BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UM 2111

In the Matter of PUBLIC UTILITY COMMISSION OF OREGON, Investigation Into Interconnection Process and Policies.	**JOINT UTILITIES' INITIAL COMMENTS REGARDING EXPORT CONTROL AND SUPPLEMENTAL REVIEW ISSUES**

I. INTRODUCTION

In accordance with Staff's "Summary of September 14 Meeting," filed in docket UM 2111 on September 20, 2022, Portland General Electric Company (PGE), PacifiCorp dba Pacific Power (PacifiCorp), and Idaho Power Company (Idaho Power) (together, the Joint Utilities) provide the following comments.

These comments address two proposals from the Interstate Renewable Energy Council (IREC) that would: (1) create export control requirements for Distributed Energy Resources (DERs)[1] to limit the export of electrical power across the Point of Interconnection (POI); and (2) create a Supplemental Review process that could be applied to certain DERs that would otherwise require more comprehensive interconnection studies as a result of failing to pass applicable screening criteria. On August 5, 2022, IREC circulated the proposals for review. On August 26, 2022, the Joint Utilities provided redlines in advance of the September 14, 2022, workshop, at

[1] As currently proposed by IREC, DER "means the equipment used by an interconnection customer to generate and/or store electricity that operates in parallel with the electric distribution system. A DER may include but is not limited to an electric generator and/or Energy Storage System, a prime mover, or combination of technologies with the capability of injecting power and energy into the electric distribution system, which also includes the interconnection equipment required to safely interconnect the facility with the distribution system." *See* IREC Export Control Section Discussion Starter, Definitions.

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which stakeholders discussed the proposed changes. The Renewable Energy Coalition (REC) also provided comments via email on September 7, 2022, and proposed redlines on October 4, 2022, which relate to the calculation of daytime minimum loads used in the Supplemental Review process.

The Joint Utilities generally support IREC's recommendations, subject to critical but relatively modest revisions discussed below. Providing greater clarity regarding applicable export controls will remove uncertainty while ensuring that interconnecting DERs do not compromise the safety and reliability of the utility's system. Creating a Supplemental Review process in Oregon would also provide greater flexibility to the utility and interconnection customer that could streamline the interconnection process for well-sited DERs.

IREC's proposals would require amendments to both the Public Utility Commission of Oregon's (Commission) small generator interconnection rules found in OAR Chapter 860, Division 82, and the net metering interconnection rules found in OAR Chapter 860, Division 39. At this time, it is unclear how IREC's proposals would be incorporated into the existing rules, how the existing rules would need to be amended to account for IREC's proposals, and how the rulemaking process would work in conjunction with docket UM 2111. Therefore, while the Joint Utilities generally support IREC's recommendations, the Joint Utilities request greater clarity from Staff or the Commission regarding the process for implementing any changes to the Commission's rules based on decisions made in this docket. If the intent is to incorporate IREC's proposed language directly into the Commission's rules, the Joint Utilities may propose additional edits to conform the wording to the existing rules and ensure clarity.

II. GENERAL PRINCIPLES

The Joint Utilities support efforts to update and modernize Oregon's interconnection

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policies. In these efforts, two fundamental principles underlie the Joint Utilities' advocacy. First, updating interconnection policies should not result in the degradation of service to existing customers. Customers pay for a safe, reliable, and efficient distribution system. Fast-tracking DER interconnections at the expense of a robust study process could potentially undermine the safety, reliability, and efficiency of the existing system and leave customers worse off as a result. The Commission has recognized it is reasonable to require interconnection facilities that "ensure that system efficiencies remain in place and customer savings already in effect can continue."[2] Efforts to update interconnection policies should not undermine long-standing Commission policies protecting customers and ensuring a safe, reliable, and efficient system.

Second, updating the Commission's policies should not result in overly rigid or prescriptive requirements that create undue risk. The Joint Utilities are responsible for constructing, maintaining, and operating their transmission and distribution systems in compliance with all applicable safety and reliability requirements and in a prudent and reasonable manner. To that end, the Joint Utilities have unique familiarity and expertise that places their experts in the best position to recognize when a potential interconnection could cause a problem based on the specific facts and circumstances of the request. The Commission has recognized that a "utility's best practices and company standards . . . merit significant consideration when there is a request to set them aside."[3] This same "significant consideration" should be given to any proposed change to the interconnection rules that "sets aside" current best practices or creates an overly prescriptive process that would eliminate a utility's ability to conduct further study before approving an

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[2] *Sunthurst Energy, LLC v. PacifiCorp, dba Pacific Power*, Docket UM 2118, Order No. 21-296 at 5 (Sept. 15, 2021).
[3] Order No. 21-296 at 7; *id.* at 13 ("a default standard for the utility industry and an individual utility should not be set aside easily.").

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interconnection. Therefore, the Joint Utilities recommend caution when considering changes that would mandate automatic approval without further study because situations will undoubtedly arise where utility expertise reasonably necessitates additional study to determine whether an interconnection could have adverse system impacts or compromise the utility's system.

III. EXPORT CONTROLS

IREC's Export Controls document details IREC's proposed methods of controlling export from a DER. If a DER complies with one of these export control methods, then its interconnection capacity, as reflected in interconnection studies and the interconnection agreement, will be assumed to be only the amount capable of being exported—not the full nameplate capacity rating of the DER.

On August 5, 2022, IREC circulated the Export Controls document for review and comment by interested parties. On August 26, 2022, the Joint Utilities provided redlines in advance of the September 14, 2022, workshop, at which stakeholders discussed the proposed changes. The Joint Utilities generally support including the concept of acceptable export controls in the Commission's rules, subject to the revisions discussed below.

IREC recommends provisions to address acceptable export control methods for both non-exporting and limited-exporting DERs. For non-exporting DERs, IREC proposes three acceptable export control methods, designed to prevent a DER from compromising system safety and reliability by inadvertently exporting generation onto the utility's system: (1) reverse power protection (Device 32R); (2) minimum power protection (Device 32F); and (3) relative distributed energy resource rating.

Reverse power protection involves using a utility-grade protective relay to limit the export of power across the POI and requires that the default setting for this protective function be 0.1

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percent (export) of the service transformer's nominal base nameplate rating,[4] with a maximum 2.0 second time delay to limit inadvertent export.

Minimum power protection involves using a utility-grade protective relay to limit the export of power across the POI and requires that the default setting for this protective function be 5 percent (import) of the DER's total nameplate rating, with a maximum 2.0 second time delay to limit inadvertent export.

Relative distributed energy resource rating allows the applicant to forgo installing protective equipment but only if the DER's nameplate rating is no greater than 50 percent of the interconnection customer's verifiable minimum host load "during relevant hours over the past 12 months."[5]

A. Section 4.1.1 Reverse Power Protection (Device 32R) and 4.1.2 Minimum Power Protection (Device 32F)

The Joint Utilities generally support the proposed reverse power protection and minimum power protection provisions. However, the Joint Utilities recommend an important revision to both provisions to ensure system reliability when a non-exporting DER is interconnected to a circuit using high-speed reclosing. Under IREC's proposal, both the reverse power protection and minimum power protection methods require that the default setting for each protective function have a maximum 2.0 second time delay to limit inadvertent export.[6] This means that the DER would have up to 2.0 seconds to prevent the export of electricity onto the utility's system when

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[4] Nameplate Rating as used herein means "the sum total of maximum rated power output of all of a DER's constituent generating units and/or ESS as identified on the manufacturer nameplate, regardless of whether it is limited by any approved means." *See* IREC Export Control Section Discussion Starter, Definitions.
[5] IREC Export Control Section Discussion Starter, Section 4.1.3.
[6] Inadvertent Export as used herein means "the unscheduled export of active power from a DER, exceeding a specified magnitude and for a limited duration, generally due to fluctuations in load-following behavior." *See* IREC Export Control Section Discussion Starter, Definitions.

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adverse system conditions trigger the protective relay. However, a 2.0 second delay is too long on circuits with high-speed reclosing. If a circuit with high-speed reclosing experiences an event that requires the circuit to be disconnected from the grid, that disconnection will occur faster than 2.0 seconds. But if the DER's generation is not limited for up to 2.0 seconds, there could be a scenario where the DER is exporting generation onto a circuit that has been disconnected from the grid. This scenario results in "islanding," and it can be dangerous to utility workers who may not know that the disconnected circuit remains energized because of the DER's inadvertent exporting. Such instances of islanding can also prevent automatic reconnection of devices, damage utility and customer equipment, and compromise the safety and reliability of service.

To reduce this risk of islanding, IREC's proposal must be modified to ensure that the DER's safety equipment is appropriately calibrated to high-speed reclosing. Specifically, the Joint Utilities recommend the following language be incorporated into the description of the reverse power protection and minimum power protection export control methods: "When a project is located on a circuit using high-speed reclosing, the utility may require a maximum delay of less than 2.0 seconds to safely facilitate the reclosing." Without this change, adoption of IREC's proposal would unreasonably jeopardize safety and reliability, thereby making customers worse off as a result of the DER interconnection, which is contrary to the framework underlying the Commission's interconnection rules.

At the September 14, 2022, workshop, IREC expressed three concerns regarding the Joint Utilities' proposed additional language. First, IREC explained its primary concern is that the Joint Utilities' proposed language leaves it unclear to an applicant what requirements will apply. However, the Joint Utilities' proposed language is as specific as it reasonably can be, given that each utility has various reclosing speeds on different circuits. As revised by the Joint Utilities, the

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provisions explain that the default is a maximum 2.0 second time delay, but also make clear that when a project is located on a circuit using high-speed reclosing, the delay may need to be less to maintain safe and reliable system operation. The proposed revisions are reasonable as: (1) the interconnection customer can choose not to interconnect to a circuit with high-speed reclosing, and (2) it is reasonable to require customer adherence to existing utility practices, upon which other customers depend to maintain their existing quality of service. As the Joint Utilities explained during the workshop, the alternative to including this type of flexibility in the rules is to draft rules that address the highest possible reclosing speed—which would impose stricter-than-necessary requirements on many DERs that are located on non-high-speed reclosing feeders.

Second, IREC stated that safety and reliability concerns are addressed elsewhere in the rules and therefore the Joint Utilities' proposed language is unnecessary. As an initial matter, it is unclear whether IREC referred to the Commission's existing rules, which do not explicitly address protection and control requirements, or to other rules that IREC intends to propose in the future. Regardless, the Joint Utilities see no issue with having safety-related requirements addressed in multiple places, so long as the language is not inconsistent. Including the safety requirements in the Export Control provisions will increase clarity for applicants who may be reviewing only specific provisions, rather than the entire rules.

Third, IREC questioned if it is technologically feasible to achieve a less than 2.0 second delay. As the Joint Utilities explained at the workshop, it is technologically feasible and, in fact, some existing interconnection customers currently achieve a less than 2.0 second delay. If a DER is unable to achieve this speed, it can choose not to interconnect to a circuit with high-speed reclosing. The Joint Utilities' proposed revisions are consistent with their existing practices and are necessary to ensure safety and reliability and to maintain customers' existing quality of service.

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B. Section 4.1.3 Relative Distributed Energy Resource Rating

IREC also recommends a provision that would allow a non-exporting DER whose nameplate rating is no greater than 50 percent of the host facility's verifiable minimum load to not install any equipment to protect against inadvertently exporting to the distribution system. The Joint Utilities object to this provision because it relies exclusively on the presence of a host load to prevent reverse power flows. If the host load trips offline, then there would be no other protective equipment that would prevent the DER's generation from flowing onto the distribution system. By relying exclusively on host load and precluding the installation of protective equipment, IREC's proposal creates unnecessary and potentially significant risk. The Joint Utilities recommend that Section 4.1.3 be removed from the Export Controls document.

IV. SUPPLEMENTAL REVIEW

Under the Commission's existing interconnection rules, interconnecting DERs are required to undergo a comprehensive interconnection study process if the DER fails certain screening criteria set forth in the rules.[7] The proposed Supplemental Review process is designed to allow a utility to approve an interconnection request without conducting an interconnection study, even if the interconnecting DER fails one of the currently applicable screens. The Supplemental Review process includes three additional screens—the Penetration Screen, the Voltage and Power Quality Screen, and the Safety and Reliability Screen. If the DER passes all the additional screens, then the utility must allow the DER to interconnect without additional studies.

[7] The screening criteria are conceptually similar for small generator and net metering facilities in that the screens are intended to identify DERs that the utility can safely and reliably interconnect to its system without performing a comprehensive interconnection study. While the screens are conceptually similar, the details differ depending on whether the DER is a small generator subject to the Division 82 rules or a net metering facility subject to the Division 39 rules.

The Joint Utilities do not object to adopting a Supplemental Review process. Of the three screens IREC proposed, the Joint Utilities propose modifications to only one—the Penetration Screen. The Joint Utilities offer modest modifications to this screen to ensure that a proposed DER whose interconnection is approved under the Supplemental Review process will not compromise the safety or reliability of the utility's system. The Joint Utilities also propose minor revisions to the process for Supplemental Review.

A. Supplemental Review Penetration Screen

The Penetration Screen relies on the ratio of the interconnecting DER's generation to minimum load in the area to assess the likelihood that generation from the interconnecting DER will back-feed onto the distribution system, which would necessitate further study to determine whether additional protective measures are required. The Joint Utilities propose to modify the percentage of minimum load used in the Penetration Screen, to analyze feeders rather than "line sections," and to add language regarding consideration of non-exporting generation in minimum load calculations. The Joint Utilities also respond to REC's recommendations regarding minimum load data and consideration of existing projects.

1. The Percentage of Minimum Load used in the Penetration Screen Should be Reduced.

IREC recommends that the Penetration Screen level be 100 percent of the minimum load. This means if the aggregate export capacity in the applicable area, including the proposed interconnecting generator, is less than 100 percent of the minimum load in the area, then the applicant passes this screen, and the utility is required to automatically approve the interconnection

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without any additional study.[8] The Joint Utilities propose two critical revisions to the percentage threshold in this screen: (a) revise the Penetration Screen threshold to be 90 percent of the minimum load on the feeder or line section, and (b) revise the Penetration Screen threshold to be 80 percent of the minimum load for a feeder served by a dedicated substation transformer. Both Staff and IREC seek a detailed explanation for the Joint Utilities' proposal to reduce these thresholds.

a) Allowing Automatic Approval When the Generation is 100 Percent of the Minimum Load will Compromise System Reliability and Safety.

The Joint Utilities adamantly oppose the recommendation that the Penetration Screen be set at 100 percent of the minimum load. Requiring automatic approval without any additional study for a generator that could be equal to the minimum load on the interconnecting feeder would create significant risk to the distribution system. Additional study would identify protections that may be required to ensure safe and reliable system operations and should not be categorically precluded by virtue of an excessive Penetration Screen.

As an initial matter, setting the Penetration Screen at 100 percent leaves no room for error or even modest changes to load. If the aggregate export capacity of the feeder or line section is equivalent to 100 percent of the minimum load, then any incremental decrease in load would cause generation to flow off the feeder onto the broader distribution system and potentially the transmission system. Any scenario that creates the potential for backfeed requires the utility to do more comprehensive studies to understand and mitigate the impacts to the broader system.

An understanding of the current configuration of PGE's system helps highlight how

[8] The applicant would also need to pass the other Supplemental Review screens before the application would be approved.

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problematic a 100 percent threshold would be. Currently, PGE uses high-speed reclosing on feeder breakers for the first reclose interval. The high-speed reclosing has an open interval of six cycles (or 0.1 seconds), which, when combined with breaker operation time, is a total open time of 10 to 12 cycles (or 0.16 to 0.2 seconds). In other words, when a fault occurs, the recloser will open and then close within approximately 0.2 seconds.[9] High-speed reclosing often prevents sustained outages and reduces customer complaints because home electronics will ride through the high-speed reclose. However, island detection and separation on a DER can take up to 2.0 seconds. As proposed by IREC, if the generation-to-load ratio increases and approaches or exceeds the 100 percent threshold, island detection can significantly slow down due to the interaction of the island detection from various inverters,[10] which increases islanding risks (discussed above) and leads to longer outages.

Slower DER disconnections resulting from parity between generation and load can also create adverse conditions because of the types of inverters typically used for inverter-based resources (such as wind, solar PV, and batteries). On PGE's system, all inverters operate under a "grid following" control approach, in which the inverter measures the alternating current voltage waveform of the grid and responds by injecting current that matches the current on the grid. Unlike "grid forming" inverters that can independently "restart" the grid after an outage event, grid following inverters require the presence of the grid. When a circuit disconnects from the grid but a large solar resource on that circuit continues exporting, the solar resource can cause significant swings in local voltages. If the utility recloses prior to the solar resource disconnecting (as

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[9] Even when a utility uses voltage transformers to stall reclosing, the open interval is still 1.0 to 1.5 seconds—which is faster than the 2.0 seconds disconnect timing included in IREC's proposal.

[10] Sandia National Lab, *Unintentional Islanding Detection Performance with Mixed DER Types*, Aug. 1, 2018 (Available at: https://www.osti.gov/biblio/1463446/).

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discussed above), utility customers will experience voltage swings and other power quality issues as the large solar resource resyncs with the utility's system.

Lastly, if the utility were to extend the reclose interval to 2.0 seconds to account for the disconnection capabilities of the DER, this would benefit the DER but harm other customers who would experience longer outages and would have to reset electronic devices. As explained at the outset of these comments, DER interconnections should not degrade the existing system or compromise a utility's ability to provide safe and reliable service to existing customers. The Joint Utilities urge the Commission to adopt their recommended revisions to the percentage(s) of minimum load used in the Penetration Screen, because the utilities have ultimate responsibility for providing safe and reliable service and have explained in detail how safety and reliability would be diminished with use of a 100 percent minimum load screen. If the Commission imposes standards that result in a degradation to the service of other customers or threaten safety—such as requiring a 100 percent of minimum load screen—the Joint Utilities cannot be held responsible for negative impacts.

b) Establishing the Penetration Screen Threshold at Ninety Percent of Minimum Load Balances the Need to Ensure Reliability and Safety with Fast-Tracking DER Interconnections.

Setting the Penetration Screen threshold at 90 percent of minimum load ensures that the there is room to accommodate changes in load without compromising customer service. The 90 percent screen aligns with the Joint Utilities' existing, general practice of requiring protective equipment (either deadline checking, direct transfer trip, or both), if the aggregate generation on a feeder is greater than 90 percent of the minimum load. In the Joint Utilities' experience, a 90 percent screen reasonably ensures that there will be no adverse system impacts if a small DER is automatically approved for interconnection without further study.

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c) Establishing the Threshold at Eighty Percent where there is a Dedicated Transformer Balances the Need to Ensure Reliability and Safety with Fast-Tracking DER Interconnections.

For scenarios where the feeder is served by a dedicated substation transformer, the Joint Utilities propose revising IREC's proposed threshold of 100 percent down to 80 percent of the minimum load. A "dedicated" substation transformer is one where there is only one feeder going into the transformer. The Joint Utilities propose a lower threshold of 80 percent for this screen to ensure that the potential for backfeeding does not overwhelm the transformer and that if there is a possibility that reverse flow could reach the transformer, appropriate protective measures are in place. As background, distribution grounding is provided by the transformer, and during a transmission line phase to ground fault, the unfaulted phase voltages increase with respect to ground potential. If insufficiently grounded, the voltage of the unfaulted phase can rise up to 1.7 times normal, which is outside of the safe operation of the substation equipment. If the generation/load ratio is under 80 percent, the unfaulted phase voltage will remain at a tolerable level. However, if the generation/load ratio exceeds the 80 percent threshold, then the unfaulted phase voltage has the potential to affect safety and reliability, and the Joint Utilities' proposal will allow the utility to study the specifics of the interconnection and require appropriate protective measures. The 80 percent threshold is consistent with IEEE 1547.2-2018. However, the Joint Utilities are comfortable using 90 percent in situations where there are multiple feeders associated with a substation transformer because generation levels on feeders vary, and when one feeder has an issue, the other feeders can absorb excess generation to prevent reverse power flow.

2. Scope of Analysis

IREC's proposed Penetration Screen is based on 12 months of "Line Section minimum load data," with the "aggregate Export Capacity on the feeder or line section" being a certain

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percentage of the minimum load on the feeder.[11] Given that the proposed screen references both "line section" and "feeder," Staff seeks clarification regarding whether "line section" or "feeder or line section" are recommended for use in screen calculations. The Joint Utilities propose the use of the term "feeder" because line sections may not provide the quantity and quality of data needed to accurately calculate minimum loads. Line sections typically do not have the metering and telemetry that would be available at feeders, thereby limiting available data.

3. Time Period for Determining Daytime Minimum Load for Solar Resources

For the Penetration Screen, minimum load is based on the absolute minimum load for all resources except for solar projects. IREC recommends that for solar projects with no battery storage, the screen would be based on daytime minimum load calculated over 10 am to 4 pm for fixed-panel systems and 8 am to 6 pm for tracking systems.[12] Currently, the Joint Utilities define daytime minimum load as follows:

Utility	Tracking	Fixed Panel
Portland General Electric	9:00 am - 5:00 pm	9:00 am - 5:00 pm
PacifiCorp	9:00 am - 6:00 pm	9:00 am - 6:00 pm
Idaho Power[13]	8:00 am - 6:00 pm	10:00 am - 4:00 pm

The Joint Utilities understand that FERC's Small Generator Interconnection Procedures (SGIP) require the two-timeframe approach proposed by IREC. Because the Joint Utilities currently implement the two-timeframe approach required by FERC's SGIP, IREC's proposal is reasonable

[11] *See* IREC Supplemental Review, Section 3.A. - Supplemental Review Penetration Screen.
[12] Any rules implementing this requirement should also clarify that the time zone applicable in the area of the interconnection should be used. This clarification is necessary because a portion of Oregon is in the Mountain Time Zone.
[13] Idaho Power's daytime hours are Mountain Time Zone.

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and not unduly burdensome.

4. Consideration of Non-Exporting Generation in Minimum Load Calculation

IREC recommends that load that is co-located with a non- or limited-export project should be accounted for in the Penetration Screen.[14] The Joint Utilities generally agree with this recommendation but propose the following additional language: "The utility may take the impacts of non-export or limited-export generation on the calculation of minimum load into account when evaluating potential system impacts." The Joint Utilities are concerned that new non-exporting projects could cause backflow issues on a line that has existing exporting generation, even when the new generation only offsets onsite load.

For example, consider a hypothetical feeder that has a total load of 3 MW and a 2 MW generator interconnected (*i.e.*, leaving a minimum load of 1 MW). Later, if a customer on this feeder seeks to install a non-exporting 2 MW solar project, then the utility cannot automatically approve the interconnection of the new solar project even though it is non-exporting and would pass the Penetration Screen, as proposed by IREC. In this scenario, additional study is required because the effect of the proposed new 2 MW non-exporting generation is a net negative load (*i.e.,* potential for backfeed) on the feeder of 1 MW. In this scenario, the Supplemental Review process must be clear that the utility can study the impact of the new 2 MW interconnection.

Following the September 14, 2022, meeting, Staff requested the Joint Utilities clarify whether this provision is targeted at "existing generation or Applicant or both." This provision is intended to allow the utility to comprehensively study new generation proposed by an applicant, not to retroactively re-study existing generation. In the example discussed above, the newly

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[14] *See* IREC Supplemental Review, Section 3.A.ii.

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proposed 2 MW non-exporting generation would be subject to additional study and would not be allowed to automatically interconnect. The interconnection study for the new 2 MW non-exporting generation would identify any protective measures required to safely and reliably interconnect, accounting for the fact that the presence of the new 2 MW non-exporting generation will cause the existing 2 MW generation to exceed the feeder's new minimum load.

5. Extent of Data Used in Calculating Minimum Load on Feeder

IREC and the Joint Utilities recommend using 12 months of data, if available, to calculate (or estimate) the minimum load for purposes of the Penetration Screen. REC expressed concern about using only 12 months of data and advocates that the interconnection customer retain the right to request the use of a longer analysis window (*i.e.*, 13-24 months) to determine the minimum load. In its email from September 7, 2022, REC stated that "temporal circumstances related to local supply and demand on the grid and utility operations" will have an impact on the minimum load. REC believes that allowing for a longer period will account for potential anomalies in a single year's load data or allow the utility to determine if other circumstances not due to the proposed interconnection have caused similar impacts (*i.e.,* instances of reverse power flow through a substation transformer prior to the interconnection request due to a scenario such as reduced load from an outage or a weather event).

The Joint Utilities oppose REC's proposal for three reasons. First, in determining minimum load, the Joint Utilities already review the available data and remove anomalies to ensure that the minimum load calculation is reasonable and aligns with normalized system conditions. Therefore, additional data is not required to address anomalies. Second, introducing ambiguity regarding how much data must be used to determine minimum loads is likely to create disputes and undermine the Supplemental Review's streamlined process. Third, using older data likely

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decreases accuracy because system topology changes over time, resulting in both increases and decreases in load and DER generation. For these reasons, the Joint Utilities support the provision as currently written and oppose providing the interconnection customer the discretion to expand the timeframe of the minimum load calculation.

6. Source of Minimum Load Data for Screening Calculations

a) Applicant's Access to Data Used by Utility

REC also expressed concern that the Supplemental Review process would limit an applicant's ability to access, review, and verify daytime minimum load calculations, and in an effort to "ensure transparency," REC sought to confirm that the applicant will have access to this information. REC recommends that the Supplemental Review language be revised to specifically provide these interconnection customers' rights. The Joint Utilities take no issue with this request, subject to potential limitations if the minimum load data contains identifiable individual customer data.

b) Use of Actual Data

Additionally, in its email from September 7, 2022, REC requested clarification regarding "what happens when actual data is available and whether that would be used instead to calculate daytime minimum load." REC proposes that the "interconnection customer should have the option to require a utility to provide and use actual data." The Joint Utilities generally agree with this recommendation, as the Joint Utilities already use actual data, where available. Where sufficient actual data is not available—for example, on a new feeder—the Joint Utilities use the best information available to estimate the minimum load.

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7. Additional Consideration of Existing Project Export Capacity

When evaluating aggregate export capacity for the purposes of the Penetration Screen, IREC and the Joint Utilities recommend that existing project export capacity not be considered in the aggregate export capacity if the existing project export capacity is already reflected in the minimum load data (*e.g.*, generation like a combined heat and power (CHP) facility). In its email from September 7, 2022, REC recommends elaborating on other existing project export capacity that should not be considered in the aggregate export capacity. Specifically, in its redlines from October 4, 2022, REC proposes adding "and behind-the-meter or net-metered capacity" following the listed CHP facility capacity. The Joint Utilities do not object to this clarifying language.

B. Process for Supplement Review

1. Initiating Supplemental Review Should Require a Written Agreement.

The Joint Utilities agree to provide the option for an applicant to proceed to the Supplemental Review process if the applicant fails one or more of the currently applicable screens. The Joint Utilities further agree with IREC that if a request for Supplemental Review is not received from the applicant within 10 business days of the applicant receiving notification that it has failed the pre-existing screens, the application will be withdrawn.

The Joint Utilities recommend an additional requirement if the applicant requests Supplemental Review—the applicant seeking Supplemental Review must execute a Supplemental Review Agreement. Requiring an *agreement*, instead of simply notice, is generally consistent with the Commission's existing rules.[15] The Joint Utilities' proposed process for initiating Supplemental Review would be as follows:

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[15] *See, e.g.,* OAR 860-082-0060(6)(c), 7(c), and 8(c).

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- Applicant submits an interconnection application, and upon review by the utility, applicant fails an applicable pre-existing screen(s).
- The utility provides written notification to the applicant that it failed a pre-existing screen(s) and that the applicant may seek Supplemental Review or request that the utility continue evaluating the application under the utility's comprehensive interconnection study process.[16]
- Upon receipt of the notification regarding the availability of Supplemental Review, the applicant has 10 business days to accept this option; should that time lapse, the application is automatically withdrawn.
- Once the utility receives written notification from the applicant that it wishes to proceed with Supplemental Review, the utility provides the applicant a Supplemental Review Agreement.
- Following receipt of the Supplemental Review Agreement, the applicant has 15 business days[17] to submit a signed copy of the Agreement with the associated fee.
- If the applicant does not provide the signed Agreement and fee within that 15-business-day timeframe, the application is withdrawn.
- In the alternative, the applicant can notify the utility within that timeframe that it intends to forgo Supplemental Review and proceed with an interconnection study.

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[16] IREC's proposal refers to continuing to the "Level 4" study process if the applicant chooses to forgo Supplemental Review or if the applicant fails Supplemental Review. IREC's reference to "Level 4" is confusing because the Commission's net metering interconnection rules refer to "levels," but do not have a "Level 4," while the small generation interconnection rules refer to "tiers." For simplicity, these comments simply refer to additional interconnection studies that would follow an applicant's failure of either the pre-existing screens or the new screens included in the Supplemental Review process.

[17] The Joint Utilities propose extending this timeline to 15 business days to align with analogous timelines in the existing rules.

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In IREC's original draft proposal, IREC contemplated a "written agreement" following notification from the applicant that it wishes to pursue Supplemental Review.[18] However, in response to the Joint Utilities' proposed revisions and at the September 14, 2022, workshop, IREC expressed concerns regarding the requirement to complete a Supplemental Review Agreement. Instead, IREC now proposes that written notification, rather than a written agreement, be required to make the Supplemental Review process quicker and less cumbersome. However, the Joint Utilities maintain that Supplemental Review should proceed under an agreement to establish clear obligations and expectations upfront, which will minimize the likelihood of disputes.

By requiring an agreement, the Supplemental Review process will be no different from other interconnection study agreements and processes under the Commission's existing rules. There is no need to deviate from the established practice for purposes of Supplemental Review. In fact, the need for clarity is particularly acute for Supplemental Review because it is unclear whether the Supplemental Review process will be included in the existing interconnection rules or set forth in some other manner, such as a Commission-approved interconnection manual. Moreover, the time it takes the applicant to review, sign, and return a standardized agreement should not significantly differ from the time it takes the applicant to prepare and send a written notification to the utility.

2. Failure by Applicant to Respond Should Result in Withdrawn Application.

IREC raises concerns regarding the Joint Utilities' proposed revisions, which require that the application be withdrawn when the applicant does not timely complete the Supplemental

[18] Specifically, IREC proposed that the applicant shall agree in writing and "pay a Supplemental Review fee," further noting the implications for the applicant "[i]f the *written agreement* and fee have not been received." (emphasis added). IREC Supplemental Review, Section 2.

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Review Agreement, unless the applicant has notified the utility that it wishes to continue through the interconnection study process. IREC recommends that if the applicant has notified the utility that it wishes to proceed with Supplemental Review but fails to provide a signed copy of the agreement within the required timeframe, then the default should be that the application continues to the utility's more comprehensive interconnection review process, rather than being automatically withdrawn.

However, the Joint Utilities' proposal is consistent with the interconnection processes in the Commission's existing rules under which an applicant's failure to respond in the timeline required by the rules results in the application being withdrawn,[19] and applications are not automatically moved to a higher level of review.[20] The Joint Utilities are concerned that IREC's proposal would create confusion because it simply assumes that an applicant that has failed to respond is interested in pursuing a likely more expensive and time-consuming level of review without the applicant's express approval. As a general matter, an applicant that does not go through the Supplemental Review process will need to enter the utility's more comprehensive interconnection study process (*i.e.*, Feasibility Study, if applicable, Cluster or System Impact Study, and Facilities Study), and that process will certainly take more time and cost more than the Supplemental Review process.

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[19] *See, e.g.*, OAR 860-082-0025(7)(a)(A) (if utility deems application incomplete, applicant must provide required information within 10 business days or the application is deemed withdrawn); OAR 860-082-0025(7)(e) (applicant must return signed interconnection agreement or request to negotiate within 15 business days or application is deemed withdrawn); OAR 860-082-0060(6)(c) (application must return signed feasibility study agreement within 15 business days or application is deemed withdrawn).

[20] *See, e.g.*, OAR 860-082-0045(5) ("If a small generator facility is not approved under the Tier 1 interconnection review procedure, then the applicant may submit a new application under the Tier 2, Tier 3, or Tier 4 review procedures.").

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V. CONCLUSION

The Joint Utilities look forward to continuing to work with Staff and stakeholders to refine the Export Control and Supplemental Review proposals and answer any remaining questions. The Joint Utilities request that Staff or the Commission clarify whether, when, and how the proposed documents will be incorporated into the Commission's existing rules.

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