Technical Review of the Analysis Provided in the Integrated Resource Plan of Central Maine Power

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1 EXECUTIVE SUMMARY

Purpose and Scope

In Docket 2022-00322, the Maine Public Utilities Commission (MPUC) directed Central Maine Power (CMP) and other Maine utilities to develop a 10-Year Integrated Grid Plan (IGP). The IGP is intended to provide a forward-looking assessment of grid capacity needs and potential solutions to accommodate projected load growth, increased electrification, and distributed energy resources (DER) integration in support of Maine's climate goals. The Order outlined three priorities: reliability, data quality and integrity, and flexible load management. This document summarizes the findings of a technical review of CMP's December 2025 IGP filing, assessing the quality of CMP's engineering analysis, compliance with Commission requirements, and conformance with utility best practices.

About CMP

CMP is Maine's largest electricity transmission and distribution utility, serving approximately 670,000 customers across an 11,000-square-mile service area in central and southern Maine with a system peak demand of 1,745 MW. CMP is a subsidiary of Avangrid and operates solely as a wires utility — it owns no generation — within the ISO-NE regional grid under MPUC and FERC oversight. CMP faces challenges from increased demand from electrification, DER growth, and Maine's 2040 decarbonization goals. These trends are major contributors to the utility moving from summer to winter peaking. The service territory is geographically dispersed with significant tree cover, presenting growing reliability challenges as climate-fueled extreme weather events increase across the U.S. This geographic spread presents planning and operational challenges distinct from those of utilities with smaller footprints and larger customer concentrations.

Summary of CMP's Methodology

CMP developed the required 12 study cases using load levels derived from the ISO-NE CELT 2024 forecast, extrapolating values to the 10-year target year of 2034. CMP also developed six additional transmission scenarios to analyze high and low import flows from Canada — a practice consistent with sound transmission planning and applicable reliability standards. This scope is appropriate for scenario-level planning to identify thermal overloads and voltage problems, though it does not substitute for the more comprehensive stability and short-circuit analysis typically conducted for individual capital projects.

Based on its analysis, CMP identified violations across 16 categories — distinguishing between transmission and distribution needs, near-term and long-term needs, thermal and voltage issues, and DER-driven needs. CMP then identified representative solutions for each category across four broad approaches:

- Load shifting and network reconfiguration
- Peak shaving and load management
- Upgrades to existing equipment
- Build new infrastructure

Solutions were evaluated using the DOER-developed scorecard adopted by the MPUC, which assesses each solution across four dimensions: 1) Cost, 2) Technical Performance, 3) Environmental Justice, and 4) Policy Alignment, along with an Overall Score. CMP provided illustrative case studies for a representative sample of 70 circuits and extrapolated findings to provide a system-wide investment estimate but did not provide for specific violations.

Areas for Improvement

CMP's analysis is broadly consistent with good utility practice for scenario-level planning and meets the requirements of the Order; however, several areas fall short of best practice or warrant greater attention:

- Regulatory barriers to BESS and Non-Wires Alternatives (NWAs): CMP identified barriers related to cost recovery, ownership, and regulatory classification but did not outline a plan or advocacy strategy to address them.
- Load model disaggregation methodology: CMP adjusted individual load buses to reflect localized growth trends but did not fully document the method, limiting independent replication. Additional details would improve transparency and support independent analysis.
- Battery energy storage systems (BESS): Although BESS was identified as a preferred or alternate solution in 9 of 16 scorecard categories, CMP treats it primarily as a pilot concept rather than a standard planning option. An economic evaluation framework comparing BESS to conventional solutions is needed.

Data, Mapping, and Systems Deficiencies

The review identified significant deficiencies[1] in CMP's data infrastructure that limit the effectiveness of current and future planning:

- Distribution system maps are noted as inaccurate or incomplete in portions of the service territory. CMP has 69 distribution lines exceeding 100 miles in length — including one of 250 miles — which is highly unusual. An ongoing remediation effort is underway, but governance and pace of improvement require attention.
- CMP indicates that it lacks the tools and data integration required to perform time-series analysis at the circuit and feeder level. Planning relies heavily on manual data processing, limiting the frequency of hosting capacity map updates and the granularity of system need identification. To manage increasing distributed solar, electric vehicles (EVs) and electrification of load, utilities with similar challenges are adopting planning practices with quasi static time series analysis that may be incorporated into capital planning in the future,
- Advanced metering infrastructure (AMI) and SCADA data are not yet fully integrated into CMP's planning software platforms (e.g., CYME), limiting CMP's ability to leverage smart grid data for enhanced planning to identify more opportunities for low-cost innovative

[1] In this context, deficiencies are not in reference to the requirements of the IGP, but in the context of utility practices typical of distribution system planning.

solutions. It is noteworthy that CMP was an early adopter of smart meter technology with more than a decade of operational experience.

Recommendations

CMP's IGP addresses the requirements of the MPUC Order, and the identified shortfalls do not rise to the level of formal deficiency. Significant opportunities for improvement remain, particularly in the following areas. The following recommendations are directed at closing those gaps:

1. Accelerate Advanced Load Forecasting and Time-Series Analysis

CMP should implement its Advanced Load Forecasting initiative without delay and develop a detailed implementation plan with specific milestones, measurable progress metrics, and risk mitigation strategies. Integration of time-series analysis at the customer level will improve grid planning accuracy and support faster DER interconnection, thus allowing greater opportunity for customer savings.

2. Develop a Roadmap for Integrating Data Technology into Annual Planning

CMP should specify how and when data enhancement initiatives — including ADMS, DERMS, AMI integration, and SCADA analytics — will be incorporated into annual planning. Milestones should link explicitly to planning workflows so that investment benefits are reflected in capital project selection.

3. Develop a Plan to Address Regulatory Barriers to Flexible Operations

CMP should identify specific barriers to BESS and NWA deployment, distinguishing between those it can address independently and those requiring external action. For each barrier, CMP should identify responsible parties, outline alternative approaches, and describe planned advocacy or coordination steps.

4. Establish Specific, Measurable Targets for IGP Initiatives

CMP should set quantifiable targets for each initiative in Section 8, replacing status updates with performance benchmarks. Future filings should document actions taken since the prior IGP and any steps needed to maintain progress, enabling the Commission and stakeholders to objectively track CMP's advancement.

As Maine accelerates toward its clean energy future, the Maine 2040 Pathways study makes clear that electrification of transportation, heating, and industry — combined with widespread deployment of DERs — will fundamentally reshape load patterns and power flows across Maine's grid, driving substantial transmission and distribution (T&D) investment in the years ahead. Shifting flexible loads and greater adoption of DERs is identified as a key strategy to reducing the cost of T&D infrastructure and supply resources. Traditional planning approaches built around predictable, unidirectional load growth are no longer adequate. Evolving toward integrated, data-driven distribution planning frameworks that explicitly account for DER adoption, electrification scenarios, and locational hosting capacity is essential to ensuring that grid investments are targeted, efficient, and durable — and to achieving the priorities outlined in the Order.

2 SUMMARY OF WHAT TECHNICAL DETAILS AND ANALYSIS THE COMMISSION REQUIRED IN DOCKET 2022-00322

In Docket 2022-00322[2], the Maine Public Utilities Commission (MPUC or Commission) required its utilities to perform analysis and develop a 10-year horizon Integrated Grid Plan (IGP). The Order outlined three priorities: reliability, data quality and integrity, and flexible load management. The Commission required the analysis for 12 scenarios and that it is based on the ISO-NE CELT 2024 Report.[3] The required scenarios cover six seasonal load snapshots for both 90/10 and 50/50 weather years.

The Commission stated that the multi-scenario approach would ensure a broad range of load levels and seasonal conditions are considered, that the CELT captures increased electrification, and that analyzing multiple futures reduces inherent forecasting uncertainty. The Commission recognized that the requirement for a 10-year plan would not reach 2040, which is the target date for Maine to achieve its power sector decarbonization goals.[4] To address this concern, the Commission directed utilities to provide a narrative explanation to describe how it would support the achievement of the climate goals.[5]

The Commission directed utilities to identify grid needs and solutions, requiring analysis of available emerging technologies to enable load management and flexible operation, and to consider cost-effective near-term investments.[6]

For the identified solutions, the Commission required utilities to employ a scoring framework and to include a narrative explanation of the scorecard contents.[7] The scorecard was proposed by the Maine Department of Energy Resources (DOER) and adopted by the MPUC for use for the purpose of consistency across the utilities. The scorecard covers four categories: Cost, Technical Performance, Environmental Justice and Policy Alignment, and Overall Score.

[2] MPUC Docket 2022-00322, MAINE PUBLIC UTILITIES COMMISSION, Proceeding to Identify Priorities for Grid Plan Filings, July 12, 2024

[3] 2024 CELT Report, 2024–2033 Forecast Report of Capacity, Energy, Loads, and Transmission, published by ISO-NE - *In producing the grid plans, the utilities must use two different forecasts, each derived from the most recent CELT (i.e., the 2024 CELT released May 1, 2024), the 50/50 weather year and the 90/10 weather year, and consider six different seasonal load snapshots of each forecast as described in the Outline (see Outline Section 3).*

[4] Maine requires economy-wide carbon neutrality by 2045.

[5] MPUC Order at page 27, *"While the first grid plans will not reach 2040, the Commission also directs the utilities to include a narrative explanation in the grid plans of how they intend to support the achievement of the State's climate goals in subsequent planning periods."*

[6] MPUC Order at page 28, and *"must include "analysis of available and emerging technologies necessary to enable load management and flexibility" as well as "an identification of cost-effective near-term grid investments and operations needed to achieve the priorities identified" in this proceeding."*

[7] MPUC Order at page 30, *"The utilities are directed to complete this scorecard template, plus a narrative explanation of the scorecard contents, as the "minimum requirements" for the solutions evaluation portion of their grid plans."*

In addition to the identification of system needs and solutions, the commission also required that utilities provide a description of its current planning practices and summary of system needs and specifically to address progress on time-series modeling as an important tool in grid planning to support the state's climate goals.[8] While the Order did not specify particular technology preferences, the intent is to deploy technologies that enable DER integration, improve utilization of the existing grid, and reduce Maine's contribution to the regional network service charge through peak shaving and load shifting.

3 SUMMARY OF WHAT CMP PROVIDED IN THE IGP TO MEET THE REQUIREMENTS OF MPUC DOCKET 2022-00322 ORDER

CMP performed engineering analysis consistent with industry practices for evaluating transmission and distribution systems. The process comprises three basic steps: base case development, contingency analysis, and solution development.

a. Power Flow Study Cases

CMP developed 12 study cases with total system load derived from the ISO-NE CELT 2024 system wide forecast, as required by the MPUC Order. Because the ISO-NE 2024 CELT forecast only extends to 2033, CMP appears to have extrapolated the 2033 summer and 2033/34 winter values to derive the total system load for the target year of 2034. The load forecast applied by CMP for the target year is reasonable and consistent with the trend in the 2024 CELT load forecast. From this basis, CMP then applied multipliers to total system forecasted demand to represent the required seasonal snapshots described in the Order. Exhibit 3.1 (page 50) summarizes the percentage applied to the CELT derived load forecast. From this system wide peak, CMP then disaggregated the total amount to just the state of Maine, then further reduced the total Maine state load to represent CMP's portion of the load.

CMP explains that it then adjusted the individual load buses in the model to capture the variation in the load growth trends between distribution substations, though the method used to determine which buses to adjust and by how much is not documented in the IGP. Assessment of individual distribution feeders for 10-year load growth typically blends historical data review with engineering judgment based on local knowledge. Peak loading remains a primary driver of future system needs, while off-peak needs under high DER deployment tend to be more location-specific. For example, a lightly loaded circuit in a rural area with high DER penetration on a sunny spring day may experience reverse power flows.

In addition to the twelve core scenarios required by the Order, CMP developed six additional study scenarios to analyze transmission flows under different interface scenarios: one reflecting high north-to-south flows representative of elevated Canadian imports, and one reflecting low import

[8] MPUC Order at page 30, *"The utilities must provide information on current practices and a summary of system needs. This includes information available that relates to the utilities' initial Climate Change Protection Plans completed pursuant to Section 7 of the Act (now codified at 35-A M.R.S. § 314615), time-series modeling progress and utilization, and a discussion of the utilities current practices' alignment with achieving the State's GHG emissions reduction and climate goals."*

conditions. These additional scenarios are consistent with sound transmission planning practices and conform to applicable reliability planning standards. The study cases that CMP applied are summarized in Exhibit 3.2 (page 51) of the IGP.

b. Analysis

CMP performed power flow analysis on the entire system that included normal operations (n-0), loss of a single facility (n-1) and sequential loss of two facilities (n-1-1) contingency analysis. Short circuit studies and stability analysis were not listed as included. This scope is customary for scenario planning and provides a broad indication of the magnitude and type of system needs. For specific capital project planning, particularly at the transmission level, the analysis would encompass a more comprehensive range of planning studies. Considerations for aging infrastructure and potentially other system needs could also be incorporated.

At the distribution level, CMP considered that some areas on its system may be growing faster than others and experiencing DER growth and load demand growth at different rates. CMP provided an example where three substations on its system (Bishop Street, Bristol and Bucksport) have different projected trends of load growth.[9] Using engineering judgment informed by historical data and local knowledge of development potential is standard practice for distribution load forecasting. CMP did not provide details of the disaggregation of the transmission level loads to the distribution substations and circuits. For others to replicate the analysis, it would be necessary to request the cases from CMP as stated in the IGP.

c. Solution Development

Based on the analysis of the system, CMP identified violations as summarized in Exhibit 4.3: Transmission and Distribution Needs Summary of the IGP (pg. 68). CMP further grouped the violations by season (summer/winter), DER driven and how many unique violations there are. Segregation of DER driven needs and solutions was at the request of stakeholders as these costs are generally born solely by the DER customer.[10] As this is a scenario study, CMP focused on the common drivers related to future load growth and DER expansion – overloaded transformers and circuits - as needs that would typically require transmission and distribution upgrades.[11]

For the purpose of assessing potential solutions, CMP grouped the violations into one of 16 categories based on type - transmission/distribution, near term/long term, thermal/voltage, circuits/transformer, severity.[12] CMP then identified representative solutions for each category, acknowledging that findings are indicative of broader system needs under the forecasted growth and DER expansion scenarios.

CMP provided a narrative description for a list of potential solutions, noting advantages and disadvantages of the distinct types of solutions. CMP subdivided the potential solutions as follows: Customer-controlled solutions, Lower Severity Needs Solutions, and Higher-Severity Needs

[9] CMP IGP at page 56.
[10] See CMP IGP at page 65.
[11] Summary tables of the distribution and transmission violations are provided in Exhibits 4.4 and 4.6, respectively, of the CMP IGP.
[12] See Exhibit 5.2 Categorization of Needs in CMP IGP.

Solutions. CMP then selected a representative set of 70 circuits to develop potential solutions and extrapolate findings to provide a system-wide view.

The expected level of overload and availability of alternate feeders were key factors in solution development. The availability of potential alternate feeders was also a key factor in evaluation of potential solutions. CMP evaluated solutions based on the level of overload projected and the specifics of the overload, noting that most overloads occur in the winter. CMP approached solutions that considered how projects would address both thermal needs and voltage needs.

For each category, CMP identified four potential solutions and then evaluated them using the DOER/MPUC scorecard, comparing alternatives across cost, technical performance, EEEJ and policy alignment categories as provided in the scorecard. Subcategory metrics are detailed in tables on pgs. 92-93 of the IGP.

The solutions considered fell in one of the four categories,

- shift load/reconfigure network (increase utilization of existing equipment where possible)
- peak shaving/load management (where possible to manage flows through power injections from storage devices or power reductions of customer load).
- upgrade equipment to add capacity (where cost effective),
- build new infrastructure to add capacity (where other lower cost options not viable)

CMP provided 4 sample case studies to illustrate the evaluation process in greater detail, along with scorecards for all 16 categories demonstrating the evaluation across violation types and severities. This scorecard evaluation was required by the Order and can be a reasonable approach for assessing the likely future scope and magnitude of investment in transmission and distribution infrastructure that might be needed. It does not substitute for the utility T&D project level capital planning, which would typically encompass many other system needs and more comprehensive analysis that is case specific for each identified system violation. CMP cites the IGP as a basis for its capital planning in their soon to be filed Rate Case, but does not provide specifics.[13]

4 WHERE DID CMP FALL SHORT OF THE ANALYSIS AS PRESENTED IN DOCKET 2022-00322?

a. Scenarios and Models

Study case development is a critical first step in scenario planning, defining projected load and generation levels and their locations so that contingency analysis can identify system needs. The Order required specific scenarios as discussed earlier, for which CMP developed study cases to satisfy the requirements. CMP included six additional study cases for the purpose of analyzing

[13] See Feb 17, 2026 letter to MPUC, Re: Central Maine Power Company, Notice of Intent to File a One Year Rate Case and Seek Temporary Rates. CMP states *"The Company's capital investment plan and proposed electric operations workforce expansion are based upon the significant needs and range of potential solutions identified in CMP's Integrated Grid Plan (filed December 15, 2025, in Docket 2022-00322), and the likelihood of increasingly severe storms identified in the Company's Climate Change Protection Plan (filed December 29, 2023, in Docket No. 2023-00282)."*

transmission flows at the seams between ME and NH. The process followed by CMP in the development of the scenario study cases and performance of engineering analysis was consistent with good utility practice for grid scenario planning studies.

The CELT 2024 load forecast was required as the basis for the developing the scenarios and CMP developed its engineering models accordingly. CMP acknowledged the likely impact of legislative changes and a reduction in projected load growth from 2024 to 2025. Nonetheless, the trend toward electrification of load is expected to continue, albeit at a slower pace. For this study, the CELT 2024 forecast is a reasonable basis.

To the extent that a stakeholder would wish to replicate the studies, additional information would be needed from CMP. Since the Order does not require replicability, this does not constitute a deficiency. Independent analysis would require circuit-level modeling detail where local growth trends deviate from the system-wide trend. CMP provides information in the IGP for obtaining study cases noting that CEII[14] access and permission for confidential information will be required.[15]

Ambient Adjusted Ratings (AARS)

CMP notes the plans for incorporating Ambient Adjusted Ratings (AAR) for its transmission lines to comply with FERC Order 881 and that it is expected to be complete by 2027. AARs allow for higher capacity on lines when the ambient temperature is cooler than the base assumption of the normal and emergency ratings. The implementation of AARs can unlock system capability in operations and potentially reduce congestion. AARs, however, are not typically applied in reliability planning studies, which must plan for the most severe conditions that typically occur at peak load in summer periods. As the system shifts to winter peaks and CMP implements enhanced data collection and times series analysis, it may offer opportunities for more detailed location specific studies that consider ratings at lower temperatures than currently applied. Greater circuit data granularity could allow CMP to identify correlations between lower temperatures, higher circuit loading, and temporarily elevated conductor ratings — potentially avoiding or deferring upgrades.

b. Analysis

The process followed by CMP in the performance of analysis was consistent with good utility practice for grid scenario planning studies, though best practices are evolving to meet changing grid needs with high DER deployment and opportunity to leverage flexible loads. Utilities, such as Pacific Gas & Electric, modeled scenarios that represent more realistic operational decisions and integrating demand response and flexible operation incentives to identify potential for reduced needs and avoidance of infrastructure investment.[16] The Order specified the specific scenarios to be studied and therefore CMP's analysis would not be considered deficient. Integration additional

[14] Critical Energy/Electrical Infrastructure Information (CEII) is CEII is defined as information related to or proposed to critical electric infrastructure, generated by or provided to the Commission or other Federal agency other than classified national security information, that is designated as critical electric infrastructure information by the Commission or the Secretary of the Department of Energy pursuant to section 215A(d) of the Federal Power Act.
[15] See CMP IGP at pages 49 and 56.
[16] Pacific Gas and Electric Company, Draft Electrification Impact Study Part 2, R.21-06-017 (Cal. P.U.C. Oct. 31, 2025) (PG&E Draft EIS Part 2).

scenarios, such as a "mitigated" scenario that accounts for different customer behaviors and adoption of customer programs may provide more insight in future IGP submittals.

c. Solutions

Grid solutions generally fall into two categories: improving utilization of existing infrastructure through load shifting and load management, or adding capacity through upgrades or new construction.

Load Shifting

Shifting load is often considered as a first option, particularly with distribution system planning. As indicated by CMP's scorecard for Scorecard Template Category 1, low severity near term distribution circuit overloads, load shift was the preferred solution. However, shifting load is very location dependent as it relies on available nearby alternate circuits with available capacity. When available, it is generally the most economic option. CMP's solutions include transfers to alternate circuits; however, rephasing and phase rebalancing should also be listed explicitly as potential options.

Battery Energy Storage Systems (BESS)

Where Shifting load is not feasible or economic, battery energy storage systems (BESS) is identified as strong candidate for peak shaving and overload mitigation. CMP identified BESS as a preferred solution in 2 categories and as an alternate solution in 7 of the 16 categories. Storage is increasingly recognized not as a supplemental resource, but as a foundational tool for actively managing the variability and bidirectional complexity that high DER penetration introduces. Deployed effectively and at sufficient scale, it can defer or avoid costly T&D upgrades, smooth variable renewable integration, and preserve affordability for customers.[17] Expanding the deployment of storage should be a standard option in CMP's toolbox of solutions. Despite its identification in 9 of 16 categories, CMP treats BESS primarily as a pilot concept.[18] CMP identifies the cost of BESS as a key hurdle to implementation when compared to other conventional solutions. An economic evaluation of BESS and other alternative solutions could demonstrate more clearly where BESS may be the more cost-effective solution.

Rate recovery for BESS may also be a barrier, particularly at the transmission level where batteries are often considered energy resources and therefore not eligible for transmission cost of service rate recovery except as a transmission only asset. CMP acknowledges this regulatory uncertainty[19] but does not suggest a plan for addressing this barrier. Section 6 recommends that CMP specify the barriers it perceives and outline innovative approaches, such as third party ownership with clear contractual obligations to implementing BESS where it is the more economical solution.

Load Flexibility

CMP recognizes that load flexibility in various forms, such as battery storage, smart thermostats and smart EV chargers, can offer solutions to grid needs as the grid evolves with higher

[17] The Storage Gap: Deployment Challenges in the East (2026), available at www.gridlab.org.
[18] See CMP IGP at page 121.
[19] See CMP IGP at page 86.

electrification and DER deployment. While not a complete substitute for grid investment, the Maine Pathways to 2040 study found that load flexibility is an important strategy for mitigating near-term impacts and deferring upgrades.[20] To enable greater use of load flexibility, CMP noted that it requires 1) deployment of grid and customer technologies, 2) technology investments such as ADMS and DERMS, and 3) integration with customer programs and/or rate design.[21] CMP should work collaboratively with Efficiency Maine Trust (EMT) and DOER to undertake proactive customer engagement and actively recruit participants for smart home device and demand flexibility programs. Although planned technology investments will ultimately offer greater value, near-term benefits may be achievable under the current paradigm; the IGP does not clearly articulate how CMP is pursuing those opportunities today.

Dynamic Line Ratings

CMP identified implementation of Dynamic Line Ratings (DLR) as a potential alternate and preferred solution in Scorecard Categories 12 and 16. DLR is emerging in the industry as a relatively low-cost upgrade to increase the utilization of existing transmission lines by incorporating actual weather conditions (wind speed being most impactful) into the real time ratings. Static ratings are designed conservatively to ensure actual conditions rarely result in lower capacity than assumed in planning studies. The expectation is that system operators can direct the operation of the system based on static line ratings, regardless of the variability of the conditions that affect the actual capacity of the line. DLR application has largely been reserved for addressing real-time operational congestion rather than planning-stage overload resolution. CMP provided little detail on what additional steps would be needed to incorporate DLR as a regular planning solution beyond pilot project experience.[22]

Other design elements, such as the use of high temperature conductors, converting single circuits to double circuit lines, use of compact design structures, or similar design aspects would be best addressed in the project level development to account for the project-specific information.

5 WHERE DID CMP FALL SHORT IN TERMS OF BEST PRACTICES?

CMP's practices are generally representative of industry standards. Standardized reliability metrics — CAIDI, SAIDI, and SAIFI — are used to prioritize distribution system needs.[23] CMP notes its ongoing replacement of bare conductors with covered wire (tree wire) and spacer cables, which are well-established solutions to improve reliability performance in heavily treed areas. Additional practices include sectionalizers and reclosers to isolate outages and restore unaffected sections, minimizing customer impact.[24]

Where CMP utility practices are most wanting is with respect to its accuracy of data records, data access, and the software tools to share the data more effectively and efficiently plan and operate

[20] The Brattle Group, Maine Pathways to 2040, prepared for Maine Governor's Energy Office, January 2025. Available at https://www.maine.gov/energy/sites/maine.gov.energy/files/2025-01
[21] See CMP IGP at page 113.
[22] See CMP IGP at pages 86 and 122.
[23] See CMP IGP at page 34.
[24] See CMP IGP at page 32.

the system. Effective distribution planning in an era of rapid DER growth and electrification is only as strong as the data and mapping infrastructure that underlies it. Robust GIS capabilities are foundational to understanding where load is growing, where DERs are interconnecting, and where constraints are emerging.[25] Poor or fragmented data management practices, by contrast, lead to reactive and inefficient capital deployment, missed opportunities to leverage DERs as grid assets, and an inability to accurately assess the true costs and benefits of competing investment options

System Maps and Records - CMP identified it has inaccurate or incomplete maps of parts of its distribution system[26], which are critical to efficiently and effectively plan the system. CMP is addressing this through an ongoing mapping remediation effort and governance improvements. It is notable that CMP has 69 distribution lines that are over 100 miles long, one that is 250 miles long, which is highly unusual.[27]

- CMP should prioritize accurate facility mapping and records, with governance to ensure ongoing maintenance.

Data Integration, Quality, and Integrity – CMP currently does not have the data or the tools necessary to access the system data to enable time series analysis that would provide a more granular view of the loading on the circuits and feeder spurs. CMP has identified several initiatives related to data enhancement as priorities in its 10-year roadmap.

- CMP should prioritize integrating AMI and SCADA data into CYME and related platforms to enable time-series analysis.

Flexible Management Tools – CMP is expected to have significant growth in DER deployment which will present operation challenges without greater ability to flexibly manage its distribution system. CMP has identified ADMS and DERMS as key priorities to be able to implement flexible operations. While these tools provide the necessary technical capability, regulatory barriers must also be addressed as discussed in the IGP.

- CMP should prioritize ADMS and DERMS implementation to manage expanding DER deployment and load growth.
- CMP should develop a roadmap to address regulatory barriers to DERMS and other emerging technology deployments.

Solution Evaluation and Project planning - CMP described its evaluation methodology on a generic basis, with only selected illustrative examples. For capital planning, these grid needs should be described with much more detail including size (MW), duration (h), cause, and cost to customers if not addressed. When assessing historical data, planners might consider factors such as rate of growth, duration of peak loads, timing of day of peaks, abnormal switching configurations, atypical loading patterns. In addition to the historical data and trends for circuits and substations, planners will often consider extent of economic development in an area and potential for future development, likelihood of continued trends, potential solutions, and time to implement solutions.

[25] GridLab, Geographic Information System (GIS) Best Practices: A Guide on GIS for Electrification, available at www.gridlab.org.
[26] See CMP IGP at page 120.
[27] See CMP IGP at page 31.

The decision to proceed with a project will often have multiple decision points that consider the project justification based on the most current information, the time complete the upgrade to resolve the violation and the estimated cost.

- Incorporating the MPUC scorecard framework into CMP's project level planning process would embed evaluation factors not currently reflected in its capital planning methodology.

6 RECOMMENDATIONS

CMP's IGP addresses all technical requirements of the Order, and the issues discussed in this report do not rise to the level of formal deficiency. Significant room for improvement remains, particularly in the priority areas identified in the Order.[28]

The following recommendations address how CMP can more fully achieve the priorities required by the Order and meet the evolving needs of the grid.

1. **Advanced load forecasting and time series analysis**

   CMP should implement its Advanced Load Forecasting initiative without delay and accelerate its efforts where feasible, as this work underpins a broader range of grid solutions. Customer-level time-series analysis encompasses several interdependent initiatives: distribution system mapping improvements, process automation, and enhanced data collection and analytics. While CMP provided a high-level roadmap in Exhibit 6.1 CMP should develop a more detailed implementation plan for each initiative, including specific milestone dates and measurable progress metrics. As a best practice for major operational changes, the plan should also include a discussion of key risks and corresponding risk mitigation strategies.

   CMP has acknowledged that feeder maps are inaccurate or outdated, circuit loading visibility is limited, and data integration is manual and resource-intensive. Resolving these deficiencies is essential to more frequent hosting capacity map updates, identified as Priority #2 in the Order. Given the level of DER penetration on the system, advanced load forecasting with time series analysis is expected to better identify opportunities for DER

[28] MPUC identified the following priorities – 1. Reliability and resilience improvements: Make investments that cost-effectively maintain or improve reliability; Reduce barriers to promote cost-effective nonwires alternatives (NWA) solutions and identify any process improvements/efficiencies; and Build climate adaptation into the investment solution mix. 2. Improve data quality and integrity to maximize its use in distribution system planning: Leverage investments in Advanced Metering Infrastructure (AMI); Improve mapping of the distribution system and develop a governance policy or protocols for maintaining the integrity of the data on an ongoing basis; Develop initial roadmap for advancing time-series planning1 models; and Enhance hosting capacity maps to benefit stakeholder decision making by standardizing them across utilities. 3. Promote flexible management of consumers' resources and energy consumption: Improve forecasting electric vehicle (EV) load, distributed energy resources (DER) adoption, and climate parameters; Support integration and utilization of DERs to enable load flexibility and resilience. Technologies or programs to shift load from system peak to reduce Maine's share of the Regional Network Service (RNS) charge.

integration, support a wider array of cost-effective solutions to grid constraints, such as BESS and flexible load management, and facilitate faster interconnection of DERs.

2. **Develop a roadmap to integrate data enhancing technology initiatives into annual planning processes**

   CMP should provide greater detail on the functional planning enhancements expected in the near, mid, and long term from the initiatives described above. While CMP has offered a high-level roadmap for its data improvement initiatives, it is unclear how or when these tools will be incorporated into CMP's annual project planning processes, such that CMP can more fully consider the range of solutions that it has identified in its IGP. The roadmap should include clear milestones for partial and full implementation, with explicit links to routine planning workflows. Additionally, case studies would be valuable in illustrating the types of data these tools will make accessible and the enhanced analyses they will enable within annual planning processes.

3. **Develop a plan to address Regulatory Barriers to Flexible operations**

   CMP should provide greater specificity on the steps it will take to address regulatory barriers impeding full utilization of DER value through DERMS and NWA deployment. CMP has identified several such barriers, including questions around technology ownership, the roles and responsibilities of utilities, third parties, and EMT, cost recovery and allocation, and the alignment of incentive structures with customer and system benefits. However, the IGP does not clearly explain how CMP intends to address these barriers or which issues require action by other entities.

   CMP should identify specific barriers to BESS and NWA implementation and distinguish between actions within its control and those dependent on external parties. For issues beyond CMP's direct control, the plan should identify the relevant parties responsible for resolution, describe what alternative approaches could be pursued, and outline any advocacy or coordination steps CMP intends to take.

4. **Milestone and Progress Metrics for the IGP**

   CMP should establish specific, measurable targets for each initiative in Section 8. Some existing metrics — such as percentage of circuits with Distribution Automation — are quantifiable but lack defined targets; others amount to status updates rather than benchmarks. CMP should establish clear milestones enabling objective progress assessment and timely identification of delays. Future IGPs should document actions taken from the prior filing and any steps needed to keep initiatives on track.

7 POTENTIAL IMPROVEMENTS FOR FUTURE IGPS

The Commission's order identifies specific scenarios for system planning purposes, with only one scenario explicitly designated as a winter. As the region's electric system continues its transition

from summer-peaking to a winter, the current snapshots may not be representative of future grid conditions. CMP's initial IGP identified the majority of violations occurring in winter, underscoring that winter conditions now present the greatest reliability challenges.[29]

Winter peak conditions introduce complexities that differ fundamentally from summer peak operations. Evening demand peaks driven by heating loads, morning ramp events as residences and businesses begin their day. Extended cold weather episodes with sustained heating demand over multiple days may present distinct reliability and resource adequacy challenges. Prolonged cold weather events with fuel supply constraints that can materially affect the resource mix needed to maintain system reliability.

The Commission should consider either (1) broadening the prescribed scenario snapshot set to include other winter events, such as an extended cold weather event, or (2) providing utilities with greater latitude to develop and propose scenarios that best reflect their specific system characteristics and emerging risk profiles. A more flexible approach would allow planners to analyze dual-peak dynamics, test the resilience of resource portfolios under fuel-constrained conditions, and identify potential gaps that a single winter scenario may not reveal.

8 GLATZ ENERGY CONSULTING LLC

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Ms. Glatz is an energy industry consultant with over 40 years of engineering and planning experience in the RTO and utility sectors. Before founding Glatz Energy Consulting, she served as the Director of Strategic Initiatives and Interregional Planning at PJM Interconnection, where her key focus areas included public policy planning, transmission planning, and Order 1000 competitive planning. Prior to her role at PJM, Ms. Glatz spent 11 years at PPL Electric Utilities, holding various management and engineering positions in transmission planning, distribution planning, and regulatory functions related to the transmission business. She also worked as a consulting engineer for 15 years, specializing in system analysis, engineering, and design for transmission and distribution projects across several engineering firms. Ms. Glatz is a registered Professional Engineer in Pennsylvania. She holds a Bachelor of Science in Electric Power Engineering from Rensselaer Polytechnic Institute, a Master of Science in Electrical Engineering from the New Jersey Institute of Technology, and an Executive MBA from Temple University's Fox School of Business.

[29] See CMP IGP at page 69.