Office of the Secretary
Service Date
March 9, 2021

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S APPLICATION TO ESTABLISH TARIFF SCHEDULE 68 – INTERCONNECTIONS TO CUSTOMER DISTRIBUTED ENERGY RESOURCES	)))))	**CASE NO. IPC-E-20-30** **ORDER NO. 34955**

On July 20, 2020, Idaho Power Company ("Idaho Power" or "Company") applied for authority to establish tariff Schedule 68, Interconnections to Customer Distributed Energy Resources ("Schedule 68"). On August 13, 2020, the Company filed a Supplemental Application that included proposed tariff updates for Schedules 6, 8, and 84, which reference the proposed Schedule 68.

On August 27, 2020, the Commission issued a Notice of Application and Notice of Intervention Deadline. Order No. 34763. Idaho Conservation League ("ICL"), Idaho Sierra Club, and Idaho Clean Energy Association timely intervened.

On October 20, 2020, the Commission issued a Notice of Modified Procedure setting comments and reply deadlines. Order No. 34817. Commission Staff, ICL, Idaho Sierra Club, and Idaho Clean Energy Association filed timely comments, and the Company filed a timely reply.

Now, having reviewed the record, the Commission enters this Order approving the Company's Application.

BACKGROUND

The Company's filing responded to Commission orders in Case No. IPC-E-17-13. In IPC-E-17-13, the Commission found that "smart inverters provide functionality that is beneficial to support the ongoing stability and reliability of the Company's distribution system. Therefore, we find that the industry's adoption of a smart inverter requirement will mitigate circuit voltage deviation in a cost effective manner and is therefore reasonable." Order No. 34046 at 20. The Commission ordered the Company to file proposed smart inverter requirements with the Commission within 60 days after the Institute of Electrical and Electronics Engineers ("IEEE") adopted IEEE Standards 1547 and 1547.1. Order No. 34046 at 31. On reconsideration, the Commission found it reasonable to let customer-generators opt to remain on Schedule 1 or 7 if the customer-generators "can reasonably and safely eliminate the export of energy to the Company's grid." Order No. 34147 at 15-16. The Commission went on to state, "Consequently, alongside the parameters set forth in Order No. 34046, a non-export option should be studied for feasibility and vetted for safety and operational concerns by the Company and interested stakeholders in the forthcoming docket." Order No. 34147 at 16.

The IEEE 1547 Standard for Interconnection and Interoperability of Distributed Energy Resources with Associated Electric Power Systems Interfaces was published in 2018. The IEEE Standard 1547.1 Conformance Test Procedures for Equipment Interconnecting Distributed Energy Resources with Electric Power Systems and Associated Interfaces was published May 21, 2020.

THE APPLICATION

The Company stated in its Application that the proposed Schedule 68 contains provisions and requirements for incorporating smart inverters consistent with the adopted IEEE standards, and provisions and requirements for non-export customer-generators and energy storage devices. Idaho Power Application at 2. The Company proposed to remove all interconnection requirements applicable to retail customer-generators that take service under Schedules 6, 8, or 84 from Schedule 72 and place them in the proposed Schedule 68 with modifications intended to clarify and streamline the customer-generator interconnection process. Idaho Power Supplemental Application at 2. The Company summarized its proposed changes to the customer-generator interconnection process as:

> (1) Modified or added language intended to improve clarity for the Company in administering and for customers and installers in complying with the tariff schedule, (2) removed the three-year recertification requirement, (3) added flexibility of additional time, only as needed, to complete Feasibility Reviews, (4) modified requirements in the unauthorized systems and expansions section, and (5) implemented a return-trip charge if the Company is unable to complete an inspection.

Aschenbrenner, Di. at 16. The Company proposed no changes to Schedule 72 for the interconnection of Public Utility Regulatory Policies Act of 1978 qualifying facilities. *Id.* at 13-14.

The Company described a smart inverter as "an inverter that provides configurable functions beyond [converting] DC to AC. A few . . . features are voltage/reactive power control, anti-islanding, monitoring, and remote communication." Ellsworth, Di. at 11. The Company proposed smart inverters be set for IEEE 1547-2018 performance Category B with reactive power mode set to voltage-reactive power. *Id.* at 13. The Company proposed smart inverters be set to use IEEE 1547-2018 Category III Voltage Ride-Through settings. *Id.* at 14. The Company proposed the remaining smart inverter settings be set to the default values specified in IEEE 1547. *Id.*

The Company described the benefits of smart inverters and how distributed energy resources ("DERs") affect distribution circuits. *Id.* at 7-10. The Company explained that before DERs, "the distribution system could be characterized as a downhill flow of power from electrical substations, across distribution circuits, to customers." *Id.* at 7. The voltage would reduce as energy traveled further from the distribution substation. *Id.* The American National Standards Institute ("ANSI") Standard C84.1 Range A "specifies that voltage provided to customers must be in the range of plus or minus five percent of the nominal voltage, i.e., 0.95 – 1.05 per unit ('pu')." *Id.* DERs can change a distribution system's downhill power flow into a two-way power flow. *Id.* at 8. The Company stated, "In most installations, this dynamic is inconsequential; however, there are cases where DERs can negatively impact the performance of a distribution circuit. Two such cases are (1) voltage rise causing high voltage and (2) voltage deviation." *Id.* The Company explained that voltage rise occurs when "customer generation exceeds customer demand, and power flows back toward the substation transformer." *Id.*

> A typical voltage profile for a distribution circuit begins with a maximum voltage, approximately 1.03 pu, at the distribution transformer, and voltage will reduce with the distance from the substation. For distribution circuits with high penetrations of customer-owned DERs, the 0.02 pu difference between the 1.03 at the distribution substation, and the 1.05 ANSI Range A maximum voltage, can provide challenges in integration.

Id. The Company explained other options to address voltage rise and concluded that smart inverters are the most economical solution. *Id.* at 9. The Company described voltage deviations that can be caused by DERs:

> Distribution circuits have devices such as load tap changers, regulators, and shunt capacitors, that are installed to manage the voltage at various points on the distribution circuit. These devices respond to voltage changes over a few seconds. The output from a solar PV system changes more rapidly than can be managed by the distribution devices, impacting other customers in the near proximity.

Id. at 10. The Company stated that voltage deviation issues often result from DER customers, particularly where DERs are highly deployed, and that smart inverters are the most cost-effective solution to voltage deviation. *Id.*

The Company described its proposed smart inverter functionality to maintain normal operating voltage within the acceptable range:

> The reactive power control setting will be a voltage-reactive function with a voltage dead band between 0.98 and 1.03 pu. When the voltage falls below the dead band, 0.98 pu, the volt-ampere reactive ('var') requirements will go from 0 to a maximum var requirement of 44 percent of nameplate kilo-volt-ampere ('kVA') injecting at 0.92 pu. When the voltage rises above the dead band, 1.03 pu, the var requirement will go from 0 to a maximum of 44 percent of nameplate kVA absorbing at 1.06 pu.

Id. at 13. The Company explained that it "selected the 0.98 to 1.03 pu dead band to maximize the amount of time inverter-based DERs spend within the dead band, in other words, operating at unity power factor, while still allowing for voltage support during times of need." *Id.* The Company explained its decision to recommend a minimum voltage setting of 0.92 and a maximum voltage setting of 1.06, which are outside the ANSI C84.1 Range A service voltage settings of 0.95 to 1.05 pu. The Company explained,

> The 0.92 and 1.06 pu voltages represent approximations to ANSI standard C84.1 Range B. Range B specifies a wider allowable service voltage range to customers; however, service voltages outside the 0.95 to 1.05 Range A limits should be infrequent, per the standard. These lower and higher limits in the smart inverters allow for var support over a wider range of voltages and ensure the need to supply maximum var support, injecting or absorbing, will be infrequent.

Id. at 13-14. The Company stated solar PV system efficiencies will be negligibly affected because distribution circuits rarely operate outside the voltage dead band between 0.98 and 1.03 pu and absorbing or providing vars when outside the dead band will require little to no reduction in the customer-generator's output. *Id.* at 14-15.

The Company's Application included a non-export option for customer-generators who wish to interconnect a non-exporting system in parallel to the Company's system and remain on their current retail schedule. The Company stated that the non-export proposal resulted from the settlement agreement and related discussions with stakeholders in IPC-E-18-15 and IPC-E-19-15.

Aschenbrenner, Di. at 10-12. The Company stated its non-export proposal "balances providing enhanced customer optionality while mitigating and monitoring system impacts that may ultimately impact other customers." *Id.* at 12. The Company further explained, "The same general requirements would apply to net metering exporting systems and non-exporting systems, including disconnection equipment, metering equipment, and smart inverter requirements. For non-exporting systems under 3 megavolt-ampere ('MVA') total nameplate capacity, the application process will also generally be the same as those for exporting systems." Ellsworth, Di. at 18. The Company's Application provided three options for non-export systems: (1) advanced functionality, (2) reverse power protection, or (3) minimum power protection. *Id.* at 18. These options are explained in greater detail in Jared Ellsworth's direct testimony in support of the Application. *Id.* at 18-21.

The Company proposed no limit on the nameplate capacity for non-exporting systems for commercial, industrial, and irrigation customer-generators. *Id.* at 21. The Company proposed a 25 kVA nameplate capacity limit on residential and small commercial non-export customer-generators that take service under Schedules 1 or 7. *Id.* The Company stated Schedule 1 and 7 customers would not likely have a large enough load to warrant a system larger than 25 kVA to offset their consumption and placing a 25 kVA cap on Schedule 1 and 7 customers would align with the Schedule 6 and 8 size requirements, allowing customers to transition between the net metering and non-export service schedule. *Id.*

The Company proposed to require protection equipment, metering, and communication equipment for non-export systems 3 MVA or larger. *Id.* at 22. The Company also stated that rotating machines up to 500 kVA and inverter-based DERs up to 3 MVA would be evaluated case-by-case. *Id.* The Company explained that rotating machines on the distribution system have a higher fault current contribution and that a 3 MVA or greater DER would make up at least 30% of a typical distribution circuit's capacity. *Id.* Therefore, these larger DERs could affect distribution circuit voltage levels and impact operational safety and distribution circuit reliability. *Id.* at 22-23. The Company stated that a 3 MVA or greater DER can absorb or supply 1.3+ mega-var of reactive power, which can significantly impact the voltage on the distribution system. *Id.* at 23. The Company stated that protection equipment "provides a means to coordinate distribution circuit protection, such as circuit breakers, reclosers, and fuses." *Id.*

The Company stated that it proposed metering and communications equipment for larger DER systems to provide operational visibility for functions such as scheduling, dispatching, and load balancing. *Id.* at 23-24. The Company stated that customers seeking to interconnect a 3 MVA or greater non-export DER system may have to pay for one or more studies besides the Feasibility Review completed for all DERs, which may include a Feasibility Study, System Impact Study, and/or a Facility Study. *Id.* at 25. Thus, the Company proposed that a non-export DER system 3 MVA or greater must complete a full Customer-Generator Interconnection Process and sign a uniform interconnection agreement, the same as any other generation system interconnected under Schedule 72. *Id.* at 25-26.

The Company stated that its proposed interconnection process recognizes that non-export DER systems 3 MVA or greater must have similar performance characteristics as other generation systems interconnected under Schedule 72. *Id.* The Company stated, "An example of this is during a transient condition that results in extremely low voltage (down 0.88 to 0.50 pu); the non-exporting system is required to continue operation for up [to] 20 seconds. The non-exporting system operation, combined with other on-grid DERs, is required to remain connected to avoid a sustained system outage." *Id.* at 26. The Company proposed that a non-exporting system 3 MVA or greater will not need to enter Idaho Power's generation interconnection queue. *Id.* The Company proposed that a customer-generator interconnecting a non-exporting system 3 MVA or greater would have to buy a Company-installed system protection package. *Id.* at 27. The customer-generator would pay the Company a maintenance charge of 0.59% of the cost of the protection package per month. *Id.* Rather than requiring a non-export customer-generator to fund upgrades to the Company's distribution system if the non-exporting system total nameplate capacity exceeds the capacity of the local distribution facilities, the Company proposed to require a customer to replace any damaged equipment if the non-export control system fails and damages the Company's system. *Id.* at 27-28.

To ensure non-export systems do not export energy that could damage the Company's system, the Company proposed to define unauthorized inadvertent export as "the total exports in any 30-day period exceeding three hours of the total nameplate rating. . . . As an example, a 10 kVA AC system would be limited to 30 kWh of export in 30 days. If more than 30 kWh of export occurs, the non-export control system would have failed." *Id.* at 28. If an unauthorized inadvertent export were to occur, the Company would notify the customer-generator and provide a 30-day cure period for Schedule 1 and 7 customer-generators. *Id.* If not cured within 30 days, the customer-generator could disconnect its non-export system and fix the problem. *Id.* at 29. Idaho Power would then inspect the non-exporting system and reconnect it under Schedule 1 or 7. *Id.* Or the customer-generator could apply to take service under Schedule 6 or 8 if they are eligible. *Id.* After 180 days on Schedule 6 or 8, the customer-generator could reapply to move back to Schedule 1 or 7 as a non-exporter. *Id.* For customer-generators not on Schedule 1 or 7, the customer-generator would have to disconnect their system upon notification from Idaho Power that there had been unauthorized inadvertent export, fix the problem, and have Idaho Power inspect the system before reconnecting to the Company's system. *Id.*

The Company did not propose additional interconnection requirements for energy storage devices DC Coupled to a generation system (shared inverters). *Id.* at 30. The system size for shared inverter systems would be determined by the inverter nameplate rating. *Id.* at 30. Energy storage devices AC Coupled to a generation system (separate inverters), would be treated as separate DERs and the customer-generator would have to separately apply and go through a separate interconnection review for the energy storage system and the generation system. *Id.* The system size for separate inverter systems would be the aggregate value of the inverter nameplate ratings at the premise. *Id.* If the customer-generator wants to ensure that an energy storage device would not export to the Company's grid, the customer-generator would have to implement advanced functionality, as described on page 19 of Jared Ellsworth's direct testimony in support of the Application. *Id.* at 31.

COMMENTS

A. <u>Commission Staff.</u>

Staff recommended the Commission approve the Company's Application. Staff Comments at 2. Staff advised that the Company's proposed use of smart inverters would not adhere to the communications protocols specified in IEEE 1547-2018. Thus, the smart inverters may not fully function as contemplated in IPC-E-17-13. *Id.* at 4. Staff stated the proposed smart inverter settings would control voltage and protect the system. *Id.* But potential benefits like scheduling, dispatching, load balancing, and forecasting are impossible without real-time or near real-time communications protocols, and the Company's proposal does not require those protocols for systems smaller than 3 MVA. *Id.* To implement communications protocols later, each smart inverter would need to be manually reprogrammed and would likely be required to be connected to the internet. *Id.*

Staff supported the Company's proposed reactive power, ride-through, and anti-islanding settings. Staff stated, "The reactive power settings specified by the Company will allow the inverter to control voltage and either supply or consume reactive power with little or no impact on either the power consumed on-site by the customer or exported to the Company's system." *Id.* Staff explained, "[IEEE 1547-2018 performance] Category B is more stringent than Category A, and requires the DER to be able to either absorb or inject more reactive power than Category A. Category B settings are intended to provide enough reactive power control to maintain grid stability, even when DER penetration is relatively high." *Id.* at 5. Staff stated that if the smart inverter is sized to meet the DERs' real and reactive power needs, then the smart inverter can control voltage without curtailing the quality or quantity of power available to the customer for use or export. *Id.* Staff supported the Company's proposal to use voltage dead band settings that differ slightly from those recommended in IEEE 1547-2018 to align the smart inverter parameters with the parameters for the Company's existing infrastructure. *Id.* Staff stated the Company's proposed ride-through settings "conform with industry best practice for DER systems operating without a communication interface that would allow the Company to detect and coordinate responses to abnormal voltage deviations." *Id.* at 6. Staff agreed with the Company's proposal to use IEEE 1547-2018 anti-islanding protocols. *Id.*

Staff concurred with the Company's proposal to allow existing inverters to continue until they need to be replaced, at which time they must be replaced by a smart inverter. *Id.* at 7. Staff stated, "Currently, no portion of Idaho Power's grid has a sufficiently high DER density to cause instability related to a deficiency of reactive power, and there have been no reports of islanding. Furthermore, Staff was unable to determine that smart inverters provide any quantifiable system-wide benefit when DER penetration rates are low." *Id.* at 7. Staff thus concluded that requiring existing customer-generators to retrofit their systems with smart inverters would be an unnecessary expense. *Id.*

Staff stated that the Company plans to use Underwriters Laboratories ("UL") certification UL 1741 SB to determine whether to approve a smart inverter, but UL 1741 SB has not been finalized. *Id.* Meanwhile, the Company would use a supplemental list, UL 1741 SA, to determine whether a smart inverter is approved, and if the smart inverter is not on UL 1741 SA, the Company would make a case-by-case determination. *Id.* Staff verified that sufficient quantities of UL 1741 SA compliant smart inverters are available in the market to meet foreseeable demand. *Id.*

Staff reviewed the Company's non-export option and concluded that it is "reasonable, that it adequately protects the Company's system, and that it provides Customer-Generators a low-cost way to generate their own power while remaining on Schedules 1 and 7." *Id.* at 8. Staff reviewed the Company's energy storage device proposal and concluded "both the DC Coupled and AC Coupled configurations will provide DER customers a means for storing the energy they produce while protecting the grid." *Id.*

B. Idaho Conservation League.

ICL recommended the Commission approve the Company's proposals and made additional recommendations. ICL recommended the Company clarify how it intends to ensure that the correct inverter settings have been applied upon installation and recommended that the Company provide educational materials and trainings for installers to ensure adherence to Schedule 68. ICL Comments at 1, 3. ICL also recommended the Commission direct the Company "to monitor the growth of [DERs] and report annually in the Demand Side Management report on opportunities to implement additional smart inverter functions and address distribution circuits experiencing reliability issues." *Id.* at 1, 4. ICL stated it reviewed the Company's proposal "with an eye on . . . ease of implementation, impact on power quality, and the impact on customer-owner." *Id.* at 2. ICL also consulted Grid Lab about Idaho Power's proposal. *Id.* ICL stated, "Overall, our review shows Idaho Power's proposed settings are easy to implement, will improve power quality, and will not negatively impact customer-owners." *Id.*

ICL supported Idaho Power's proposed non-export options for systems up to 3 MVA but recommended the Commission direct Idaho Power to only require additional metering and communications equipment for 3 MVA or larger non-export systems if a site-specific interconnection study reveals the additional equipment is necessary to avoid unreasonable impacts to the electric system. *Id.* at 2-3. ICL supported the Company's proposal to not apply additional interconnection requirements for DC Coupled or shared inverter energy storage systems. *Id.* at 3.

C. Idaho Sierra Club.

Idaho Sierra Club's comments focused on the potential growth of DERs on Idaho Power's system, particularly in the agricultural sector, as technology advances and costs decline, and expressed concerns that Idaho Power's proposed approach may end up prohibiting growth after a significant increase in DER penetration. Idaho Sierra Club stated, "While it may be adequate in the short-term, we don't believe that the passive approach Idaho Power has proposed in this docket (just setting a dead band on smart inverters without committing to promptly begin studying how to better utilize DERs) is in the longer-term interest of the Idaho public." Idaho Sierra Club Comments at 3-4.

D. <u>Idaho Clean Energy Association.</u>

ICEA stated it agrees with the ICL and Sierra Club comments and looks forward to working with the Company and stakeholders to implement proposed Schedule 68. ICEA Comments at 1.

COMPANY REPLY COMMENTS

In reply, the Company provided additional context regarding compliance with Commission Orders in IPC-E-17-13 and responded to party recommendations about smart inverters, the non-export option, and implementation. The Company stated its proposal would achieve the potential benefits it presented to the Commission in IPC-E-17-13. Idaho Power Reply Comments at 3-4. The Company stated that its proposed settings "will improve power quality and provide the opportunity for customers to expand the interconnection of DERs for the long-term interest of the system without requiring costly system upgrades to address issues such as voltage rise." *Id.* at 4. The Company stated its proposal is thus consistent with the functionality the Company presented to the Commission in IPC-E-17-13.

In response to ICL's recommendation that the Commission only require additional metering and communications equipment for non-export systems 3 MVA and larger if a site-specific study concludes the extra metering and equipment is required, the Company stated: "the requirement for metering and communications equipment is necessary to provide operational visibility of the customer generation to ensure critical system operational functions." *Id.* at 5. The Company stated that visibility is required for the scheduling, dispatching, and load-balancing functions entrusted to Idaho Power as a balancing authority in the Western Electricity Coordinating Council. *Id.* Idaho Power maintained that actual data from systems 3 MVA and larger is critical for an accurate load and resource forecast. *Id.* The Company stated that real-time information from larger systems helps the Company comply with North American Electric Reliability

Corporation's reliability requirements. *Id.* In sum, the Company stated that it cannot manage its system safely and reliably unless these systems are operationally visible. *Id.* at 6.

In response to ICL's recommendations to train installers and ensure correct software settings, the Company agreed that educating and training installers in its service territory is necessary to streamline a transition to the new DER interconnection requirements. *Id.* at 6. The Company detailed its plan to provide materials to known installers in its service territory through email notices, updated materials on its website, and offering virtual training sessions with installers to review the interconnection requirements and answer questions. *Id.* at 6-7. The Company stated it would rely on information from customer-generators' System Verification Forms to assure the correct software settings have been implemented but would request documentation if necessary. *Id.* at 7. The Company stated it does not oppose yearly reporting on DER growth in its service area, but that it would be better to add that information to its Net Metering Report than to its Demand Side Management Report. *Id.*

COMMISSION FINDINGS AND DECISION

The Commission has jurisdiction over this matter under *Idaho Code* §§ 61-501, -502 and -503. The Commission is empowered to investigate public utility rates, charges, rules, regulations, practices, and contracts and to determine whether they are just, reasonable, preferential, discriminatory, or in violation of any provision of law, and to fix the same by order. *Idaho Code* §§ 61-502 and 61-503.

Having reviewed the record, the Commission finds the Company's Application to be fair, just, and reasonable, and thus approves it. We anticipate that Schedule 68 will increase DERs in Idaho Power's service territory without compromising distribution system reliability.

We find it prudent to require that the Company's annual Net Metering Report include any known or foreseeable DER related distribution circuit issues or costs and potential smart inverter functionality updates that could address the issues or lower the costs. The Net Metering Report should be the primary means by which the Company apprises the Commission of these issues, but we also find it reasonable to direct the Company to include information on distribution-level DER impacts in its annual Demand Side Management Report. Through these additional reporting requirements, we can monitor potential DER issues and address them proactively without limiting DER growth. If it becomes evident that additional functionality requirements are necessary, such as implementing communications protocols, we can address those issues at the appropriate time without slowing or prohibiting DER adoption or requiring customers to incur unnecessary costs. We find that requiring the Company to implement communications protocols now for all new DER systems would be premature and unnecessarily costly.

The new interconnection requirements cannot be smoothly implemented unless the installer community is properly educated and trained. The Commission appreciates the Company's plan to provide materials and answer installer questions. But the Company should be sure not to assume any additional liability by certifying or appearing to certify that an installer is qualified because they have completed a training or received the educational materials.

ORDER

IT IS HEREBY ORDERED that the Company's Application is approved, effective 14 days from the service date of this Order.

IT IS FURTHER ORDERED that the Company include in its annual Net Metering Report and annual Demand-Side Management Report information as referenced in the Commission Findings and Decision section of this Order.

THIS IS A FINAL ORDER. Any person interested in this Order may petition for reconsideration within twenty-one (21) days of the service date of this Order with regard to any matter decided in this Order. Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. *See Idaho Code* § 61-626.

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DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 9th day of March 2021.

PAUL KJELLANDER, PRESIDENT

KRISTINE RAPER, COMMISSIONER

ERIC ANDERSON, COMMISSIONER

ATTEST:

Jan Noriyuki
Commission Secretary

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