Enhancement Project (GMEP)

**Q. Please summarize your position from direct testimony regarding the Company's GMEP proposal.**

A. Prior to Commission approval of the GMEP, we recommend[ed] the Company detail what methodologies and technologies will be used to implement the GMEP.[112] We also recommend[ed] the Company investigate leveraging a machine-learning based Digital Twin to implement the GMEP in a sustainable and scalable manner.

**Q. Please summarize the Company's response to your position.**

A. The Company states they do not believe that the technologies to accomplish the GMEP must be fully planned out before the project is approved, that the GMEP is currently in the project planning stage and that CMP and its affiliates in New York have engaged with specialized vendors for conducting pilot field surveys on some limited distribution areas to evaluate the best available technologies.[113] The Company also states they are willing to investigate the potential costs and benefits associated with the machine-learning digital twin and automation technologies proposed by Strategen on a going forward basis, [but] is not proposing to incorporate the digital twin technology into the GMEP at this time [which provides] the Company the flexibility to incorporate the best technology to accomplish the task and address the need is appropriate.[114]

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[112] ME GEO Direct Testimony, at 88
[113] CMP Rebuttal, at 14.
[114] CMP Rebuttal, at 14.

**Q. What is your response to the Company's position?**

A. Given that the Company is currently conducting field surveys to evaluate the best technologies, we agree that GMEP does not need to be fully planned out before the project is approved. However, the Commission should establish high-level parameters and reporting requirements the Company should follow to ensure that the GMEP is implemented in a sustainable and scalable manner while providing benefits to ratepayers as soon as possible. Specifically, the Commission should require the Company to 1) investigate a digital twin as parts of its technology evaluation for implementing the GMEP, 2) implement the GMEP on an iterative, regional basis within its service territory and 3) provide periodic updates on the implementation of the program.

**Q. Why is not cost-effective to evaluate the GMEP on a going forward basis?**

A. While we appreciate the Company's willingness to investigate a digital twin on a "going forward" basis, it is not cost-effective to evaluate this technology separately but rather as part of the comprehensive evaluation currently being conducted. Multiple technologies might be warranted to implement and maintain the GMEP in the long run and thus all the available technologies, including the digital twin, should be investigated upfront. For example, the Company may need to choose a more manual approach for the initial implementation of the GMEP to establish a baseline for their system. Once this is complete, the Company could input this information into a digital twin after which updates to the electric system model would be done automatically based on the latest system data. To be clear, we are not recommending the digital twin necessarily be implemented immediately but evaluated as both a short and long-term technology option to implement the GMEP.

**Q. What are the benefits of implementing the GMEP on an iterative, regional basis?**

A. Implementing the GMEP across the Company's entire service territory is a worthy but potentially time-consuming undertaking given the complexity of the distribution system and should be done so in a way that yields benefits as quickly as possible. Given Maine's ambitious climate goals, the GMEP should be implemented strategically such that certain locations on the Company's distribution system are prioritized and once complete are operationalized into planning and operations immediately. For example, the Company could prioritize substations and corresponding feeders with large interconnection queues, significant forecasted load growth (ex: locations identified in NEVI plan) and historical reliability issues. Once the GMEP is implemented in these locations, the Company can immediately incorporate this information into planning and operations and have a better sense of the system assets and conditions which can lead to faster interconnections and more informed investments to improve reliability.

**Q. Why are periodic updates on the implementation of the program important?**

A. Periodic updates provides transparency and accountability into the implementation of the program. The Commission and stakeholders should have visibility into the GMEP implementation plan including 1) what technologies the Company is evaluating and any justifications for technologies selected and 2) any prioritizations of locations where the GMEP will be implemented and the associated timelines for implementation.

**Q. What is your recommendation for the proposed GMEP?**

A. We recommend the Company 1) investigate a digital twin as parts of its technology evaluation for implementing the GMEP, 2) implement the GMEP on a iterative, regional basis within its service territory, prioritizing areas with relatively larger interconnection queues, significant forecasted load growth, historical reliability issues and any other factors the Company proposes and 3) provide periodic updates via an annual compliance filing on the implementation of the program including what technologies the Company is evaluating and any justifications for technologies selected, any criteria for prioritizing locations where the GMEP will be implemented and the associated timelines for implementation and realization of benefits.

## C. CMP Innovation Pilots, Partnerships and Collaborations

### i. UMaine Collaboration

**Q. Please summarize your position from direct testimony regarding the Company's UMaine Collaboration proposal.**

A. We [took] no position on the reasonableness of the Company's and UMaine's collaboration.[115] However, we expressed three concerns with the proposal: 1) the Company appears to be solely responsible for determining what innovative products and services will be tested, 2) the lack of clarity regarding stakeholder input and collaboration

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[115] ME GEO Direct Testimony, at 91.

beyond academic institutions, and 3) the likelihood that scalable solutions will be created through the proposed framework.[116]

Regardless of the Commission's action on the Company's proposal, we [stated] the need for a broader, more structured platform for innovation.[117] As a starting point, we recommend[ed] the Commission investigate the development of Innovative Energy Solutions (IES) program whereby innovative pilot programs, technologies, products, and services can, on a limited basis, be deployed, investigated, and evaluated for overall impact, costs, and benefits, and scaled if ratepayer benefits are demonstrated.[118] Additionally, we recommend[ed] the Commission investigate establishing an independent governance comprised of a diverse set of stakeholders to implement the IES program.[119]

**Q. Please summarize the Company's response to your position.**

A. The Company sees value in creating a program similar to Connecticut's Innovative Energy Solutions ("IES") program, [but expressed concerns that] it seems likely that the program design, development, and launch would take multiple years to complete based on the experience with Connecticut's IES program.[120] The Company sees [their proposal] as the first step in facilitating essential research and development which will benefit

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[116] ME GEO Direct Testimony, at 90.
[117] ME GEO Direct Testimony, at 91.
[118] ME GEO Direct Testimony, at 91.
[119] ME GEO Direct Testimony, at 91.
[120] CMP Rebuttal Testimony, at 49.

customers.[121] The Company goes on to state this initial collaboration effort should not be delayed, but it can feed into a broader, more structured platform for innovation in Maine that can be developed with more time and process.[122]

The Company also responded to the three concerns we identified. In response to my first concern, the Company states they are well positioned to identify opportunities to advance specific grid and/or customer needs that can be addressed by research innovative pilots and demonstrations [but] are committed to engaging in a process to solicit and obtain stakeholder feedback.[123] In response to the second concern, the Company proposes stakeholder engagement process to implement the UMaine Collaboration.[124] In response to the third concern, the Company states scalability should not be a concern as one of the objectives of a pilot is to explore whether the particular approach would be scalable.[125]

**Q. What is your response to the Company's position?**

A. We continue to emphasize the need for a broader, more structured platform for innovation like Connecticut's IES program, of which the Company acknowledges the value. While we agree the Company has critical expertise that is needed when identifying innovation opportunities, we continue to have concerns about the 1) Company being solely responsible for determining the pilot and research priorities, 2) stakeholder input

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[121] CMP Rebuttal Testimony, at 49.
[122] CMP Rebuttal Testimony, at 49.
[123] CMP Rebuttal Testimony, at 49.
[124] CMP Rebuttal Testimony, at 50.
[125] CMP Rebuttal Testimony, at 50-51.

and collaboration in the proposed program and 3) scalable solutions emerging from the proposed program.

**Q. Please further explain your first concern.**

A. The Company has an inherent financial and operational bias that may limit the potential innovation opportunities in Maine if they are solely responsible for determining pilot and research priorities.

For example, from a financial perspective, the Company has a disincentive to accommodate DERs due its capital bias, even when DERs meet customer needs at a lower cost. The Company does not currently have any performance metrics that would incentivize interconnection of DERs, or maximizing their utilization ,whether by avoiding curtailments or leveraging them for grid services. Until an interconnection performance metric is established to address incentivize outcomes as required by LD 1959, the current incentive structure could limit the opportunities for innovative pilots that accelerate DER integration and utilization.

From an operational perspective, utilities are typically risk averse and have not traditionally been required to rapidly innovate. Innovative solutions to energy and grid challenges are often trapped in pilot after pilot with no clear path to scaled deployment.[126] One example where significant innovation will be required is the modernization of the distribution system at scale to enable a decentralized grid with a high penetration of

[126] Grid Modernization Laboratory Consortium, The Role of Innovation in the Electric Utility Sector, at 82

DERs. What was traditionally an analog grid with a limited need for data now must be digitized leveraging the latest innovations in sensor, computing, communications, and software technologies to make granular planning and operational decisions to integrate and utilize DERs. These capabilities are emerging technologies and require independent perspectives and proposals from the market.

However, if the Commission decides to approve the Company's proposal, we recommend the Commission adopt our modifications to the Company's proposed stakeholder process and scalability framework as described below and use the lessons learned from this program to inform the Commission's investigation into a program similar to Connecticut's IES.

**Q. Please further explain your second concern.**

A. While we appreciate the Company providing additional details on the proposed stakeholder engagement process, we propose additional modifications to the Company's proposal. Specifically, the Company should issue request for proposals (RFPs) to allow academic institutions and third-party innovators to submit their own innovation proposals to inform the Company's selection of innovation opportunities.

**Q. Please further explain your third concern.**

A. We agree with the Company that one of the objectives of a pilot is to explore whether the particular approach would be scalable.[127] To do this, a framework is needed to determine

[127] CMP Rebuttal Testimony, at 51.

whether a pilot would be scalable and how to deploy and integrate such pilot as part of the Company's normal operations. If the Commission were to approve this program, the Company should work with stakeholders to develop this deployment and integration framework upfront to determine how successful pilots will be integrated into regular planning and operations, where could pilot costs could be integrated, and how costs would be recovered.

**Q. What is your recommendation for the proposed UMaine Collaboration?**

A. We continue to take no position on the Company's proposal and recommend the Commission investigate the development of Innovative Energy Solutions (IES) program whereby innovative pilot programs, technologies, products, and services can, on a limited basis, be deployed, investigated, and evaluated for overall impact, costs, and benefits, and scaled if ratepayer benefits are demonstrated. We recommend the Commission investigate the development of an IES-type program in Docket No. 00322 or another appropriate proceeding.

If the Commission approves the Company's proposal, we recommend the 1) Company should issue request for proposals (RFPs) to allow academic institutions and third-party innovators to submit their own innovation proposals to inform the Company's selection of innovation opportunities, 2) work with stakeholders to develop this scalability framework upfront to so that pilots can be expeditiously evaluated for scalability and rapidly scaled where appropriate and 3) that lessons learned from this proposal be used to inform the Commission's investigation into an IES-esque program.

### ii. Active Network Management (ANM) Pilot

**Q. Please summarize your position from direct testimony regarding the Company's ANM proposal.**

A. We recommend[ed] that the approval of the ANM pilot be contingent upon the Company developing a plan for scaling flexible interconnection and/or export-based tariff schemes prior to and contingent with the pilot. First, the Commission should order the Company to begin enabling flexible interconnection schemes for DERs seeking to interconnect. Specifically, the Commission should initiate a process (this could be a series of technical sessions or a working group that includes the relevant industry stakeholders) by which the Company would be required to implement flexible interconnection service options into interconnection tariffs.

**Q. Please summarize the Company's rebuttal response to your position.**

A. The Company states it is not appropriate to condition the commencement of the Pilot on a requirement to adopt a plan before the results of the Pilot are in.[128] The Company states they are proposing the ANM Pilot to determine whether this is a technology solution that can be effectively, beneficially, and more broadly implemented and that the results of the Pilot are expected to inform a plan for scaling flexible interconnections.[129] The Company

[128] CMP Rebuttal Testimony, at 23.
[129] CMP Rebuttal Testimony, at 23.

also states it is not appropriate to condition approval of the ANM "head-end" system on a plan to implement an export-based tariff scheme[130] due to existing cost structures.

**Q. What is your response to the Company's rebuttal position?**

A. ANM has several objectives including serving as a cost-effective alternative compared to some traditional 'wires' modifications, increas[ing] a circuit's DER hosting capacity enabling the cost effective interconnection of additional clean, renewable resources and enabl[ing] improved asset utilization by enabling the interconnection of additional DER without the need to increase asset capacity.[131] As previously mentioned, flexible interconnection is the broader term associated with achieving these objectives and ANM is one type of flexible interconnection. As previously mentioned, flexible interconnection is a critical tool to cost-effectively integrating DERs that has been proven in other countries and jurisdictions. If the Company is going to propose a pilot to achieve these objectives, the pilot should evaluate the full suite of flexible interconnection options including ANM to achieve these objectives. This pilot should evaluate both the technical and economic feasibility of flexible interconnection testing flexible interconnection options such as ANM and volt-watt and export-based tariff schemes. We agree with the Company that a plan to scale flexible interconnection can only be developed once the results of the pilot are complete. Thus, if the pilot is successful, the Company should be required to develop a plan to scale interconnection.

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[130] CMP Rebuttal Testimony, at 23.

[131] CMP Direct Testimony, Grid Modernization, at 29.

**Q. What are your recommendations?**

A. We maintain our recommendations from direct testimony but modify the sequence in which they should be implemented. We recommend the Company's proposal be broadened to pilot not just ANM but flexible interconnections options more broadly. The Company should submit a detailed flexible interconnection pilot proposal which includes the following:

- Implementation plans for piloting flexible interconnection schemes including at a minimum volt-watt and ANM
- Implementation plans for piloting export-based tariff schemes in tandem with the volt-watt and ANM pilots
- Proposed metrics for tracking the performance of volt-watt and ANM pilots and the corresponding export-based tariff schemes

The Commission should solicit stakeholder feedback on the Company's proposal and modify as appropriate. Once approved, the Company should file annual compliance filings on the progress of the pilots. Upon completion of the pilots, if one or more pilots were successful, the Company shall file a plan to scale one or more flexible interconnection schemes across its service territory.

## VII. Conclusion

**Q. Does this conclude the panel's surrebuttal testimony?**

A. Yes.