Interconnection, Safety, Reliability and Advanced Inverters

Energy and Telecommunications Interim Committee
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Interconnection policies directly impact a customer generator's ability to net meter, and both safety and reliability are utility concerns when interconnecting net-metered facilities. The distribution systems owned by utilities are not typically designed to accommodate small net-metered facilities, and utilities often raise concerns about net-metered facilities having the potential to accidently energize circuits during an outage or to disturb a utility's ability to maintain reliable power – which it is tasked by regulators to do. Interconnection policies are designed to not only ensure the safety and reliability of the electric system, but also to provide customer-generators with a transparent process to follow in order to plug into a utility's distribution system. Interconnection discussed in this report is intended to capture the technical standards and procedures required for a customer generator using the system and to address how those standards are applied to net-metered facilities through utility and statutory policies.

Senate Joint Resolution No. 12 requests the Energy and Telecommunications Interim Committee (ETIC) review safety and system reliability issues related to net metering. The review is to include a discussion of the "tangible impacts to line personnel when operating the system with interconnected net metering systems; and testing frequency of devices required at net metered systems for line personnel and public safety, specifically testing requirements to prevent net metered systems from back feeding the grid during grid power disruptions."

SJ 12 also requests the ETIC to review the capacity of net metered systems that would necessitate real-time communication from net metering systems to the grid operator to properly operate the grid; and to assess the benefits, if any, of requiring smart inverters or reviewing electrical code standards to mitigate operational problems, if any, resulting from high saturation of the utility's power delivery system by net metering systems. This report discusses safety, broader operational matters, and the use of new technologies to address these issues.

<u>Interconnection Procedures</u>
In Montana the technical rules and procedures that allow a net-metered customer to interconnect with a utility's system are in 69-8-604, MCA. The Montana Public Service Commission (PSC) also has adopted rules for regulated utilities to follow for interconnection but not using its net metering rulemaking authority.[1] The PSC rules provide more clarity concerning a small generator's interconnection to the system. The statute reads:

> *(1) A net metering system used by a customer-generator must include, at the customer-generator's own expense, all equipment necessary to meet applicable safety, power quality, and interconnection requirements established by the national electrical code, national electrical safety code, institute of electrical and electronic engineers, and underwriters laboratories.*
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> *(2) The commission, after appropriate notice and opportunity for comment, may adopt by rule additional safety, power quality, and interconnection requirements for customer-generators that the commission or the local governing body determines are necessary to protect public safety and net metering system reliability.*

[1] Administrative Rules of Montana, 38.5.8401-38.5.814.

Standards and Guidelines for Safety

The information provided in this report focuses on interconnection in Montana. It is important to distinguish between net-metering (a billing arrangement allowing a customer-generator to realize savings from a small-generator) and interconnection (technical rules allowing a customer-generator to couple with the grid). Interconnection standards or procedures are required to ensure the safety of the public, emergency responders, and electric utility workers. These standards must protect the customer generator's assets, as well as the utility's assets. The majority of state and federal interconnection rules and procedures for net-metered facilities are based on safety and engineering standards from the Institute of Electrical and Electronic Engineers (IEEE) and Underwriters Laboratories (UL). They also incorporate the requirements of the National Electrical Code (NEC). While the standards are viewed as providing a baseline for interconnection and some technical considerations, the standards do not necessarily address broader interconnection issues.

Engineering standards in general, however, address safety and power quality issues raised by net metering.[2] States and utilities are not federally mandated to adopt the codes and standards, but most state laws or state utility commissions require at a minimum:

- IEEE 1547-2003, which provides technical requirements and tests for grid-connected operation;
- UL 1741, which certifies inverters, converters, charge controllers, and output controllers for power-producing stand-alone and grid-connected renewable energy systems. UL 1741 also verifies that inverters comply with IEEE 1547 for grid-connected applications; and
- National Electrical Code (NEC) requirements to address electrical equipment and wiring safety.

In general, one primary safety concern with net-metered facilities is verification that a facility will reliably trip off-line when there is a power outage. Additional utility concerns can include net metering systems causing an increase in fault current levels and voltage flicker problems.

Safety and reliability concerns can often be addressed by requiring verification that generation does not exceed a certain percentage of the minimum feeder load and by requiring customer generators to perform annual testing in which the net metered facility is disconnected from the public utility's equipment to ensure that the inverter stops delivering power to the grid. In addition, requirements can include a customer-generator perform all manufacturer-recommended testing or maintenance and require facilities include a lockable disconnect.[3]

Questions to Keep In Mind

Do Montana's current net metering laws and rules adequately address interconnection procedures for the current level of net metering?

If net metering increases in Montana should the current laws or rules be modified? If yes, how?

Nearly every utility requires a customer-generator meet the NEC and applicable state and local codes. Utilities and cooperatives in Montana are no exception. A significant number of utilities also require a manual, lockable disconnect switch that is accessible to utility workers. In most cases, utilities also require net metering facilities to be inspected and tested before being

[2] http://energy.gov/energysaver/articles/grid-connected-renewable-energy-systems

[3] Institute of Electrical and Electronics Engineers (IEEE). (2003) 1547---2003 IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems.

interconnected to the grid. Beyond the high-level requirements, utility requirements can vary greatly. For example, some utilities require each customer-generator to have a separate transformer and other utilities require synchronizing devices.

While some of the standards and procedures are also considered "universal", it is noteworthy that as technology advances and changes, standards and procedures don't always keep up. One solar power advocate, for example, reports that external disconnect switches are unnecessary and an additional cost for systems less than 10 kW. "This is because all inverters that meet IEEE standards automatically detect a power loss and shut down avoiding the safety concerns that a line worker will come into contact with a line energized by an interconnected PV system or other power producing distributed generation system."[4]

Beyond the standards and procedures, interconnection policies used in various states and by various utilities for net metering vary – sometimes greatly – in how those standards and procedures are applied to customer generators. Some utilities, for example, mandate liability insurance, property easements, and legal indemnification requirements. Metering calibration charges, engineering study fees, or standby charges also are required in some instances. Some public utility commissions and state legislatures, for example, have determined that liability insurance requirements are burdensome. Nevada's net metering statute specifically prohibits utilities from requiring additional liability insurance if a customer-generator meets applicable national and industry standards.[5] The Idaho Power Company, on the other hand, requires $1 million in liability insurance from customer generators.[6]

Some utility and state policies establish standard timelines for completion of steps required for interconnection. Montana's rules for regulated utilities include specific timelines for interconnection depending on the size of a system. The timelines are aimed at accommodating the needs of utilities to process requests while ensuring a customer-generator's request is handled within an appropriate timeframe. "For developers, the interconnection process is one of the most time-consuming and costly aspects of developing a generating facility."[7]

Montana Interconnection Agreements

In July 2010, the Montana Public Service Commission (PSC) adopted interconnection rules, effective August 13, 2010 for small generators. The rules were updated "to provide an efficient, transparent, and uniform process by which small generators may connect to the electrical grid and to implement Section 1254 of the Electricity Modernization Act of 2005". The rules don't precisely state that they apply to net metering, but the definitions in the rules address customer-generators' interconnection.

The rules, which appear to apply to both MDU and NorthWestern Energy, establish four levels of review for interconnection. Level 1 is a "fast track" review for systems that are 50 kW or less. Level 2 is an "expedited" review for systems 2 MW or less. Level 3 establishes a process for interconnection requests to radial distribution circuits where power is not exported. Aggregate

[4] "Freeing the Grid: Best Practices in State Net Metering Policies and Interconnection Procedures", Interstate Renewable Energy Council and Vote Solar Initiative, November 2012, page 18.
[5] NRS 704.774.
[6] https://www.idahopower.com/AboutUs/RatesRegulatory/Tariffs/tariffPDF.cfm?id=52.
[7] Kevin Fox, Sky Stanfield, Laurel Varnado, and Thad Culley, Keyes Fox & Wiedman LLP; Michael Sheerhan, Failte Group LLC, and Michael Coddington, National Renewable Energy Laboratory, "Updating Small Generator Interconnection Procedures for New Market Conditions," National Renewable Energy Laboratory, U.S. Department of Energy, December 2012, page 2.

load also must be less than 50 kW and use reverse power relays or other protection functions. Level 4 provides for interconnection under 10 MW that doesn't fall under the other three levels.

Net-metered facilities in Montana are limited in size to 50 kW for NorthWestern and MDU customers. More traditional net-metered customer-generators would likely interconnect using the Level 1 review process. The interconnection rules establish technical qualifications for a system 50 kW or less, including a requirement than small generators have an external utility disconnect switch for all interconnections.

Under Level 1, the aggregated generation on the line section, including the proposed small generator facility, may not exceed 15% of the line section's annual peak load as most recently measured at the substation or the annual minimum load of the line section. In addition, if the interconnection is proposed to a spot network circuit where total generation exceeds 5% of the spot network's maximum load, the generator must utilize a "protective scheme" to ensure that the flow does not affect network protective devices.

The interconnection rules for Level 1 also require a regulated utility to inform a customer-generator that the interconnection request is complete or incomplete within 10 days of receiving a request. Screens must be conducted by the utility within another 15 days to confirm that the small generator can be interconnected safely and reliably.

The rules also outline parameters for a utility that wishes to monitor and control a small generator. NorthWestern and MDU are only allowed to monitor and control the facility if the aggregate nameplate capacity of all small generators on the line section, in combination with the small generator facility seeking interconnection is greater than 15% of the line section's annual peak load as most recently measured at the substation or exceeds the annual minimum load as most recently measured. Monitoring and control equipment must be consistent with the written and published requirements and must be clearly identified by the utility. It could be assumed then that if the 15% trigger is met in a specific area, NorthWestern or MDU could require certain additional screening and inverter technology that allows for monitoring and control.

Throughout the rulemaking discussion before the PSC in 2010, utilities raised concerns about certain requirements being inflexible. Ultimately, the PSC approved rules that require interconnection equipment to be evaluated by a nationally recognized testing laboratory in accordance with the following standards:

- IEEE 1547-2003 (Including IEEE 1547.1-2005 testing protocols); and
- UL 1741 Inverters, Converters, and Controllers for Use in Independent Power Systems.

IEEE 1547 addresses maintenance, operation, performance, safety, and testing. The standard addresses universal requirements for interconnection and potential impacts to distribution systems. Power quality and requirements for design, production, installation evaluation, commissioning, and periodic testing are also addressed in the rules.

During the 2010 discussion, both NorthWestern and MDU stressed that the utilities wanted to be able to apply more stringent requirements than simply following the IEEE 1547 standard. With a few exceptions, the interconnection rules adopted by the PSC do not authorize a utility to impose additional requirements on a customer-generator, unless mutually agreed upon. The rules also include a dispute resolution process for interconnections. To-date, there have been no disputes over the rules as they potentially apply to net-metered facilities, according to the PSC.

While the rules also establish a solid process for interconnection that potentially applies to both NorthWestern and MDU and applies to net-metered customers, neither utility is complying with the rules in terms of net metering. It is unclear, however, whether there is concern from the net-metered community about the proper application of the interconnection rules. Technical aspects are currently included in interconnection agreements for Montana utilities, but net metering applications for NorthWestern are handled separately from interconnection requests. Requirements that standard forms, fees, and certain other paperwork aspects of the rule – as applied to net metering – are not fully addressed by Montana's regulated utilities. The PSC has contacted NorthWestern Energy, and the utility has indicated it will take steps to comply with the Montana rule in the future.

The PSC, to date, has been asked to neither enforce nor has it enforced the interconnection rules as they apply to net metering in Montana. Because there have been no disputes brought before the commission related to net metering, it is assumed that handling of net-metered facility applications for interconnection is meeting the current needs of customer-generators and utilities. However, it could be noted that the interconnection rules contemplate a number of safeguards to address more robust net-metering activity in the state.

As questions were raised about the interconnection rules, the PSC also discovered that the final, published rule did not reflect changes made by the PSC in 2010. For example, from 2010 until August 2015, the published rule established a 10 kW threshold for level 1 review instead of a 50 kW threshold – mirroring Montana's net metering statutes. The administrative rule was corrected to 50 kW on August 20.

NorthWestern Energy currently spells out guidelines for net metering in a net-metering request form. Montana-Dakota Utilities, through a Public Service Commission tariff, also requires customer-generators to sign an interconnection agreement. NorthWestern Energy requires any solar net metered system interconnect to its system with a static inverter that complies with: IEEE standard 929, "Recommended Practice for Utility Interface of Photovoltaic (PV) Systems; and UL Subject 1741, "Standard for Static Inverters and Charge Controllers for Use in Photovoltaic Power Systems".

In NorthWestern Energy's published interconnection requirement, net-metered systems are required to meet all "applicable safety, power quality, and interconnection requires established by the National Electric Code, the National Electric Safety Code, IEEE, and accredited testing laboratories."[8] A customer-generator is also prohibited from altering the factory set points for the owner's inverter without notifying NorthWestern Energy in writing. Systems must be capable of being manually isolated from NorthWestern's system with an external, visible load break, located between the generator and NorthWestern's system. A disconnect switch must be within 10 feet of the customer's electric meter and also must be marked "Generator Disconnect Switch". NorthWestern also has the right to lock the switch open whenever necessary to maintain safe electrical operating conditions.

Montana-Dakota Utilities Co. has similar interconnection requirements. MDU also may require customer-generators to interrupt or reduce deliveries of available energy, if the company determines that an interruption is necessary, according to the utility's net metering interconnection form. MDU also maintains its ability to disconnect a net metered system if "the

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[8] "Interconnection Standards for Customer-Owned, Net Metered, Grid-Connected Electrical Generating Facilities of 50 kW or Less Peak Generating Capacity," NorthWestern Energy, November 2010.

customer's generation, or its operation, may endanger the integrity of the company's electric system."[9]

Rural electric cooperatives in Montana have adopted a uniform net metering policy with interconnection guidelines; although individual cooperatives may choose to modify this policy. As an example, the Sun River Electric Cooperative's interconnection application requires a certified professional engineer to review and approve a customer-generator's facility. The review includes "safety considerations relevant to both parties, the feasibility of such interconnection and benefits of such, for both the member and the cooperative." The agreement also requires indemnification and liability insurance.[10]

Model Rules and Procedures

In 2005, the Federal Energy Regulatory Commission (FERC) adopted Small Generator Interconnection Procedures and a model interconnection agreement. The procedures are for generating facilities 20 MW or less and govern FERC-jurisdictional interconnections. The procedures also are recommended as "a model that state regulators may use as a starting point for developing their own interconnection procedures and agreement". In 2013 FERC revised and updated the rule to ensure that the rates, terms, and conditions of interconnection service for small systems were "just and reasonable and not unduly discriminatory or preferential."[11]

The FERC model, while focused on wholesale generation as opposed to residential or retail, establishes three levels of review for interconnection: level 1, inverter-based facilities with a capacity less than 10 kW; level 2, systems that are less than 5 MW; and level 3, a "study process" for other systems. The standards establish different levels of review for the systems and establish certain interconnection study requirements for generators that cause aggregate generation capacity to exceed 15% of annual peak load on a line section of a radial distribution circuit. Montana's interconnection rules are quite similar, although certain aspects at various levels conform with Montana regulations.

The 2013 FERC reforms addressed concerns in level 2 and level 3 interconnections. The level 2 option for a fast-track review was increased from 2 MW to 5 MW. The study process for level 3 was also improved. The final rule didn't modify the 15% screen but modified the optional supplemental review process following failure of the screen to include different, supplemental review processes. "The commission reasoned that if generation penetration levels are causing projects to fail the 15% screen, the screen should be re-examined to determine if revisions could be made to allow projects to continue to participate in the less costly and time-consuming fast track process while maintaining the safety and reliability of the transmission provider's system."[12]

The reforms also included a requirement that transmission providers offer customer generators the option to request a pre-application report that contains readily available information about system conditions at a point of interconnection to help that customer select the best site for a facility. A $300 fixed fee accompanies the pre-application report, and the transmission provider is tasked with completing it within 20 business days.

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[9] Net Metering Service Rate 92, Montana-Dakota Utilities Co., D2007.7.79, June 2008.

[10] Sun River Electric Cooperative Interconnection Application and Sun River Electric Cooperative, Inc., Policy #314 Customer Owned Generation, December 2008.

[11] Federal Energy Regulatory Commission, "Small Generator Interconnection Agreements and Procedures", RM 13-2-000; Order No. 792, November 2013, page 7.

[12] Ibid., page 16.

The concept behind the model rules categorizes interconnection from least complex to most complex. By establishing different levels, the fees, study, and processing time can be minimized for certain groups while still maintaining safety and reliability requirements.

The Interstate Renewable Energy Council also offers model interconnection procedures and net metering rules for use by state utility commissions and other stakeholders. The model procedures are broken down into four levels or paths. The paths include: level 1, inverter-based facilities with a capacity of 25 KW or less; level 2, facilities with a capacity up to 5 MW; level 3, facilities that do not export power to a utility with a capacity of 10 MW or less; and level 4, facilities that don't qualify for the other three processes.

The model standards include a pre-application process for a customer-generator and for a utility. In the preliminary process, the utility provides, for example, the number of protective devices and the number of voltage regulating devices between the proposed site and the substation/area. "A structured pre-application report can reduce unnecessary interconnection applications by providing information about system conditions at a proposed point of interconnection. Without this information, developers may submit multiple applications to find out which of many potential project locations have the lowest costs, resulting in a high volume of applications."[13]

The interconnection review for a level 1 connection includes an indemnification clause, but does not include liability insurance requirements and places limits on liability. For interconnection, a customer-generator also must show that a generating facility aggregated with all other generation is only capable of exporting energy on a line section that does not exceed 15% of the line section's annual peak load as most recently measured at the substation or calculated for the line section.

As discussed previously, 15% of peak load was established in the FERC procedures as a conservative estimate of minimum load. If a generating facility is single-phase and is to be interconnected on a transformer center tap neutral of a 240-volt service, a customer-generator also must demonstrate that it will not create an imbalance between the two sides of the 240-volt service of more than 20% of nameplate rating of the service transformer. The same parameters are incorporated into the Montana interconnection rules.

Level 2 requirements are similar to level 1 but establish generating capacity limits that vary according to the voltage of the line at a proposed point of interconnection. The model rules for level 1and 2 require that a facility be inspected and approved by the appropriate local electrical wiring inspector with jurisdiction, and a customer-generator then provide documentation of the approval to the appropriate utility. In general the model rules also allow a utility to inspect a facility to insure that it complies with technical requirements. With appropriate testing at each facility, a utility should have some assurance that a facility will safely disconnect from the utility's system in the event of an outage.

The Bonneville Power Administration's load-following customers also must meet specific interconnection requirements. Resources with a 200 kW nameplate capacity or more are subject to FERC's interconnection procedures for small generators as part of BPA's open access transmission tariff. Compliance with the National Environmental Policy Act is also required before an interconnection agreement is complete. BPA requires a host utility to submit

[13] "Model Interconnection Procedures", Interstate Renewable Energy Council, 2013 Edition, page 3.

an interconnection request and a $2,500 application fee. A $5,000 deposit for each of up to three technical studies also is required in some instances. If a resource is greater than 1 MW in nameplate capacity, the utility also must purchase additional BPA products including resource support services to account for the costs of integration.[14]

Advancing Interconnection Standards

The IEEE and UL standards previously discussed are focused largely on matters of safety and reliability. However, there are additional technical issues related to net-metered facilities. For example, the standards often implemented by utilities typically require a net-metering facility's inverters disconnect from the grid at any sign of instability. While promoting safety, the standards can undermine the ability of photovoltaic power, for example, to contribute to grid stability. Smart or advanced inverters are considered by many in the industry to be the key to addressing this issue. An inverter changes direct current (DC) to alternating current (AC). This is a critical component for a net metering facility. Renewable energy facilities rely on inverters to connect to the grid. "With smarter inverters capable of contributing to grid stability, utilities stand to gain the monitoring and control they need to successfully integrate PV power on a large-scale distributed basis."[15]

A smart inverter is capable of bidirectional communication. Advanced or smart inverters have the ability to:

- Maintain a net-metered facilities connection to the grid, rather than disconnecting during minor voltage disturbances;
- Produce power and generate or consume reactive power to assist during voltage swings; and
- Facilitate real-time communication, allowing utilities or customer-generators to remotely access systems to meet the needs of the grid.

In 2014, the IEEE amended its standards to allow for advanced capabilities for voltage regulation support and voltage and frequency ride-through. The IEEE is continuing to work on updates to its standards to better address advanced inverter capabilities. The IEEE process is expected to be completed before 2018.[16]

There are also a number of studies ongoing in the country, led primarily by the U.S. Department of Energy, as well as within various utilities and utility and solar organizations to examine the use of advanced metering. "As the penetration level increases for PV generation, and as more sophisticated rules for interconnection emerge, it has become clear that harnessing these inverter capabilities will be key to the successful implementation of large-scale PV generation in distribution systems."[17]

The Western Electric Industry Leaders (WEIL) organization, a group of utility executive leaders, has endorsed the use of advanced inverters and has urged their installation on all new PV. "We feel that this change is well worth the small cost to the consumers who choose to use solar

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[14] Net Metered Facilities Fact Sheet, Bonneville Power Administration, February 2013.
[15] "Laying the Foundation for the Grid-Tied Smart Inverter of the Future," Advanced Energy, 2011.
[16] Thomas Basso, IEEE 1547 and 2030 Standards for Distributed Energy Resources Interconnection and Interoperability with the Electricity Grid, National Renewable Energy Laboratory, U.S. Department of Energy, December 2014.
[17] Colin Schauder, "Advanced Inverter Technology for High Penetration Levels of PV Generation in Distribution Systems," National Renewable Energy Laboratory, U.S. Department of Energy, March 2014, page 5.

installations. For a solar installation costing $12,000, these new smart inverters will only cost about $150 more than the current inverters, approximately 1% of the overall cost."[18]

While the use of advanced meters appears to be a potential benefit to the owners of distribution systems, the technology also raises questions for customer-generators to consider. Customer-generators with smart inverters ultimately provide ancillary services to utilities, can incur additional operating costs, and may lose private power generation. There are also policy considerations related to requirements for advanced inverters, "including compensation to generators for grid services provided, requirements for availability of grid services by inverter-based systems, system disconnect and operation standards, and inverter ownership structures."

If net-metered facilities are required to use smart inverters to contribute to voltage control on the distribution circuit, there are questions as to whether the customer-generator should be paid for their service to the grid. If smart inverters also require a customer generator to curtail generation then options also may need to be developed to compensate customer generators for lost revenue. Advanced meters also are not the only answer to integrating a growing number of net-metered facilities to the grid. "Other mechanisms to support increasing levels of distributed generation, such as grid upgrades and the adoption of energy storage will have to be considered as well. Nevertheless, advanced inverters represent an option that is available, operational, and potentially cost-effective in the near term."[19]

<u>Advanced Inverters in Other States</u>

Some utilities and utility commissions are recommending or requiring the use of smart inverters. The requirements, however, are triggered primarily by a certain saturation of net-metered facilities on a system. As previously discussed concerning interconnections, penetrations of 15% of customer peak load on a distribution circuit are often used as a trigger for detailed interconnection studies or additional requirements. In California and Hawaii, generators are divided on the basis of whether their capacity could exceed 100% of minimum customer load on a distribution feeder. "A utility will have broad discretion in these states to assess potential impacts to safety, reliability, and power quality both above and below this this threshold, but below the threshold, it will have less time to assess potential impacts."

Montana's net metering policy does not include any capacity or saturation limits related to interconnection, however, the interconnection rules adopted by the PSC clearly contemplate some saturation at least in specific distribution areas. NorthWestern Energy in 2013 estimated its peak load at about 1,200 MW.[20] Net metered facilities represent about 5.6 MW on the NorthWestern system, or slightly less than about .005%. It is unknown at this time if net-metered facilities are concentrated on certain distribution circuits in Montana and worthy of a more in-depth interconnection review. With such minimal saturation, however, it is unlikely.

On the island of Oahu, photovoltaic generation accounts for about 250 MW on a 1,200 MW grid. Hawaiian Electric Companies (HECO) owns the utilities on the islands of Oahu, Maui, and Hawaii. "As of the end of 2014, over 51,000 systems have been installed, almost 11,000 in 2014 alone, representing 390 total MW of capacity and 12% of residential customers."[21] On some of

[18] Western Electric Industry Leaders, letter to governors, commissioners, and legislators, August 2013.

[19] "Advanced Inverter Functions to Support High Levels of Distributed Solar," National Renewable Energy Laboratory, U.S. Department of Energy, November 2014.

[20] NorthWestern Energy, 2013 Annual Report. http://www.northwesternenergy.com/docs/default-source/documents/investor/AnnualReport2013.pdf?sfvrsn=2.

[21] Hawaiian Electric Companies' Motion For Approval of NEM Program Modification and Establishment of Transitional Distributed Generation Program Tariff, Docket No. 2014-0192, January 2015.

those circuits the amount of solar being generated was exceeding the energy used by customers on the circuit, raising utility concerns about voltage disruptions and grid stability. Because of the concerns and because of plans to increase solar, HECO joined with the National Renewable Energy Laboratory and SolarCity, an energy services provider, to assist the utility in testing advanced inverters to resolve the issue. The study is funded through the U.S. Department of Energy's SunShot Initiative.

In June 2015 HECO established a qualified equipment list that will supplant current standards and requirements for net-metered facilities. The new equipment requirements related to inverters were developed based on the study conducted in 2014. The requirements establish new transient over-voltage (TrOV) and frequency and voltage ride-through requirements for inverter-based distributed generation and energy storage. The requirements will allow HECO to integrate more solar onto its system.[22] HECO plans to increase circuit thresholds from their current levels of 120% of daytime minimum load to 250%, doubling the hosting capacity of circuits to integrate rooftop solar systems. "Inverter testing carried out at NREL's Energy Systems Integration Facility revealed that most inverter technology possesses the capability of safely managing distributed energy on to the grid, finding that a typical inverter could act as a proxy 'junior grid', thus overcoming the technical barriers that have limited DG penetration in Hawaii and elsewhere in the U.S."[23]

The study is ongoing and will also examine the use of advanced inverters to "support distribution voltage regulation, to mitigate utility concerns related to bi-directional power flow, and to determine the effectiveness of multiple inverter islanding during faults."

California was the first state to adopt advanced inverter standards. The requirement was triggered largely by assumed technical challenges to incorporating up to 12,000 MW of additional distributed generation to California's grid by 2020. The California Energy Commission forecasts that Pacific Gas and Electric peak electricity demand will reach between 24,782 to 27,721 MW by 2024. Installed PV system capacities are expected to range from 2,180 MW to 2,800 MW by 2024. PV penetration could be roughly 9% to 10% of peak demand. For San Diego Gas and Electric, the commission predicts peak electricity demand reaching between 4,998 to 5,790 MW by 2024 and installed PV capacities ranging from 683 MW to 819 MW by 2024. PV penetration levels for the utility could be up to 14%.[24]

A Smart Inverter Working Group was formed in California and noted that distributed generation was largely "tolerated" by utilities and required to trip-off during any disturbance. "This approach has recently led to grid stability problems in other countries with high penetrations of distributed energy resources."[25] The working group found that distributed generation could be a powerful tool for managing reliability and power quality with advanced inverter technologies.

In 2014 the California Public Utilities Commission determined that the use of advanced inverters was mandatory with the deployment of distributed energy resources beginning in 2016. The ruling applies to California's three investor-owned utilities. Under the ruling, the three IOUs must

[22] http://www.hawaiianelectric.com/vcmcontent/StaticFiles/pdf/TrOVandFVRT_Public_June2015.pdf

[23] Ian Clover, "SolarCity's Hawaiian study reveals grid regulation potential of inverters," *PV Magazine,* February, 2015, http://www.pv-magazine.com/news/details/beitrag/solarcitys-hawaiian-study-reveals-grid-regulation-potential-of-inverters_100018207/#axzz3f7hQFhvO.

[24] California Energy Demand 2014-2024 Revised Forecast, Volume 2: Electricity Demand by Utility Planning Area, http://www.energy.ca.gov/2013publications/CEC-200-2013-004/CEC-200-2013-004-SD-V2-REV.pdf.

[25] Recommendations for Updating the Technical Requirements for Inverters in Distributed Energy Resources, Smart Inverter Working Group Recommendations, January 2014.

install advanced inverters the later of December 31, 2015, or 12 months after the date the UL approves applicable standards.[26] The PUC determined that advanced meters would improve reliability and efficiency. The first phase of the smart inverter functionality approved in California requires: voltage and frequency ride through; real and reactive power control; return to service behaviors/ramp rate control. Phase 2 is to include bi-directional communication standards for inverters.[27] "The new inverter standards mark a big change for equipment that utilities have viewed largely as a nuisance."[28]

<u>Interconnection Questions for ETIC consideration:</u>

- Do the requirements of 69-8-604, MCA adequately address interconnection procedures for the current level of net metering on NorthWestern's system?

- Do the administrative rules adopted by the PSC adequately address interconnection requirements in Montana? Are the rules being adequately enforced by the PSC?

- Do the interconnection rules apply to MDU, and if not, should the rules apply?

- If net metering increases on NorthWestern's system, should the law or rules be modified?

- If yes, how should they be changed? Request or require a utility:
    - Revisit rules for paths or levels for interconnection?
    - Provide a pre-application process?
    - Set different timelines for processing interconnection requests?
    - Require customer-generators provide certain levels of liability insurance?
    - Establish legal indemnification requirements?
    - Fees for various aspects of interconnection?
    - Set specific technical requirements for disconnect switches, separate transformers, synchronizing devices?

- If changes are needed, should the law establish:
    - New capacity limits for advanced interconnection review?
    - Appropriate use of smart inverters?
    - If smart inverters are needed, additional regulatory considerations?

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[26] http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M143/K827/143827879.PDF

[27] California Energy Commission and California Public Utilities Commission, Recommendations for Utility Communications with Distributed Energy Resources Systems with Smart Inverters; Smart Inverter Work Group Phase 2, February 2015.

[28] Peter Fairley, How Rooftop Solar Can Stabilize the Grid Following Germany's lead, California gives advanced inverters a bigger role in the grid, *IEEE Spectrum*, January 2015.