

STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2023-00103

November 3, 2023

MAINE PUBLIC UTILITIES COMMISSION
Amendments to Small Generator
Interconnection Procedures
(Chapter 324)

ORDER ADOPTING RULE
AND STATEMENT OF
FACTUAL AND POLICY
BASIS

BARTLETT, Chair; SCULLY and GILBERT, Commissioners

I. SUMMARY

Through this Order, the Commission adopts amendments to its Small Generator Interconnection Procedures Rule (Chapter 324). This rulemaking makes changes to facilitate the interconnection process for all levels of generation facilities and implements the requirements of legislation.

II. BACKGROUND

A. Chapter 324

Chapter 324 establishes procedures and protocols for interconnections to transmission and distribution (T&D) systems for small generators that are not subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC). The rule establishes requirements for four discrete generating facility categories: Level 1, Level 2, Level 3, and Level 4, including protocols for application and review procedures. Chapter 324 was last amended on December 21, 2021. *Maine Public Utilities Commission, Amendments to Small Generator Interconnection Procedures Rules (Chapter 324)*, Docket No. 2021-00167, Order Amending Rule and Factual and Policy Basis (December 21, 2021).

B. L.D. 1100

In 2022, the Legislature enacted L.D. 1100. P.L. 2021 Ch. 264. L.D. 1100 requires that the Commission contract with an expert to evaluate Maine's procedures and practices to:

- Ensure that the timelines and requirements for interconnection do not unduly limit the ability of residential and nonresidential customers to install on-site solar energy generation and battery storage systems to offset a customer's electrical consumption and that interconnection costs for these customers are limited to interconnection facility upgrades and do not include the cost of distribution upgrades. P.L. 2021 Ch. 264 § 2.

- Improve the transparency of interconnection screens and upgrades for customer-sited generation. P.L. 2021 Ch. 264 § 2.
- Ensure that dispute resolution processes for residential and nonresidential interconnection customers are fair and efficient and do not place a disproportionate burden of technical expertise and cost on these customers. P.L. 2021 Ch 264 § 3.

Further, Section 2(3) of L.D. 1100 provides that the Commission should determine and adopt allocation methods for interconnection studies and upgrades that ensure that on-site solar energy generators do not bear prohibitive costs for their projects to be studied and interconnected to the distribution system.

Pursuant to L.D. 1100, in February 2022, the Commission engaged the Interstate Renewable Energy Council (IREC) to evaluate Maine's procedures and practices to ensure solar and storage projects that serve a customer's own electricity needs are interconnected efficiently and without bearing costs for distribution grid upgrades. The results of IREC's evaluation and its recommendations are contained in its report "Interconnection Standards, Practices, and Procedures to Support Access to Solar Energy and Battery Storage for Maine Homes and Businesses" (2022 IREC Report). *Commission Initiated Inquiry into IREC Report*, Docket No. 2022-00071, Notice of Inquiry, Attachment A (March 14, 2022).

Finally, L.D. 1100 also provided that the Commission should ensure that its interconnection rules reflect nationally recognized best practices; that customers are able to access a timely resolution process that does not place an undue burden on customers; and that investments in T&D upgrades related to load are coordinated with utility infrastructure required for the interconnection of renewable capacity resources using solar power. 35-A M.R.S. 3474.

C. Inquiry (Docket No. 2022-00345)

On December 5, 2022, the Commission initiated an Inquiry into Chapter 324. *Maine Public Utilities Commission, Inquiry into Proposed Changes to Small Generator Interconnection Procedures (Chapter 324)*, Docket No. 2022-00345, Notice of Inquiry (Dec. 5, 2022) (Inquiry). The purpose of the Inquiry was to gather input from interested persons on potential changes to Chapter 324 based on the IREC Report. The Notice of Inquiry (NOI) included a draft of Chapter 324 with proposed edits. Comments were filed by the Office of the Public Advocate (OPA), Central Maine Power Company (CMP), Versant Power (Versant), Efficiency Maine Trust (EMT), Natural Resources Council of Maine (NRCM), A Climate to Thrive (ACTT), Spencer Egan, ReVision Energy (ReVision), the Governor's Energy Office (GEO), the Maine Renewable Energy Association (MREA), and the Coalition for Community Solar Access (CCSA).

On March 17, 2023, the Hearing Examiners issued a procedural order in the Inquiry docket, requesting that the CMP and Versant respond to specific questions regarding their practices in the interconnection process. Versant and CMP filed

responses.

III. RULEMAKING PROCESS

On May 23, 2023, the Commission issued a Notice of Rulemaking (NOR) and proposed amendments to Chapter 324. Consistent with rulemaking procedures, the Commission provided interested persons with the opportunity to provide oral comments on the proposed rule during a public hearing held on June 22, 2023. The Commission also provided three opportunities to file written comments: once on June 13, 2023, once on June 20, 2023, and final comments on July 7, 2023. In their role as the expert hired to evaluate Chapter 324, IREC filed a review and analysis of the comments in this rulemaking on September 15, 2023 (2023 IREC Report).

The following interested persons provided comments on the proposed amendments to the rule: GEO, Competitive Energy Services, LLC, Newtility LLC, CMP, EMT, Versant, CCSA, MREA, ReVision, Maine Solar Solutions, OPA, ACTT, SolarLogix, LLC (SolarLogix), and Sundog Solar.

IV. AMENDED RULE PROVISIONS

A. Cost Allocation for Projects Serving On-Site Load

1. L.D. 1100

Section 2(3) of L.D. 1100 required that after contracting with an expert to evaluate 324, the Commission determine and adopt cost allocation methods for residential and non-residential customers that ensure that on-site solar energy generators do not bear prohibitive costs for their projects to be studied and interconnected.

2. Proposed Rule

In the proposed rule, the Commission suggested that waiving the Distribution Upgrade costs for Level 1 customers would achieve the goals of L.D. 1100. The Commission also proposed a Distribution Upgrade cost waiver ceiling of \$5,000 for Level 1 projects. The Commission requested comments on whether projects above 25 kW should be eligible for a Distribution Upgrade cost waiver if those larger projects install on-site solar energy generation and battery storage systems to offset their electrical consumption. Finally, the Commission requested comments on the cost waiver ceiling and how the costs of the waived Distribution Upgrades should be recovered.

3. Comments on Proposed Rule

In its comments on the proposed rule, Versant stated that many of the circuits on its distribution system are at capacity, and that distributed generation (DG) facilities

attempting to interconnect on these circuits will likely incur significant upgrade costs. Versant June 13 Comments at 2-3. Versant suggested that it was unfair to make all ratepayers bear the costs of Distribution Upgrades for specific projects, and that the Commission should remove Distribution Upgrade cost waivers from consideration. Versant June 23 Comments at 3-5. The OPA expressed its opposition to a Distribution Upgrade cost waiver because of the potential impact on lower income customers. OPA June 13 Comments at 1-2, 4-5, 4.

In its comments, CMP suggested that projects over 25 kW should not have their costs waived because the costs for upgrades for such projects are much higher than the upgrade costs for smaller projects. CMP June 13 Comments at 1. Both the GEO and ReVision stated that L.D. 1100 contemplated projects larger than 25 kW that served on-site load, and that the waiver should not be limited only to Level 1 projects. GEO June 13 Comments at 2-3; ReVision June 15 Comments at 2-4. The GEO expressed support for a cap on the total Distribution Upgrade cost that may be waived and agreed with the NOR that a \$5,000 cap for Level 1 facilities is appropriate. GEO July 7 Comments at 2.

In its comments, CES stated that project size should be based on export capacity and not nameplate capacity. CES July 7 Comments at 7. IREC suggested that the focus should not be on the size of the project but instead on whether the project serves on-site load. 2023 IREC Report at 6. IREC recommended a definition for a project that would qualify for the protections identified in L.D. 1100 and suggested that if the Commission was concerned about large Level 4 projects taking advantage of a waiver, the Commission could select a cap on the size of eligible projects based on existing information about solar projects in Maine that serve on-site load. *Id.* IREC noted that the average size of systems in Maine intended to serve commercial on-site load is 285 kW while the national average is 101.6 kW. *Id.*

The OPA suggested that when considering whether to exempt projects from paying for Distribution Upgrades, the Commission should be mindful of the impact of such an approach on ratepayers. OPA June 13 Comments at 4. The OPA also stressed the importance of applying cost causation principles to interconnection costs. *Id.* at 5. To ensure a fair allocation of costs, the OPA recommended that Distribution Upgrade costs be recovered through either a flat fee per project or a per-kW fee. *Id.* at 9. EMT expressed support for a per-kW fee that is scaled to account for the higher costs of larger projects. EMT July 7 Comments at 4. CES stated that it did not oppose the concept of flat interconnection fees but recommended that such a fee is not applied to all types of distributed generation and energy storage systems that are governed by Chapter 324. CES July 7 Comments at 7.

ReVision proposed that all projects serving on-site load be responsible for the first \$1,000 in upgrade costs, and that additional costs up to \$5,000 be waived. ReVision July 6 Comments at 8. In their final comments, Maine Solar Solutions, Sundog Solar, and SolarLogix expressed support for ReVision's proposal. Maine Solar Solutions July 7 Comments at 1; Sundog Solar July 7 Comments at 3; SolarLogix July 7 Comments at 2. IREC suggested that ReVision's proposal could be a reasonable

compromise but suggested that \$5,000 limit on waived upgrade costs may be too low of a cap. 2023 IREC Report at 8. IREC emphasized that the Commission would benefit from better data when establishing the values for a fee or a waiver, and that the Commission could re-evaluate the fee after a year of collecting data. *Id.* at 9.

Finally, the OPA stated that L.D. 1100 does not require that projects serving on-site load have their Distribution Upgrade costs waived. OPA July 7 Comments at 2-3. Instead, the OPA stated that Section (2) of L.D. 1100 required that the Commission contract with an expert to evaluate near-term reforms to Maine's standards, practices, and procedures related to the interconnection of solar generation facilities. *Id.* at 2. The OPA argued that the Commission satisfied this mandate when it retained IREC to write the 2022 IREC Report. *Id.* The OPA stated that the only mandate set forth in L.D. 1100 regarding costs is for the Commission to adopt cost allocation methods that ensure that on-site generators do not bear prohibitive costs. *Id.* at 2-3. The OPA noted that in the 2022 IREC Report, IREC found that most states use a "cost-causer pays" approach for the allocation of small project upgrade costs. *Id.* at 3, citing 2022 IREC Report at 12. The OPA noted that in keeping with the cost-causer approach, multiple states have adopted per-kW interconnection fees, which results in costs being shared across all eligible interconnection customers, as opposed to such costs being socialized to all customers through a rate case. *Id.* at 3-4.

4. Decision on Cost Allocation

The Commission agrees with the OPA that L.D. 1100 does not require that Distribution Upgrade costs be waived for projects that serve on-site load. Instead, the mandate set forth in L.D. 1100 regarding interconnection costs is for the Commission to "adopt cost allocation methods for interconnection studies and upgrades that ensure that on-site solar energy generators *do not bear prohibitive costs*" (emphasis added).

L.D. 1100 does not specify what size a project must be to qualify as an on-site-load generator that should not bear prohibitive costs. As proposed in the NOR, the Commission believes that one intent of L.D. 1100 was to ensure that smaller residential customers installing roof-top solar not bear prohibitive costs. Consistent with the NOR, it is reasonable to assume that Level 1 projects serve on-site load and should not bear prohibitive costs to interconnect. However, as IREC notes, limiting the definition of on-site-load generation to Level 1 projects could leave larger projects serving on-site load with prohibitive upgrade costs, which may not satisfy the Legislature's goals under L.D. 1100. 2023 IREC Report at 6. Therefore, the amended rule includes definitions for "On-Site Load" and "On-Site-Load ICGF" to capture projects larger than Level 1 that serve on-site load. Specifically, the amended rule provides that an "On-Site Load-ICGF" is a Level 2 project above 25 kW and up to 250 kW that only serves to offset on-site load. An "On-Site-Load ICGF" includes projects that export generation through the Net Energy Billing (NEB) kWh Credit program but does not include projects that export generation under the NEB Tariff Rate. The Commission believes that the 250 kW size cap should adequately capture the projects contemplated by L.D. 1100. This is supported by information gathered during the Inquiry, in which CMP stated that most

projects above 250 kW have two or more off-takers. Docket No. 2022-00345, CMP January 20, 2023 Comments.

While in the NOR the Commission proposed a waiver of Distribution Costs for On-Site-Load ICGFs (which was limited to Level 1 projects), as the Commission has already noted, L.D. 1100 does not require that Chapter 324 waive Distribution Upgrade costs. L.D. 1100 requires that projects serving on-site load do not bear prohibitive costs. Ensuring that these Interconnection Customers do not bear prohibitive costs requires the Commission to balance the needs of Interconnection Customers and ratepayers. Multiple commenters have suggested that the requirement that on-site-generators not bear prohibitive interconnection costs can be achieved through an approach by which interconnection costs are recovered through either a flat fee per project or a per-kW fee. The Commission agrees and believes that a flat fee recovered from specific groups of customers that qualify as On-Site-Load ICGFs strikes the right balance to ensure that no individual qualifying project bears prohibitive costs, while also protecting ratepayers.

In the Inquiry, CMP noted that Level 1 interconnectors do not usually require Distribution Upgrades to interconnect. Docket No. 2022-00345, CMP April 14, 2023 Comments at 2. In the rare instances where they do require Distribution Upgrades, the upgrade needed is typically a single-phase service transformer upgrade to the next largest size. *Id.* CMP does not charge Level 1 customers for new transformers. *Id.* Data from the recent CMP rate case shows that the costs for single-phase service transformers for Level 1 projects are currently socialized in rate base,¹ as the transformer upgrades needed for Level 1 projects usually serve multiple customers. Docket No. 2022-00152, Data Request OPA-018-011. In CMP territory, Level 1 projects that require single-phase service transformer upgrades are only charged for the labor and travel to install the transformer. Docket No. 2022-00345, CMP April 14, 2023 Comments at 2.

The Commission amends the rule to provide that both utilities should not charge Level 1 customers for new single-phase service transformers. The costs of these transformers should be socialized and recovered from all ratepayers, as the transformers can benefit more than one customer. This practice is also consistent with how the utilities are currently treating transformer upgrades due to load growth associated with beneficial electrification.

While the amended rule implements CMP's current practice of socializing the cost of single-phase service transformers for Level 1 customers and recovering those costs from all ratepayers, CMP does currently charge Level 1 customers for the travel and labor needed to install a transformer. CMP stated in its response to the Inquiry that

¹ The costs for single phase transformers for Level 2 projects in CMP territory are also recovered through rate base, due to the transformer benefitting not only the Interconnection Customer, but other customers as well. Docket No. 2022-00152, Data Request OPA-018-011.

the average cost for travel and labor for a Level 1 customer that needs a single-phase service transformer is approximately \$925 per project. Docket No. 2022-00345, CMP April 14, 2023 Comments at 2. In order to cover the costs of travel, labor, and any other non-single-phase service transformer Distribution Upgrade equipment (costs which are not recovered from ratepayers) for Level 1 customers, the amended rule provides that all Level 1 projects shall pay a flat fee of \$150. The amended rule gives the Commission the opportunity to adjust the flat fee to ensure that the fee reflects actual costs experienced by Level 1 Interconnection Customers.

The rule requires T&D Utilities to use the \$150 fee collected from all Level 1 customers to pay for travel and labor for any Level 1 customers that require upgrades, along with any non-single-phase service transformer Distribution Upgrade equipment required for a Level 1 customer to interconnect. When setting this fee, the Commission relied on data provided from CMP and Versant in the Inquiry about number of Interconnection Customers and average upgrade costs for Level 1 projects. The \$150 fee is intended to ensure that instead of paying directly for unforeseen Distribution Upgrades, Level 1 customers only need to pay the flat fee.² However, if an individual Level 1 project has combined labor, travel, and non-transformer Distribution Upgrade costs that exceed \$5,000, the Customer shall pay all costs beyond \$5,000. The flat fee approach is supported by multiple commenters and should ensure that no individual Level 1 project bears prohibitive costs, thereby satisfying the legislative mandate under L.D. 1100. Additionally, the flat fee approach effectively balances the needs of the Interconnection Customers and ratepayers by ensuring that ratepayers do not subsidize the costs for Distribution Upgrades that solely benefit an individual Level 1 Interconnection Customer, while also ensuring that single-phase service transformers for Level 1 projects are treated the same as similar transformers needed to accommodate load growth due to beneficial electrification.

To ensure that On-Site-Load ICGFs do not face prohibitive costs, the Commission adopts a cost allocation method similar to the Level 1 fee. Like Level 1 projects, On-Site Load ICGFs will not pay for new single-phase service transformers. However, unlike Level 1 customers, the amended rule provides that On-Site Load ICGFs will pay a \$25 per-kW fee. The collective per-kW fees the utilities collect from the On-Site Load ICGFs will be used to cover all non-single-phase service transformer Distribution Upgrade costs, including travel and labor. However, if the combined costs for the non-single-phase service transformer Distribution Upgrades, labor and travel for an individual On-Site ICGF exceeds \$10,000, the participating customer shall pay any amount above \$10,000. When setting the \$25 per kW fee and \$10,000 cap for these projects, the Commission relied on data submitted by the utilities in the Inquiry. The amended rule requires T&D Utilities to use the pooled per kW fees to pay for Distribution Upgrades for qualifying ICGFs up to the \$10,000 cap.

² Level 1 Interconnection Customers must still pay all non-Distribution Upgrade fees, including application fees.

While the amended rule sets the same flat fee and per-kW fee for both T&D Utilities, the rule allows both Versant and CMP to establish separate values for the fee and caps for these projects based on specific costs in their service territories. These specific costs will be determined in a separate proceeding.

Finally, the definition of “Distribution Upgrades” has been amended to make clear that Distribution Upgrades are those additions, modifications, and upgrades to the interconnecting T&D system at or beyond the utility-owned infrastructure side of the Point of Common Coupling to accommodate interconnection of the ICGF. The Commission emphasizes that it is important to recognize this distinction, especially with the implementation of the flat fee and per-kW fee for Distribution Upgrades. Additionally, because the fees may be modified based on actual cost data, it is important that the utilities maintain accurate records of the costs of Distribution Upgrades versus Interconnection Facilities.

B. Aggregated Generation

1. Current Definition

Many of the technical review screens contained in Section 7 of Chapter 324 assess whether a project has the potential to impact grid safety and reliability of the Distribution System. If a project passes these screens, it can be processed as a Level 1 or Level 2 project and interconnected without extensive delay. Often the impact on grid safety and reliability is best understood when considering a proposed project within the larger context of the Aggregated Generation on the Distribution System.

As currently written, Chapter 324’s definition of Aggregated Generation includes all existing in-service generation, the generation from the proposing ICGF, and “all ICGFs that have paid the T&D Utility for 100% of interconnection-related costs attributable to it, including costs for studies, distribution facilities, system upgrades, metering, and other items which the ICGF has cost responsibility.” Current Ch. 324 § 2(A). The plain language of the current rule refers to “100% of interconnection-related costs.” This would appear to refer to both transmission and distribution costs. This reading made it nearly impossible for a Level 4 project to be considered Aggregated Generation and safe from restudy, since it could only pay for all costs following completion of ISO-NE study. However, in 2022, the Commission clarified that the interconnection-related costs an ICGF must pay to be counted as Aggregated Generation were limited to distribution-related costs. *Central Maine Power Company, Request for Approval of Waiver of Chapter 324*, Docket No. 2020-00211, Order Clarifying Order Granting Waiver (Oct. 20, 2022).

2. Proposed Rule

In the NOR, the Commission proposed that the definition of Aggregated Generation be amended to include all existing generation, the generation from the proposed ICGF, and projects with a fully executed interconnection agreement (IA),

regardless of whether they have paid for their Distribution Upgrades.

3. Comments

Both CMP and Versant generally expressed support for the definition proposed in the NOR. Versant June 13 Comments at 3; CMP June 13 Comments at 2. ReVision, Sundog Solar, ACTT, GEO, and MREA/CCSA opposed the proposed definition.

GEO expressed concern that including Level 4 projects with an executed IA in the definition of Aggregated Generation will negatively impact small projects and risk saddling them with delays and uneconomic upgrade costs. GEO June 13 Comments at 3. The GEO also suggested that if the Commission adopts the proposed definition, the Commission should reserve a certain amount of capacity for small projects. *Id.* at 4.

MREA/CCSA expressed support for the current definition of Chapter 324, where Aggregated Generation only includes those Level 4 projects that have paid for their Distribution Upgrades. MREA/CCSA also proposed that once the invoice for Distribution Upgrades has been issued to the Level 4 project, any Level 2 project that applied within 30 days of the invoice being issued would be placed on hold until the Level 4 project paid the invoice, or 30 days have passed. MREA/CCSA June 13 Comments at 3-4. MREA/CCSA stated that this proposal would rebalance the treatment of Level 2 and Level 4 projects. Alternatively, MREA/CCSA proposed adding a cutoff date to the proposed definition of Aggregated Generation, reverting to the existing definition after December 31, 2024, the commercial operate date deadline for the NEB program. *Id.* at 4.

ReVision expressed concern that many Level 4 projects with executed IAs may never actually be built and could use their IAs to reserve queue capacity for speculative projects. ReVision June 15 Comments at 5. Because of this, ReVision argued that the current definition of Aggregated Generation should remain in place. ReVision also provided a proposal for reserving capacity for smaller projects that ReVision called the "Fast Track Interconnection Program," or "FTIP." ReVision July 6 Comments. ReVision noted that its proposal for capacity reservation would be best reviewed in a separate proceeding. *Id.* at 6. Until then, however, ReVision recommended that the Commission not amend the current definition of Aggregated Generation. *Id.* at 2.

Like ReVision, ACTT, Sundog Solar, and SolarLogix recommended not changing the current definition. SolarLogix June 13 Comments at 1; ACTT July 7 Comments at 2; Sundog Solar June 13 Comments at 1-2. ACTT and Sundog Solar also supported ReVision's proposal for reserving capacity.

While CMP expressed support for the proposed definition, CMP noted in its Comments that a Level 4 project is still susceptible to leapfrogging until the IA is executed. For example, should a project be undergoing its System Impact Study (SIS) at the time it is leapfrogged, CMP will have to restart the SIS to account for generation of new Level 1 and Level 2 projects. Docket No. 2022-00345, CMP June 13, 2023

Comments at 2.

4. Decision on Aggregated Generation

With respect to Aggregated Generation, the Commission adopts the definition proposed in the NOR. Specifically, Section 2(A) is amended to provide that Aggregated Generation includes all existing generation, the generation from the proposing generator, and all projects with a fully executed IA.

While the Commission appreciates the concern from some commenters that the proposed definition could impact smaller projects, and also appreciates the proposal by MREA/CCSA whereby Level 2 projects would be placed on hold until a Level 4 project pays its Distribution Upgrades, the problem with tying Aggregated Generation status with payment for Distribution Upgrades is that it ignores the realities of the queue system. Even if a Level 4 project does everything “right” - has an executed IA and pays for 100% of its Distribution Upgrades in – this does not necessarily insulate the project from constant restudy. If there is another Level 4 project ahead of it in the queue that has not paid for its Distribution Upgrades, the project that has paid may still be subject to restudy. This results in a situation where a project can never truly rely on its executed IA and may be forced into an endless cycle of restudy depending on the actions of others in the queue and the Level 2 interconnection applications. While it is important that Level 1 and Level 2 projects are processed with minimal delay, the Commission must also ensure that the interconnection process is efficient and predictable for all projects.

IREC has noted that including all projects with an executed IA as Aggregated Generation aligns more with practices nationwide. 2023 IREC Report at 12. However, IREC notes that the most common practice is to consider all queued-ahead projects as Aggregated Generation, even those that have not yet signed an IA. 2023 IREC Report at 12; 2022 IREC Report at 19-24. The Commission does not support including all queued-ahead projects as Aggregated Generation because doing so could lead to speculative projects taking up space, leading to smaller projects unnecessarily failing screens. The Commission believes that only including those projects that have a fully executed IA strikes the right balance between ensuring that Level 4 projects are not subject to constant restudy, while also requiring that such projects have shown a commitment to interconnecting.

The Commission believes that IA execution is a reasonable test of project maturity and commitment. Projects that have executed their IA have paid their application fee and incurred SIS costs and potential modification and re-study costs under Chapter 324. They are aware of the cost of the Distribution Upgrades to interconnect and commit to those costs when executing an IA. Further, the IA itself is a contract, and the contracting parties should be able to reasonably rely on the contract. However, the Commission emphasizes that the amended definition will only work if the T&D Utilities strictly follow the queue management requirements already outlined in the rule by enforcing timelines.

It is important to note that this definition does not guarantee that a Level 4 project will not require restudy. A project will be susceptible to leapfrogging while it is in its SIS phase. In this case, and even after completing the SIS but prior to execution of the IA, the Level 4 project could be responsible for additional upgrades if a new SIS is needed due to a Level 2 project applying prior to execution of the IA. The Commission believes this is a reasonable risk for the Level 4 project and believes that the IA execution date is the appropriate date at which a project should no longer be at risk of being leapfrogged by a Level 2 project. Additionally, while this definition minimizes the risk of leapfrogging, it does not insulate a Level 4 project from the need for a restudy if projects ahead of it in the queue withdraw.

While the Commission appreciates the capacity reservation proposal, such proposals cannot be examined in the context of this rulemaking due to a lack of time and insufficient information.

Finally, the amended definition of Aggregated Generation complies with Section 3(A) of L.D. 1100, which provides that Maine's interconnection rules should reflect nationally recognized best practices. 35-A M.R.S. § 2474.

C. Level 2 Size

The proposed rule reduced the Level 2 size threshold from 2 MW to 1 MW. In the NOR, the Commission noted that under Chapter 324, the Level 2 interconnection process is intended to allow a more streamlined approach to interconnection in comparison to the Level 4 process. Because projects that are larger than 1 MW require ISO-NE approval, the Commission reasoned that including projects larger than 1 MW defeated the purpose of the streamlined Level 2 approach. In the NOR, the Commission declined to adopt IREC's recommended table-based approach to define project level size.

CMP and Versant both supported the proposed reduction, and suggested the Commission further reduce the size to 500 kW. Versant June 13 Comments at 3; CMP June 13 Comments at 2. GEO and ReVision both supported the adoption of IREC's proposed table-based approach. GEO June 13 Comments at 4, ReVision June 20 Comments at 8.

ReVision expressed concern that the Commission's proposed change could result in projects sized 1 MW to 2 MW being required to undertake unnecessary studies simply because of their size. ReVision June 13 Comments at 8. SolarLogix also opposed changing the current size threshold for Level 2 projects. SolarLogix June 13 Comments at 1-2. IREC continued to recommend adopting the table-based approach, and also recommended not lowering the threshold below 1 MW. 2023 IREC Report at 15.

Because the amended rule adopts changes to the definition of aggregated generation and adopts additional screens, the amended rule does not change the size threshold for Level 2 projects. The Commission acknowledges that IREC's proposal of a table-based approach could, in limited circumstances, allow for more nuance based on circuit voltage, proximity to substation and conductor size. However, the Commission finds that Maine does not need this level of specificity for its T&D system. The Commission finds that based on Maine's system, the table-based approach could in some instances be more restrictive and result in more projects failing. Additionally, while projects sized between 1 MW and 2 MW will require ISO-NE study, developers of these projects are most likely aware of this requirement, and the projects may still be expedited through the distribution system interconnection process and potentially join a cluster sooner if they pass all the screens.

D. Minor System Modifications

The proposed rule amended the definition of Minor System Modifications to make clear that Minor System Modifications are *Distribution Upgrades*. The Commission also proposed amending the rule so that it explicitly stated that if a project requires more than \$30,000 in Distribution Upgrades, it will need to reapply as a level 4.

CMP and the GEO both supported the proposed revision in their comments. CMP June 13 Comments at 3, GEO June 13 Comments at 4. ReVision raised a concern about automatically sending Level 1 projects through the Level 4 process because of expensive distribution upgrades. ReVision June 13 Comments at 9. ReVision proposed an alternative wording that would allow Level 1 projects to reserve a place in line until sufficient upgrades had occurred to allow Level 1 projects to interconnect with less expense. ReVision June 15 Comments at 9. IREC finds the Commission's proposal to be reasonable but also agrees with ReVision that it is inefficient to automatically send all Level 1 projects requiring more than \$30,000 in minor system modifications through the Level 4 process. 2023 IREC Report at 16. IREC suggests that the Commission leave that decision to the T&D Utility. 2023 IREC Report at 16-17.

The amended rule adopts the proposed change that clarifies that Minor System Modifications refers specifically to Distribution Upgrades. The amended rule does not adopt the proposal that requires T&D Utilities to automatically send projects requiring more than \$30,000 in minor system modifications to go through the Level 4 process. The Commission agrees with IREC that T&D Utilities should have the discretion to determine whether a project can stay in the Level 1 or Level 2 pool even if the project requires more than \$30,000 in minor system modifications.

E. Automatic Sectionalizing Device

The proposed rule updated the definition of Automatic Sectionalizing Device to clarify that it means interrupting devices that can automatically re-energize a line, like line reclosers. The proposed rule stated that a fuse is not an Automatic Sectionalizing

Device. The Commission proposed this amendment to help align Maine's T&D Utility practices with nationwide best practices. IREC stated that by defining "line section" as bounded by a fuse, "the usefulness of the screen for catching actual safety and reliability concerns is lost and it instead will catch too many projects that could be interconnected safely and reliably without further study." 2022 IREC Report at 33.

The Commission proposed the changes to the definitions of Automatic Sectionalizing Device and Aggregated Generation to balance Maine's policy interest in moving forward smaller projects with minimal delay with the continuing need to ensure that the interconnection process is efficient and predictable for projects of all sizes.

Versant was the only stakeholder to oppose the new definition of Automatic Sectionalizing Device. Versant June 13 Comments at 3. Versant acknowledged that this issue is a historic issue since nearly all developers are now using UL 1741 SB-certified inverters. Versant June 20 Comments at 18. CMP shared Versant's concerns for line safety. CMP June 20 Comments at 3. IREC believed that Versant's concerns are misplaced and does not see anything unique to Versant's system that justifies defining a fuse as an Automatic Sectionalizing Device. 2023 IREC Report at 18.

The amended rule adopts the proposed change to the definition of Automatic Sectionalizing Device. The Commission finds that nationwide best practices do not require T&D Utilities to include "fuse" in the definition of Automatic Sectionalizing Device.

F. Energy Storage

L.D. 528, signed in 2021, directed an assessment of Maine's energy storage market and established energy storage goals of 300 MWs of installed capacity within the state by the end of 2025 and 400 MWs by the end of 2030. Interconnection plays a vital role in the process of adding energy storage to Maine's market. Energy storage can be connected to the grid as a stand-alone ICGF, or as a component of an ICGF with generation. Energy storage can charge directly from the grid, from associated generation, or both. Each configuration of energy storage poses its own special considerations for interconnection.

Chapter 324 currently does not differentiate between energy storage and other types of ICGF. Chapter 324 also does not require Interconnection Customers to provide information that, especially with respect to energy storage, may facilitate the interconnection process for energy storage for customers and T&D Utilities. The proposed rule included a new Section 10 that describes the minimum amount of information an Interconnection Customer shall provide to a T&D Utility when the Interconnection Customer's ICGF includes energy storage. In addition, the proposed rule added a new definition for energy storage, defining it as an "Energy Storage System" (ESS) and using the definition in M.R.S. 35-A Section 3481.

1. Information on Application Forms

CMP and Versant suggested that the Commission develop a form that requests the information about ESS in the proposed rule. CMP June 13 Comments at 4-5; Versant June 20 Comments at 11. IREC agreed with CMP's proposal and suggested the Commission model the proposed forms on sample forms in IREC's 2023 Model Interconnection Procedures.

The amended rule adopts the suggestions of CMP and Versant and directs the Commission to develop an ESS Application Information Form as one of the standard forms described in Section 4.

2. ESS Operating Profiles

Both EMT and the GEO suggested the rule explicitly take into account operating profiles for ESS. EMT June 13 Comments at 1; GEO June 13 Comments a 5. IREC cited its Building a Technically Reliable Interconnection Evolution for Storage (BTRIES Toolkit) when acknowledging the absence of best practices for operating profiles in its recommendation that the Commission abstain from adopting operating profiles in the current rule. 2023 IREC Report at 20.

The Commission relied on current nationwide best practices when it refrained from requiring operating profiles for ESS in the proposed rule. As IREC observed in the BTRIES Toolkit, there are no established standards for operating profiles with respect to interconnecting ESS. The amended rule does not require T&D Utilities to consider ESS operating profiles when interconnecting ESS. The Commission notes that nothing in the rule prohibits developers and T&D Utilities from agreeing to specific operating profiles on a case-by-case basis when developing an IA for ICGFS that include ESS.

3. ESS Definition

CES suggested revising the proposed definition of ESS for clarity. CES June 13 Comments at 2-3. Versant opposed CES's suggestions. Versant June 20 Comments at 12-13. IREC did not recommend changing the proposed definition. 2023 IREC Report at 20.

The Commission refrains from changing the definition of ESS in the amended rule. The Commission finds that there is currently utility in maintaining consistency of definitions across statutes and Commission rules. The amended rule adopts the proposed definition of ESS.

4. ESS Charging Assumptions

CES proposed adopting an assumption that utilities shall assume that ESS never charges during peak load conditions. CES June 13 Comments at 2-3. EMT, the OPA, and the GEO supported CES's proposal. EMT June 13 Comments at 2; OPA July 7

Comments at 5; GEO July 7 Comments at 3. Versant opposed CES's proposal and cited to factors apart from peak load conditions that lead to ESS decisions to charge. Versant June 20 Comments at 5-6. CMP also opposed CES's suggestion and pointed to assumptions CMP must make when interconnecting ESS. CMP June 20 Comments at 3. IREC agreed "with CES that the utility should take into account whether the ESS would generally be charging from solar when reviewing the proposed project, but only if the customer provides the utility with evidence that the system design prevents it from charging from the grid." 2023 IREC Report at 21. IREC did not find CES's blanket assumption regarding ESS charging reasonable. *Id.*

The amended rule does not add any requirements regarding assumptions with respect to when an ESS may charge from the Distribution System. The Commission finds it unreasonable to adopt blanket assumptions for the charging of all ESS interconnecting to the distribution system. The Commission finds that it is unreasonable to assume that an ESS never charges during peak times, just as it is unreasonable to assume that an ESS only charges during peak times. While the amended rule is currently silent on charging assumptions, the amended rule does include information about export controls that should be included with an ESS application. The Commission suggests that a T&D Utility should take export controls into account when analyzing an ICGF that includes ESS.

G. Export Capacity and Screen 7(J)

The addition of ESS to an existing ICGF will result in a subsequent change in the Nameplate Rating of the ICGF. Including ESS with an ICGF may increase the ICGF's flexibility with respect to charging from the grid and discharging onto the grid. To accommodate the challenges posed by accounting for ESS Nameplate Rating, flexibility, and complexity, the Commission proposed a new Section 8 that introduced the concept of export controls. While export controls are especially relevant to ICGFs that include ESS, the Commission recognizes that export controls are an important consideration for the interconnection of all ICGFs.

The proposed Section 8 incorporates the language suggested in the BTRIES Toolkit that IREC released on March 22, 2022. Reliable and trusted means of controlling the exporting of energy onto the grid are an essential component of interconnecting energy storage and other limited or non-exporting ICGFs. The proposed Section 8 incorporates the language suggested in the BTRIES Toolkit for export controls.

In order to incorporate the BTRIES Toolkit suggestions for export controls, the proposed rule added new definitions, including "Export Capacity", "Inadvertent Export", "Limited-Export ICGF", "Nameplate Rating", "Non-Exporting ICGF", and "Power Control System". The proposed rule also incorporated export control requirements into the existing screens for all levels. The proposed rule also added Export Capacity to screens 7(A) and 7(E). Finally, the proposed rule amended Screen 7(E) to include a reference to the Nameplate Rating of the transformer instead of providing a specific value in kilovolt amps. The proposed rule did not incorporate a screen for Inadvertent Export.

1. Screens 7(A) and 7(E)

Commenters who commented on the proposed changes to Screens 7(A) and 7(E) commented favorably. The amended rule adopts the proposed changes to Screens 7(A) and 7(E).

2. Inadvertent Export and new Screen 7(J)

CMP and Versant were the only commenters who expressed reservation about Inadvertent Export. CMP opposed permitting any Inadvertent Export. CMP June 13 Comments at 5. Versant similarly suggested that an ICGF should be designed to prevent Inadvertent Export. Versant June 20 Comments at 10.

In its analysis of comments, IREC commented that avoiding all Inadvertent Export is unreasonable. 2023 IREC Report at 22. IREC provided a summary of research that found that “at least for most small projects, the effects [of inadvertent export] would be negligible, and even for larger projects it can be effectively screened for.” *Id.* at 23. To address the concerns expressed by the T&D Utilities, IREC recommended the Commission adopt a new screen 7(J) for Inadvertent Export as introduced in the BTRIES Report. *Id.*

The Commission recognizes the concerns of the T&D Utilities regarding Inadvertent Export. The Commission finds IREC’s suggested screen a reasonable way to address those concerns. The amended version of the rule creates a new Screen 7(J) that directs T&D Utilities to screen an ICGF that can introduce Inadvertent Export when the ICGF’s Nameplate Rating minus its Export Capacity exceeds 250kW. Screen 7(J) introduces a threshold and formula to determine if a proposed ICGF requires further power flow analysis. The screen, threshold, and formula in the proposed rule comply with the expert-recommended national practices described in the BTRIES Toolkit.

H. Informal Dispute Resolution

L.D. 1100 requires that the Commission make the informal dispute resolution process easier for Interconnection Customers. The Commission has observed that a T&D Utility and an Interconnection Customer may disagree on whether the parties have engaged in good faith negotiations. The proposed rule modified the requirements of original Section 15A to require less formality to commence the Informal Dispute Resolution process.

The Commission also observed that Interconnection Customers associated with smaller projects may engage in the dispute resolution process without notifying the developer who installed the ICGF about the interconnection issues. Because Interconnection Customers, developers, and T&D Utilities all benefit from participation in the dispute resolution process, the proposed rule modified original Section 15(B) to require developer participation in informal dispute resolution.

The proposed rule also clarified that if a T&D Utility enters into default acceptance for a Level 1 facility because the T&D Utility fails to approve or deny an application 20 Business Days after the receipt of an application, an Interconnection Customer is not required to go through the good faith negotiations process before bringing the issue to the attention of Commission Staff through the Informal Dispute Resolution process.

1. Requesting Good Faith Negotiations

CMP and Versant commented that T&D Utilities need a way to distinguish requests for good faith negotiation from other types of customer communication. CMP June 13 Comments at 6; Versant June 13 Comments at 4-5. Versant proposed a form could be used to initiate good faith negotiations. Versant June 13 Comments at 5.

IREC agreed with the T&D Utilities that Interconnection Customers should have a formal way to initiate good faith negotiations. IREC agreed that a form or informational pamphlet could help Interconnection Customers become aware of and initiate the informal dispute process. 2023 IREC Report at 25.

Since this rulemaking process has begun, the Commission has created a website and a webform that interconnection customers may use to initiate good faith negotiations with T&D Utilities. Interconnection Customers are directed to the website if they contact the Commission's Consumer Assistance and Safety Division (CASD) and may use the webform to initiate good faith negotiations. This approach seems to be helping Interconnection Customers initiate good faith negotiations. The amended rule refrains from making the proposed change about initiating good faith negotiations until the Commission has time to evaluate the effectiveness of the webform.

2. Developer Involvement in Good Faith Negotiations

ReVision recommended that developers be allowed to represent Interconnection Customers in the informal dispute resolution process. ReVision June 13 Comments at 11. ReVision commented in opposition of the proposal that developers be required to participate in good faith negotiations. *Id.* Both ReVision and SolarLogix supported further revisions to the dispute resolution process in a future proceeding. Revision July 6 Comments at 4-6; SolarLogix June 13 Comments at 3.

Versant commented that, in some circumstances, it is beneficial to include developers in dispute resolution. Versant June 13 Comments at 5. Versant suggested that developer participation would be especially helpful when Interconnection Customers are surprised about upgrade costs, or when Interconnection Customers are expected to understand technical, electrical engineering-related interconnected issues. Versant June 20 Comments at 24; Versant July 7 Comments at 9.

IREC agreed with ReVision that developer participation in the dispute resolution process should be permitted but not required. 2023 IREC Report at 25. IREC commented that it was best to leave it to the Interconnection Customer and the developer to decide if the developer should be involved in the dispute resolution process. *Id.*

The Commission agrees that some aspects of dispute resolution are better addressed with developer involvement. The Commission further finds that dispute resolution is an option for Interconnection Customers even if Interconnection Customers lack developer representation or support. However, the Commission also agrees that not all informal dispute resolutions benefit from developer involvement. The proposed rule requires developers to be notified that good faith negotiations have been initiated and leaves Commission Staff discretion to determine if developers should be invited to participate in the proceedings described in Sections 17(B) and 17(C) of the amended rule.

3. Ombudsperson

The GEO cited recent legislation to recommend the Commission include in this rulemaking an Ombudsperson and a fee to pay for the Ombudsperson position in compliance with L.D. 327. GEO July 7 Comments at 1-2. IREC recognized that L.D. 327 requires the Commission to create the Ombudsperson position. The amended rule does not add include the ombudsperson position. The Commission plans to address the ombudsperson requirements of L.D. 327 in a later proceeding when all interested persons have an opportunity to comment on the proposal.

I. Transparency

In response to the Procedural Order issued in the Inquiry on March 17, 2023, T&D Utilities identified steps, including site visits, that T&D Utilities take with respect to the interconnection of Level 1 and Level 2 ICGFs. Docket No. 2022-00345, Versant April 14, 2023 Comments at 3. These steps were not described in Chapter 324. The proposed rule describes in more detail the steps the T&D Utilities already take as a part of the interconnection process. In addition, the proposed rule adds information T&D Utilities must provide to Interconnection Customers about reasons for failing screens and details about cost estimates.

1. Screen Information

CMP and Versant did not oppose providing Level 1 and Level 2 Interconnection Customers with additional information about the reasons that screens are failed. Versant expressed concerns about the costs of providing this information. Versant June 13 Comments at 4. CMP expressed concerns about the time required to provide the additional information. CMP June 13 Comments at 6. ReVision suggested that the additional information in screen results should include information about the minimum

daytime load relied upon when analyzing screen results. ReVision June 13 Comments at 12.

IREC commented that providing this additional information should not require significant additional resources because T&D Utilities should simply share information the T&D Utilities already have when they conduct the screens. 2023 IREC Report at 26. IREC also commented in support of ReVision's suggestion for information about daytime minimum load. *Id.*

The Commission agrees that providing Level 1 and Level 2 Interconnection Customers with information a T&D Utility relies upon when making its initial screening determinations should not take additional time or work. The Commission does not see a reason a T&D Utility should have to repeat work the T&D Utility has already done if an Interconnection Customer asks for specific data related to screen failure. The amended rule adopts the changes related to transparency made in the proposed rule. In addition, the amended rule requires T&D Utilities to make available information about minimum load and minimum daytime load the T&D Utility used to conduct screens for Level 1 and Level 2 projects. The amended rule does not grant T&D Utilities additional money or time to provide Level 1 and Level 2 Interconnection Customers with the information required in the amended rule.

2. Additional Transparency Requirements

ReVision expressed concerns about additional technical screening conducted by Utilities that was not specifically contemplated under Chapter 324. ReVision June 16 Comments at 12-14. ReVision urged the Commission to require a T&D Utility to engage in a formal, public proceeding when it finds the screens in Chapter 324 insufficient to ensure safety and reliability of the Distribution System. *Id.* at 14. ReVision suggested some of these concerns would be addressed with a new approach toward cost allocation for Distribution Upgrades for smaller projects. *Id.* at 13. The GEO commented that a quarterly reporting requirement on some interconnection metrics would help increase transparency. GEO June 13 Comments at 6-7. CMP commented in opposition to the GEO's proposal. CMP June 20 Comments at 3-4.

IREC agreed that the screens described in Chapter 324 should be sufficient for interconnection and T&D Utilities should be prohibited from using additional technical screens not included in the rule. 2023 IREC Report at 26-27. IREC also agreed with the GEO that a reporting requirement would help ensure "compliance with interconnection procedures and help shape future policy." 2023 IREC Report at 26. IREC commented that quarterly may be more frequent than necessary. 2023 IREC Report at 26.

The amended rule does not adopt specific language about T&D Utility conduct with respect to additional technical screens or about a reporting requirement. The Commission finds that the increased transparency requirements should address concerns raised by Interconnection Customers and the new screens should be sufficient to address technical concerns of T&D Utilities. The Commission finds that the dispute

resolution process remains an avenue for Interconnection Customers to pursue if Interconnection Customers feel they have been denied interconnection in violation of Chapter 324.

J. Level 3 Interconnection

Chapter 324 defines Level 3 projects as non-exporting ICGFs that are not larger than 10 MW. The Commission's proposal to add export controls to the rule gives the Commission the opportunity to further clarify which screens apply to the interconnection of non-exporting ICGFs. The proposed rule incorporates the suggested language from IREC's Model Interconnection Procedures dated September 2019. The proposed rule also added a requirement for a T&D Utility to seek a waiver from the Commission if the T&D Utility prevents a non-exporting ICGF from interconnecting due to a reduction in load.

The GEO and ReVision commented in support of the proposed change. GEO June 13 Comments at 7; ReVision June 13 Comments at 14. Versant expressed concern that upgrades to individual circuits may be necessary to mitigate higher voltage that may result when a Level 3 project reduces the load on the circuitry. Versant June 13 Comments at 4. CMP observed that a Level 3 project could impact circuit availability for other projects in the queue and noted that a Level 3 project may need upgrades to interconnect. CMP June 13 Comments at 6. In its analysis, IREC supported the addition but acknowledged that cost causation may need to be reconsidered as more ICGFs, specifically customer-sited generation, interconnect to the distribution system of T&D Utilities. 2023 IREC Report at 27.

The amended rule adopts the changes in the proposed rule.

K. New Screen 7(I)

In responses to the Procedural Order dated March 17, 2023, the T&D Utilities observed that when they evaluate interconnection issues for ICGFs, they regularly employ an additional test related to the quality of service and voltage. The proposed rule formalizes this requirement and adds a new Screen 7(I). The new Screen 7(I) recognizes a requirement for T&D Utilities that already exists in Chapter 320 of the Commission's rules.

The GEO, Versant, and CMP commented in support of the new screen. GEO June 13 Comments at 7; Versant June 20 Comments at 23; CMP June 13 Comments at 7. CMP requested additional time to complete the proposed screen. CMP June 13 Comments at 7. ReVision opposed the proposed screen in its comments. ReVision June 13 Comments at 15. ReVision states that Screen 7(A) is sufficient to account for the issues identified in the proposed screen. *Id.* ReVision suggested that the rules should allow a T&D Utility and an Interconnection Customer to engage in dispute resolution if a T&D Utility identifies voltage regulation issues. *Id.* at 15-16. Sundog Solar suggested that if the Commission adopts Screen 7(I), the T&D Utility should be

required to provide the Interconnection Customer with the mathematical data that supports the T&D's finding that a proposed ICGF failed the screen.

IREC commented that Screen 7(A) should be sufficient to account for any voltage issues. 2023 IREC Report at 28. IREC also acknowledged that if the proposed Screen 7(l) formalizes an existing requirement for the T&D Utilities, then "it is not unreasonable for the Commission to add this screen. *Id.* at 28. IREC further commented that the added transparency requirements should be sufficient to address the concerns raised by ReVision and Sundog Solar in their opposition to the proposed Screen 7(l). *Id.* Finally, IREC recommended that the Commission not extend the deadlines in the rule to accommodate the proposed Screen 7(l). *Id.*

The amended rule adopts the proposed Screen 7(l). The Commission finds that this screen formalizes a requirement in another Commission Rule. The amended rule also extends the deadline for performing all of the screens for Level 1, Level 2, and Level 3 Customers. This extension is to accommodate site visits. The Commission finds that Level 1, Level 2, and Level 3 Interconnection Customers do not receive information about all of their costs until after the T&D Utility completes the site visit. The Commission clarifies that, with this extension, all T&D Utilities are required to provide complete cost estimates by the time of execution of an IA, and that those estimates are to include information about costs gathered during the site visit. The Commission finds that giving this extra time reflects the practice as it currently occurs, while making T&D Utilities responsible for conducting site visits in a timely manner and providing complete cost information at the time of execution of an IA and not changing that information after an IA has been signed.

L. Retroactive Waiver

On June 8, 2023, the Commission issued a Notice of Investigation in Docket No. 2023-00127 to determine whether good cause exists to retroactively waive Distribution Upgrade costs for eligible Interconnection Customers. *Public Utilities Commission, Investigation of Chapter 324 Retroactive Distribution Upgrade Waiver*, Docket No. 2023-00127, Notice of Investigation and Request for Comments (June 8, 2023). The Commission will conclude that docket after this rule is issued.

V. ORDERING PARAGRAPHS

Accordingly, the Commission

ORDERS

1. That the amendments to Chapter 324, Small Generator Interconnection Procedures, as described in the body of this Order and as set forth in the attached amended rule are hereby adopted.

2. That the Administrative Director shall file the amended rule with the Secretary of State.
3. That the Administrative Director shall notify the following of the adoption of the amended rule:
 - a. All transmission and distribution utilities in the state;
 - b. All persons that filed comments or are on the notification list for this proceeding;
 - c. All persons who have filed with the Commission within the past year a request for notice of rulemakings; and
 - d. The Office of the Public Advocate.
4. That the Administrative Director shall provide a copy of the amended rule to the Executive Director of the Legislative Council, 115 State House Station, Augusta, Maine 04433-0115.

Dated at Hallowell, Maine, this 3rd day of November, 2023.

BY ORDER OF THE COMMISSION

/s/ Harry Lanphear
Harry Lanphear
Administrative Director

COMMISSIONERS VOTING FOR: Bartlett
 Scully
 Gilbert

NOTICE OF RIGHTS TO REVIEW OR APPEAL

5 M.R.S. § 9061 requires the Public Utilities Commission to give each party at the conclusion of an adjudicatory proceeding written notice of the party's rights to seek review of or to appeal the Commission's decision. The methods of review or appeal of Commission decisions at the conclusion of an adjudicatory proceeding are as follows:

1. Reconsideration of the Commission's Order may be requested under Section 11(D) of the Commission's Rules of Practice and Procedure (65-407 C.M.R. ch. 110) within **20** days of the date of the Order by filing a petition with the Commission stating the grounds upon which reconsideration is sought. Any petition not granted within **20** days from the date of filing is denied.
2. Appeal of a final decision of the Commission may be taken to the Law Court by filing, within **21** days of the date of the Order, a Notice of Appeal with the Administrative Director of the Commission, pursuant to 35-A M.R.S. § 1320(1)-(4) and the Maine Rules of Appellate Procedure.
3. Additional court review of constitutional issues or issues involving the justness or reasonableness of rates may be had by the filing of an appeal with the Law Court, pursuant to 35-A M.R.S. § 1320(5).

Pursuant to 5 M.R.S. § 8058 and 35-A M.R.S. § 1320(6), review of Commission Rules is subject to the jurisdiction of the Superior Court.

Note: The attachment of this Notice to a document does not indicate the Commission's view that the particular document may be subject to review or appeal. Similarly, the failure of the Commission to attach a copy of this Notice to a document does not indicate the Commission's view that the document is not subject to review or appeal.