BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

Docket No. UM 2032

In the matter of

PUBLIC UTILITY COMMISSION OF OREGON,

Investigation into the Treatment of Network Upgrade Costs for Qualifying Facilities

RESPONSE TESTIMONY OF BRIAN S. RAHMAN

October 30, 2020

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Brian S. Rahman. I am the Executive Director of Engineering at ZGlobal Inc. My business address is 604 Sutter Street, Suite 250, Folsom, California 95630.

Q. Please describe your background and experience.

A. I am an electric power professional with a 30-year career which has focused on extensively on interconnection and transmission, including planning, design, power flow analysis, transmission system capacity analysis, power scheduling and trading, and extensive related policy, market, regulatory, and technical matters. I have held a wide variety of roles during that time, as a utility professional, employee of California Independent System Operator, and as an employee of one of the leading engineering and technical firms in California, ZGlobal, where my work has ranged from technical engineering studies to development support, to managing and working with a group of leading engineers and policy experts related to interconnection and transmission, many of which are former CAISO and/or utility interconnection and transmission professionals, working for a broad range of clients on projects of all sizes, in numerous states and utility service areas and transmission and distribution systems. I have also worked as an expert witness on multiple occasions (see below), including on behalf of the CAISO in a legal dispute. My full resume is attached as NewSun/101. I have a Bachelor of Science Degree in Electrical Engineering from Washington State University and am a Registered Professional Engineer in the State of California, PE License number 14914. I have been with ZGlobal since October 2006. Prior to this was employed by the California Independent System Operator for 9 years where I held various staff and management positions including Manager of Market Operations and Director of the Project Management Office. I began my career at Pacific Gas and Electric in 1991 where I worked as a staff level engineer in the bulk transmission operations group, hydro-electric generation, and distribution planning.

Over the past 15 years with ZGlobal I have worked on hundreds of large and small generator interconnections across the Western United States including projects in Oregon, Washington, Montana, Nevada, Arizona, California, Utah, and New Mexico. These projects have ranged in size from 2 MW to 3,200 MW and include an array of technologies and system impacts. Additionally, I have worked on many transmission service requests (TSRs), both Network and Energy Resources, including those within Imperial Irrigation District, Nevada Energy, LA Department of Water and Power, Bonneville Power Administration, Public Service Company of New Mexico.

Q. On whose behalf are you appearing in this proceeding?

A. I am testifying on behalf of NewSun Energy LLC.

Q. Have you previously provided testimony in any state or federal regulatory dockets or court cases?

A. During the past 4 years I have participated as an expert witness in the following proceedings: (1)*Tesoro Refining and Marketing Company LLS v. Pacific Gas & Electric Company* (Case No. 14 CIV 00930 (JCS)) in the United States District Court, Northern District of California; (2) *Imperial Irrigation District v. California Independent System Operator Corporation* (Case No. 3:15-cv-01576-AJB-AGS) in the United States District Court, Southern District of California;(3) *McKinley Hove Foundation v. West Hills* (No: KC069072) in the Superior Court of California, County of Los Angeles, Pomona

Courthouse South; and, (4) *California Solar Ranch v. Area Energy* (JAMS ref. No 1100088728), an arbitration proceeding. Prior to the past 4 years, I represented the CAISO as an expert on matters related to system voltages and reliability issues in a case presided over by an Administrative Law Judge[1].

Additionally, during my time at the CAISO, I provided written testimony to the Federal Energy Regulatory Commission (FERC) related to market rules and functionality. I provided written testimony to FERC on 3 occasions which included comments related to the re-design of the CAISO markets under the Market Re-Design and Technology Upgrade (MRTU) project[2], development of Business Practice Manuals for MRTU[3], and Long-Term transmission rights in organized markets[4].

Q. Please summarize your testimony.

A. My testimony responds to the Joint Utilities' Direct Testimony and addresses the two issues raised in this docket:

(1) Who should be required to pay for Network Upgrades necessary to interconnect the QF to the host utility?

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[1] "Arbitration Findings and Award in Cities of Anaheim et al. v. the ISO & Southern California Edison regarding "Allocation of Transmission Cost", Rahman, B., Testimony, Docket No. EL03-54-000, August 27, 2003.

[2] "California Independent System Operator Corporation Electric Tariff Filing to Reflect Market Redesign and Technology Upgrade", Docket No. ER06, declaration and testimony of Brian Rahman, Program Director of CAISO Market Re-design and Technology Upgrade (MRTU), Submitted to FERC on February 9, 2006.

[3] "Post-Technical Conference Response of the California Independent System Operator Corporation on Business Practice Manual Issues", Brian Rahman, Program Director of CAISO Market Re-design and Technology Upgrade (MRTU), submitted to FERC in March 2007, Docket # ER06-615-012 and ER 07-1257-000

[4] "Long-Term Firm Transmission Rights in Organized Electricity Markets" proposal by Brian Rahman, Program Director of CAISO Market Re-design and Technology Upgrade (MRTU), Submitted to FERC Docket Nos. RM06-8-000 and AD05-7-000, March 13, 2007

(2) Should on-system QFs be required to interconnect to the host utility with Network Resource Interconnection (NRIS) or should QFs have the option to interconnect with Energy Resource Interconnection Service (ERIS) or an interconnection service similar to ERIS?

Based on my experience and prior work throughout the WECC area on many generator interconnections with various host utilities, I contend that:

1. Host utilities should ultimately pay for the network upgrades necessary to interconnect the QF. That is, QFs should be treated the same as any other generator type, with refunds of any network upgrade costs they might pay up-front. For which this is the overwhelmingly prevailing, if not universal, practice outside of Oregon QFs.

2. The interconnection process of the host utility should provide the QF with the cost for both NRIS and ERIS and allow the QF the option to select the service that best meets the QF business objectives.

My testimony does not respond to the parts of the Joint Utilities' Direct Testimony where they characterize Oregon Public Utility Commission (PUC) and Federal Energy Regulatory Commission (FERC) laws and policies.

II. ISSUE 1: COST RESPONSIBILITY FOR NETWORK UPGRADES

Q. This docket is about Network Upgrades. Can you please explain what Network Upgrades are and how they are identified?

A. When a prospective generator proposes to be interconnected to the grid, there is an interconnection study process which the applicable transmission owner goes through in order to evaluate the ability of the grid to interconnect the facility to the grid, including the capacity of the system to support the generator, impacts the generators would have, and what new system features, safety and reliability measures, generator metering and communication requirements, as well as downstream upgrades might be necessary, to meet minimum applicable reliability and other standards for the grid should the generator be built. These studies generally happen through a sequence of three primary studies: a feasibility study (sometimes optional), a system impact study ("SIS"), and a facilities study ("FAS"), which sequentially look in greater detail at the impacts of the facility to the system.

- Network Upgrades are one of the two primary types of upgrades identified to mitigate, where applicable, certain impacts, and achieve the required standards associated with the interconnection of a new proposed generation facility. The upgrades (and costs) to successfully, and in compliance with applicable regulatory standards are generally allocated into two groups as follows:

  1) "***Interconnection Facilities***" are those facilities (and costs) strictly associated with interconnecting the project-specific generator itself reliably *to* the existing host transmission system. The associated facilities (and costs) are also called "Direct Assign" facilities (and costs), meaning that they are only needed due to the physical interconnection of the generator and the generator is the sole reason these facilities are needed. Direct Assignment facilities (and costs) for interconnection, for example, include items such as the interconnection substation elements needed to terminate the generator's tieline and looping in and out of the existing utility transmission line, or to connect the generation facility's customer-owned substation to the utility-owned grid. Direct Assigned Interconnection Facilities may also commonly include the addition of protection devices (i.e. protective relays) at substation remote from the point of interconnection that are solely needed for coordinating line protection with the new interconnection substation. Direct Assignment facilities cost are entirely the responsibility of the generator developer as they do not provide benefits to others. Direct Assign interconnection facilities *do not include* "downstream" impacts to the system which must be upgraded to support the generator, but which also benefit the grid more broadly than the specific project, which are generally called network upgrades, as described further below.

2) *"Network Upgrades"* are facilities necessary to interconnect a generator associated with system upgrades *beyond the point of interconnection* (i.e. beyond the interconnection substation) both locally and regionally, required to address reliability impacts as well as deliverability of the generation to system demand.

Q. Are there different types of Network Upgrades? If so, please explain further about the types and purpose of these?

A. In my experience with the various utility interconnection processes there are two types of upgrades that may be required associated with the interconnection study beyond the project-specific, direct assignment Interconnection Facilities needed for the basic interconnection to the electric grid. These are either Reliability Upgrades (RU) or Network Upgrades (NU).

Reliability Upgrades are those upgrades needed to meet basic NERC/WECC reliability standards. They are most often associated with elements such as short circuit ratings of existing substation equipment such as breakers and switches, and typically very local to the interconnection site location. Other Reliability Upgrades may include expansion of substation buses and installation of special protection schemes. In general, RU are required to ensure the bulk electric grid is in compliance with North American Electric Reliability Corporation (NERC) reliability standards and WECC reliability criteria.

Network Upgrades are typically needed to support the delivery of energy from generation resources to some loads, i.e. loads that may be remote from the generator, or export points at the boundary with neighboring transmission owners. NU often include upgrades to limiting equipment within substations such as under rated equipment or conductors. At times, with large additions of generation, network upgrades may include the need for upgraded or new transmission lines and associated facilities. Network Upgrades can be further categorized into local and area (or regional) network upgrades.

Local Area Upgrades are those upgrades in close proximity to the Point of Interconnection. For example, consider a single transmission line that is bisected so that an Interconnection Facility can be added and during the system impact study, the host utility finds that during an outage of one of the line segments results in an emergency overload of the other while the generator is operating. Under this scenario, the host utility would identify a local network upgrade which could include a special protection scheme to remove the generator in the event of the line outage or a physical capacity increase. While this specific upgrade might appear to be solely associated with the interconnecting generator, it allows for an increased utilization of existing transmission system capacity, not only by the interconnecting generator but to the host utility as well as other “merchant” generation in the area. In other words, it provides a benefit to system capacity, especially within the local area for both merchant generation as well as the host utility.

Area, or regional, network upgrades are most often associated with upgrades to bulk transmission lines and facilities needed for "deliverability" of generation to the aggregate of load on the host utility system. These types of network "deliverability" upgrades provide a broad system wide benefit. For example, under typical study conditions, were the system planner considers the system impacts under stressed system conditions such as 1 in 10 year peak load and minimum load conditions both with all existing generation in operation ignoring economic dispatch, they are likely to find that additional system capacity is needed to avoid line overloads while serving native load. The mitigation of these types of overloads are often very expensive, large scale, upgrades of existing transmission lines or the addition of new transmission lines, both of which result in system wide benefit to not only generators but to the host utility.

Although network upgrades can be categorized as I have done above which is consistent with CAISO approach, many transmission owners within the WECC, simply group Reliability, Local and Area Upgrades all together under the single Network Upgrade category. In general, across the WECC, Network Upgrades are treated separately from Interconnection Facilities because Network Upgrades are refunded.

Q. The Joint Utilities describe two different types of upgrades as well. Can you explain whether RU and NU as you understand them are consistent with the two types of upgrades described by the Joint Utilities?

A. Sure. First, the Joint Utilities describe Network Upgrades identified in an Energy Resource Interconnection Service (ERIS) study that are primarily needed to safely and reliably physically interconnect the generating resource to the utility's transmission system.[5] Under an ERIS the Joint Utilities are describing Reliability Upgrades needed to meet basic reliability criteria as I describe above and do not include local or area deliverability network upgrades. This would be consistent with my understanding of an ERIS and the types of "network upgrades" that an ERIS interconnection study would identify. An ERIS, by definition, allows for the use of existing firm capacity, which would not include any local or area capacity increases.

Second, the Joint Utilities describe Network Upgrades beyond those identified in an ERIS that are needed to ensure the aggregate of generation in the area where the generator proposes to interconnect can be reliably delivered to the aggregate of load on the transmission provider's system during peak load conditions.[6] The utilities also describe these as "deliverability-driven Network Upgrades, or [Network Resource] Network Upgrades." The Joint Utilities are describing the Local and Area Network Upgrades I discuss above. This is consistent with my understanding. These types of Network Upgrades, local or area, are identified in the study process to enable deliverability of generation to the aggregate of system load, even if this system load is far removed from the generator and under most often under stressed system conditions.

Q. What is your understanding of how transmission providers generally evaluate and classify upgrades?

A. In my experience, working within the WECC on transmission level interconnections, the same or very similar rules and methodologies apply with respect to evaluation of the electric system and general classification of upgrades. In some situations, the local utility

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[5] Joint Utilities/100, Vail-Bremer-Foster-Larson-Ellsworth/8.
[6] Id.

may apply slightly different criteria in the classification of a specific upgrade as either Reliability or Network. For example, one utility may include a special protection scheme as a reliability upgrade because it addresses a specific reliability violation such as a contingency overload. But another, may view this same upgrade as being more akin to a network upgrade because it actually allows for a higher utilization of existing transmission capacity. However, with the exception of how QF's are treated within Oregon, the utility is always the ultimate beneficiary of the increased capacity associated with network or reliability upgrades and either funds these upgrades directly or, if initially funded in some cases by the interconnection customer, provides a refund to the generator who finances or secures the funding for upgrades after the energization of the associated facilities.

Q. You say Oregon is the exception. Have you experienced any other interconnection processes that treat QFs differently?

A. Given how the balance of transmission owners within the WECC treat the cost responsibility for Network Upgrades, it is befuddling why Oregon would implement a separate tariff and treat state jurisdictional interconnections differently than others. Network Upgrades to the transmission system benefit all system users, not just the QF in question, and increase the value of the transmission system "asset". Putting this cost burden on a specific QF, with no ability to recover costs, puts the QF at a significant economic disadvantage and provides the utility with added system value at little or no cost.

Q. Who should be required to pay for Network Upgrades necessary to interconnect the QF to the host utility?

A. I believe, considering the treatment of Network Upgrades by all other transmission owners and planning entities I have worked with on interconnections, network upgrades should ultimately be payed for by the transmission owner. While there are variations in whether the interconnection customer might pay for certain upgrades up front versus these be initially paid for by the utility directly, and certain variations in the repayment schemes that repay interconnection customers who do directly fund certain upgrades, the transmission owner and their ability to reliably serve interconnected demand is really the beneficiary of the network upgrade. As discussed above, Network Upgrades, specifically those associated with increasing system capacities have system wide benefits by increasing overall system capacity and in general the robustness of the interconnected system. For example, a relatively small upgrade to a transmission line, even in remote section of the grid, will likely improve the voltage profile of the remote area which in turn will improve the voltage profile of less remote segments of the interconnected grid, improving overall performance, resulting in lower system losses, and increased transfer capability to serve customer demand. This is certainly a system wide benefit to the transmission owner. There are also benefits in terms of improved reliability management, including for outages, due to additional flexibility added to segment and disconnect parts of the system, as well, for example, larger line sizes, which can both be used to move more power as well as allow the system to operate farther from its peak capacity and mitigate associated stresses and failure points under peak system conditions or unplanned outages.

Q. Can you provide some examples of how other transmission providers and host utilities treat Network Upgrades?

A. There are many examples of host utilities and transmission owners that include provision in their interconnection processes that provide a refund to the generator developer for the cost of Network Upgrades. In some cases, this is a refund of up-front funds provided by the QF while in some cases, where no direct up-front funding is required from the interconnection customer, but rather solely a letter of credits ("LOC"), it is simply the termination of requirement to maintained the posted a Letter of Credit (which would have only been drawn on in the event some upgrade costs have been incurred but the project development has stopped). The following describes how a few of the other host utilities handle the cost/refundability of required network upgrades.

Interconnection Authority	Network Upgrade Security Methodology	Refund Methodology
California ISO	Generator posts Cash or LOC at conclusion of SIS (Phase 1) and FAS (Phase 2). Balance of funding included in LGIA Milestones.	Refunded over 5 year period from date upgrade reaches COD. Applies to Reliability and Local Area Network Upgrades Only
PG&E	Generator posts Cash or LOC at conclusion of SIS (Phase 1) and FAS (Phase 2). Balance of funding included in LGIA Milestones.	Refunded over 5 year period from date upgrade reaches COD. Applies to Reliability and Local Area Network Upgrades Only
SCE	Generator posts Cash or LOC at conclusion of SIS (Phase 1) and FAS (Phase 2). Balance of funding included in LGIA Milestones.	Refunded over 5 year period from date upgrade reaches COD. Applies to Reliability and Local Area Network Upgrades Only
SDG&E	Generator posts Cash or LOC at conclusion of SIS (Phase 1) and FAS (Phase 2). Balance of funding included in LGIA Milestones.	Refunded 100% upon upgrade reaching COD. Applies to Reliability and Local Area Network Upgrades Only
NVEnergy	Generator posts LOC as backstop in event project fails but work has been done on network upgrade.	LOC terminated once network upgrades complete
IID	Generator funds network upgrade	Generator receives dollar for dollar transmission service credits. If not able to utilize, they can sell to others in need

Q. **Thank you. What is the risk of not refunding the costs of Network Upgrades and requiring the QF to bear that cost?**

A. Regardless of the host utility, it is the host utility that pays for the upgrade and ultimately passes these costs to the customer via a transmission revenue requirement. Alternatively, the QF would need a higher cost for the energy produced to absorb the cost of the network upgrade. This in turn will ultimately be an incremental cost also passed to the customer. Comparing the Oregon approach to what others do, Oregon substantially disadvantages the QF and its approach appears to be discriminatory.

III. ISSUE 2: INTERCRONNECTION SERVICE AVAILABLE TO QFS

Q. Please define ERIS and NRIS.

A. Energy Resource Interconnection Service (ERIS) is defined as "an Interconnection Service that allows the Interconnection Customer to connect its Generating Facility to the Transmission Providers Transmission System to be eligible to deliver the Generating Facility's electric output using the existing firm or nonfarm capacity on the Transmission Providers Transmission System on an as available basis".

Network Resource Interconnection Service (NRIS) is defined as "an Interconnection Service that allows the Interconnection Customer to integrate its Large Generating Facility with the Transmission Provider's Transmission System (1) in a manner comparable to that in which the transmission Provider integrates its generating facilities to serve native load customers".

Q. When is each interconnection service type typically used?

A. ERIS is used by generators that can operate and deliver energy utilizing the existing system capacity on an as-available basis. The decision to go with ERIS as opposed to NRIS is generally a decision left to the generator based on many factors including: cost of the network upgrade, risk of curtailment, power purchase agreement provision, and ability for the generator in general to remain economically viable. In the case of renewable generation such as solar, ERIS is often found to be acceptable when economic dispatch is considered. Under a least cost economic dispatch, constrained by system capacities, solar will most often be the least cost during sunlight hours and be the primary user of system capacity. Gas plants and non-renewable resources will most often be needed in the early morning and evening hours when solar is not available. Consequently, from a practical perspective, considering economic dispatch, ERIS can be an acceptable arrangement for solar generation and avoid costly and possibly unnecessary network upgrades.

NRIS is used by generators that require dedicated firm system capacity to satisfy a power purchase agreement or otherwise require or desire firm capacity to avoid curtailments and financial deficiencies. In most cases the need to be "deliverable" via firm system capacity also comes with added benefit in terms of energy value. Without a corresponding increase in energy value corresponding with the "firm" capacity associated with a costly network upgrade, the generator may become un-economic and will certainly be disadvantaged in terms of energy price needed to remain an economically viable project. From my experience, working with generation interconnections across the WECC, NRIS is most often used by generation that may be exporting form the area they are interconnected with to a neighboring area and selling a firm or "deliverable" energy product, or they have a contract obligation imposed by the buyer that requires firm transmission service for deliveries within the host utility area. It is decidedly less common, unless perhaps a study that looks at ERIS *and* NRIS, as is sometimes requested by interconnection customers, shows no additional cost for the NRIS due to not requiring upgrades to achieve NRIS.

With either approach, it is most often the generator that must make the decision on what type of service best meets their business needs and objectives. From my experience, it is unusual for the host utility to force the choice upon the generator developer.

Q. What is your understanding of the host utility's responsibility?

A. The host utility is typically also the load serving entity with the ultimate responsibility of serving the end use customer, retail or others not operating at a wholesale level. With this responsibility, also comes the ability for the host utility to incorporate the costs of system upgrades, reliability or deliverability, into their Transmission Revenue Requirement, which is a common approach across the WECC, with the apparent exception of Oregon's QF treatment.

Q. What is the impact of shifting network upgrade costs to the generator?

A. First, shifting the network upgrade cost to the generator, puts an unnecessary financial burden on the generator, and will result in higher overall project costs for energy produced by the specific generator burdened with the additional cost, with commensurate implications for project economics and project viability. These costs are further amplified by the fact that interconnection costs—whether direct assign or network upgrades—are not eligible for tax credits, meaning their impact is effectively a multiple of the costs. So additional costs, especially if not needed for the delivery of the power to the utility, burden and might kill the project's viability. This is true in the case that such costs are small, proportionally, but even more in the case that unnecessary large costs are added. There is also an issue from the perspective of the developer being required to post such costs, especially when large, before a PPA is secured, in terms of the risk profile (or even impossibility) of posting them before a viable off-take agreement is secured. Oregon's approach is thus unnecessarily burdensome on the generator developer and ultimately would be harmful to a QF and discriminatory to a QF generator as compared to substantially identical generator (i.e. same size and technology) that would interconnect, and be allowed to sell power, as is common, as an ERIS.

Q. What is the risk of forcing QFs to interconnect with NRIS?

A. By forcing the QF into the Network Resource Interconnection Service (NRIS) bucket the host utility imposes an economic burden on the QF not imposed on other generation in a similar situation. This is especially true for intermittent renewable generation that is unlikely to fully utilize the upgrade. Moreover, with increased system capacity, the incentive for the utility to find the most economic dispatch is removed. For example, If QF generation is more efficient (less expensive) than an existing utility generation asset, then under a constrained transmission system the less expensive generation should be dispatched. However, if transmission capacity has been increased on the back of the QF, then there is reduced incentive for the host utility to perform economic dispatch and possibly curtail the more expensive utility asset.

NRIS, by definition, provides for the generator to be integrated within the transmission system similar to how the utility would integrate its own generation to serve native load. However, imposing NRIS on QF generation, may result in unnecessary system upgrades. For example, a solar resource may be acceptable of ERIS given their specific business plan and delivery requirements. However, if NRIS is imposed, the host utility may find a need, under conservative study assumptions, that at times there may be insufficient demand in the local area and consequently the need for upgraded or entirely new capacity. Unless the situation results in a violation of NERC/WECC reliability standards that require a RU, the generator should be offered the option of ERIS or NRIS.

Q. Can you provide any examples of how ERIS and NRIS is typically studied outside of the Oregon state process?

A. A good example of study process that allows for a selection of ERIS or NRIS by the generator is the California ISO. While it is important to note that California and Oregon are fundamentally different in terms of power supply, i.e. CAISO operates an energy market while Oregon functions under the more traditional utility approach of utility owned generation and power purchases from third parties, the fundamental system planning and study function are largely the same. With the CAISO process, which includes all three of the large Load Serving Entities (PG&E, SCE, and SDG&E), the generator is presented with the costs associated with energy only (i.e. ERIS) vs. full deliverability (i.e. NRIS) interconnection upgrades. The decision to accept the costs for NRIS is left to the generator or in the case of utility owned generation, the utility, based on their own specific objectives

California is obviously unique in that it has experienced a massive influx of solar generation over the past 10 years which has largely consumed available system capacity. Consequently, the costs for full deliverable status (i.e. NRIS) has significantly increased to the point *that nearly all generators select to go with ERIS type interconnection*. In fact, the CAISO has implemented a step in their process where generators specify if they are willing to fund NRIS type upgrades or go with ERIS. This process step has been going on for roughly the past 5 years, and to date it is my understanding that NRIS has never been selected by a generator due to the treatment of the associated network upgrades.

Q. So, should QFs have the option to select ERIS?

A. Generator developers should be provided with the option to select ERIS or NRIS based on their business objectives, power purchase agreement provisions, and economic assessment of the total project costs to interconnect. This is the most common and prevailing practice across the WECC. In fact, most transmission owners consider the interconnection and transmission service arrangements separately and the decision is left entirely to the developer.

It seems that an obligation to only be able to select NRIS, which is significantly more likely to have the effect of creating unviable economics that would fundamentally have the effect of denying the QF its ability to sell power under the PURPA mandatory purchase obligation is unjust and unfair, particularly given the much higher likelihood to have higher, or even impossible costs, that might not be necessary to get the power to the off-taking utility or load. This seems particularly evident in the case of PacifiCorp, per the CREA study, where projects received $300 MM, 10-year construction timeline type upgrades for similar sized projects under NRIS than under ERIS. ERIS projects on the same lines in the same load pocket had much, much smaller ERIS-only upgrades of just a few million dollars.

IV. CONCLUSION

Q. Do you have any concluding remarks?

A. Oregon's approach of forcing QF generation into the NRIS path is largely inconsistent with other entities I have work on generator interconnections with through the WECC area. Not all generation requires firm transmission service to meet their business objectives and by imposing NRIS and associated costs places generation at a disadvantage economically and can even have the effect of unnecessarily killing a project, as well as effectively subverting the ability of the QF to sell under its mandatory purchase obligation under PURPA. The utility has the ultimate responsibility to serve load, and should be responsible for delivering whatever power it is required to buy to where it would deliver such power; but this is not the obligation of the power facility delivering power to the utility's system. Consequently, I believe the utility should ultimately pay for network upgrades, either directly (in lieu of the generator posting money) or, as is very common, reimburse the generator for these costs. Also, the generator that is funding the system impact study should be offered the option, based on business needs, to select the interconnection service, whether that be ERIS or NRIS based on the host utility study results which should include impacts for both.

Q. Does this conclude your testimony?

A. Yes.

BRIAN RAHMAN, P.E.

EXECUTIVE DIRECTOR, ENGINEERING

Brian Rahman is ZGlobals' Executive Director of Engineering. Brian has over twenty-five years of extensive experience in areas of management of market systems, operations, design and technology updates, and project coordination in a variety of utility/energy-related disciplines. His expertise includes hydro and control area operation, financial analysis of transmission and generation, implementation of large projects and renewable integration. He brings to ZGlobal a unique combination of skills in engineering, operation and energy market implementation and project management, utilizing both his technical and managerial experience.

PROFESSIONAL EXPERIENCE

ZGLOBAL ENGINEERING & ENERGY SOLUTIONS (2006-Present)

Executive Director of Engineering

Brian is our resident expert in Energy Market Implementation. His engineering and technical expertise in Utility Operations in addition to his proven ability in managing large complex projects, enable him to perform both technical and project management responsibilities. Brian oversees the ZGlobal generation interconnection team and has extensive experience with interconnection processes and policies with utilities across the western United States. As our Director of Engineering, Brian manages a team of Power System Engineers responsible for conducting various types of detailed system studies including power flow analysis, short circuit duty, transient stability, protection coordination, loss studies, etc.

CALIFORNIA INDEPENDENT SYSTEM OPERATOR (1997-2006)

MRTU Program Manager and Manager of Program Office

Responsibilities included overall management of the Market Redesign and Technology Upgrade program. This program included the wholesale replacement of all Market Systems, Settlement systems and modifications to approximately 15 supporting applications as well as replacement of the underlying application architecture. Responsible for negotiations and contract relationships with multiple software vendors, service providers, and consulting firms. This was a $170 M program with a contract and staff headcount of 215 people. Role involved routine reporting and interaction with CAISO Board of Governors, FERC, and State regulators.

Manager of: Market Operations, Market Redesign & Technology Update, Special Projects, Market Engineering, Real Time Market Operations, Technical Support for Real-Time Operations

Responsible for the specification, design, procurement, and testing of Real-Time, and Residual Unit Commitment Markets. Provided management and coordination for multiple project groups engaged in the design and implementation of market applications and supporting systems. Oversaw the project requests, budgets, staffing, design documents and contract negotiations. Responsible to insure Tariff and FERC order requirements are represented in market applications and operating procedures. Other responsibilities included Department Capital and O&M Budget development, department and corporate representative for market design and technical implementation expert, oversee the Day-Ahead, Hour-Ahead, and Real-Time energy, transmission and ancillary service markets, insure close coordination with grid operations concerning system load forecast, energy and reserve procurements, insure accuracy of all published prices and settlement quality data. Insured development of detailed design documents for vendor and internally developed software, coordination of software testing and deployment with Market Participants. Project Management responsibilities consisted of overall project development including budget, design, staffing, inter-departmental and Technical Support for Real-Time Operations.

PACIFIC GAS & ELECTRIC (1991-1997)

Electrical Engineer, Hydro Generation, Project Engineering

Prepared job proposals that included cost estimates, engineering calculations, studies and design. Developed equipment and consulting specifications, procurement documents and evaluated proposals for electrical equipment and system revisions and upgrades. Provided engineering guidance and technical support to engineering designers and drafters. Planned, designed and developed routine work plans needed to maintain and improve PG&E hydro facilities.

Distribution Engineer

Provided electric planning and operations support for 12 kV distribution network. Performed load growth studies and developed capacity increase projects as needed for future growth. Provided protection settings for distribution breakers and line equipment to insure coordination of protective devices. Investigated and resolved power quality and voltage complaints. Served as on-call supervisor during off-hour emergencies.

Electrical Engineer, Hydro Generation

Primarily responsible for the facilities located on the Mokelumne and Stanislaus watersheds consisting of 9 powerhouses and a variety of extensive water conveyance systems. Provided construction, maintenance, and operations engineering support for PG&E hydro facilities. Identified equipment problems and developed scope, cost, design, and procurement documents. Provided technical support for maintenance activities, operational constraints, and construction projects. Provided budget input including project alternatives, economic evaluations, and justification. Served as project manager, providing project estimating, justification, schedule and cost tracking. Provided construction coordination and on site engineering. Served as on-call supervisor. Applied Reliability Center Maintenance practices to PG&E hydro facilities. Responsibilities included: Comprehensive review of hydro generation equipment maintenance practices and detailed reviews with maintenance staff, documentation of existing time based practices, and recommended condition based analysis used to trigger maintenance.

Project Coordination

Prepared job proposals that included cost estimates, engineering calculations, studies, and design. Developed equipment/consulting specifications, procurement documents, and evaluated proposals for electrical equipment/system revisions and upgrades. Provided engineering guidance and technical support to engineering designers and drafters. Planned, designed, and developed routine hydro work needed to maintain and improve PG&E hydro facilities.

Engineering Consulting

Solved electrical engineering problems, evaluated and recommended alternative solutions, evaluated equipment and engineering service bids and assisted in the project scope, evaluation and justification.

Power System Engineer

Performed contingency studies, analyzed system disturbances and coordinated switching and clearances for transmission and relay protection maintenance. Monitored system performance and developed Dispatch Operating Instructions. Reviewed transmission and generation planning projects for operational capability, relay coordination and determined impact to generation resources. Performed transformer evaluation studies for use in transformer bank re-rating project and station capability report for planning studies. Developed qualifying facility database and PG&E winter electric system base-case. Worked on procedure for Diablo Canyon Power Plant black-start.

NOTABLE PROJECTS

Generator Interconnection Process, Project Specification, and Technical Requirements (2007 – 2018)

Brian has been at the forefront of the generation interconnection boom across the western united states (NVE, CAISO, PG&E, SCE, SDG&E, IID, APS, PJM, PNM) and has assisted with 100's of interconnection applications including preliminary technical specification of the generation/storage project and components, development of single-line drawings, site maps, complex modeling of project dynamic characteristics, and liaison with utility or transmission owner. His efforts in this area include due-diligence services including power flow analysis and system capacity assessments in the selection of points of interconnection, guidance throughout the interconnection study process, and interconnection agreement. Project technologies have included traditional gas generation, hydro generation, pumped storage, wind, solar PV, energy storage, geothermal as well as emerging technologies.

Annual Review of Southern California Edison Transmission Capital Projects for the CUPC (2015 and 2016)

Brian was the principal engineer and team lead for the annual reviews of SCE transmission capital projects and provided power flow analysis and validation of proposed project needs. Project assessments were performed for projects exceeding

$50 Million and involved independent assessment of the projects and development/evaluation of possible alternatives. Efforts included coordination with CPUC and SCE to validate projects against prevailing design standards, variations in load/demand forecasts, and possible alternatives. In both years, the assessment found projects that were deferred or canceled based on the analysis leading to a savings for SCE ratepayers.

Deliverability Assessment - Tehachapi Renewable Transmission Project Impacted Generation (2010-2016)

Brian performed a detailed deliverability assessment for wind and solar generation projects, existing and proposed, in the Tehachapi wind area that were exposed to potential curtailment or deliverability limits due to the construction of the Tehachapi Renewable Transmission Project (TRTP). The construction of the TRTP spanned multiple years and multiple configurations before completion. The analysis considered all these variables and was refreshed several times due to changes in proposed generation and delays in completing several phases of the TRTP. The analysis and results enabled our client to plan for and mitigate possible periods of production limitations and was used for financing purposes for project expansion efforts within the Tehachapi area. The analysis included both production cost simulations as well as power flow analysis so that both energy prices as well as the physical capacity of the system was incorporated into the overall analysis and resulting conclusions.

California Department of Water Resources – California Water Fix (2010-2017)

Brian served as Consulting Manager over engineering team in the development of dynamic models (GE_PSLF) for Tunnel Boring Machines to allow for SMUD and WAPA to perform System Impact Studies and dynamic simulations to assess possible impact to the bulk electric system. In this role, Brian provided CDWR management with guidance and support during the Study process with SMUD and WAPA, evaluated study results and recommendations to enable CDWR to meet its objectives with early phases of project work for CA Water Fix Project. Brian has been involved with the CA Water fix project from the early stages beginning with the first System Impact Study, performed under his direction, to assess impacts and upgrades to the WAPA system required to support construction and operational power needs for the project.

TESTIMONIES

"Arbitration Findings and Award in Cities of Anaheim et al. v. the ISO & Southern California Edison regarding "Allocation of Transmission Cost", Rahman, B., Testimony, Docket No. EL03-54-000, August 27, 2003 [View PDF: http://zglobal.biz/pdf/DocketNo_EL03-54-000_SouthernCitiesv_CaliforniaISO.pdf]

"Ancillary Service Must Offer Obligation and Resource Adequacy Standard Capacity Product", Testimony submitted by Brian Rahman to FERC, Docket No. ER 09-1064-000, April 28, 2009

"Investigation of Wholesale Rates of Utility Sellers of Energy and Ancillary Services in the Western Systems Coordinating Council" testimony provided By Brian Rahman, MRTU Director to FERC, Docket No. EL01-68-017, ER02-1656-030, ER02-1656-009, Docket No. ER06-615-000, March 15, 2006

"Long-Term Firm Transmission Rights in Organized Electricity Markets" proposal by Brian Rahman, Program Director of CAISO Market Re-design and Technology Upgrade (MRTU), Submitted to FERC Docket Nos. RM06-8-000 and AD05-7-000, March 13, 2007. [View PDF: http://zglobal.biz/pdf/Docket%20No_RM06-8_Long_TermFirmTransmissionRights.pdf]

"Post-Technical Conference Response of the California Independent System Operator Corporation on Business Practice Manual Issues", Brian Rahman, Program Director of CAISO Market Re-design and Technology Upgrade (MRTU), submitted to FERC in March 2007, Docket # ER06-615-012 and ER 07-1257-000 [View PDF: http://zglobal.biz/pdf/MRTU_DocketNos_ER06-615-012.pdf]

"California Independent System Operator Corporation Electric Tariff Filing to Reflect Market Redesign and Technology Upgrade", Docket No. ER06, declaration and testimony of Brian Rahman, Program Director of CAISO Market Re-design and Technology Upgrade (MRTU), Submitted to FERC on February 9, 2006. [View PDF: http://zglobal.biz/pdf/AttachmentM-DirectTestimony-BrianRahman_ExhibitNo_ISO-8.pdf]

"Tesoro Refining & Marketing Co. LLC v. Pacific Gas and Electric Co." Case No. 3:14-cv-00930 in the U.S. District Court of California. Provided Expert Witness Testimony on behalf of Tesoro Refining and Marketing including written testimony, rebuttal, and on the stand questioning and cross examination.

Imperial Irrigation District v. California Independent System Operator. Docket #3:15-cv-01576-AJB-AGS in the US District Court- Southern California. Provided testimony on Transmission Operations between the two balancing authorities on behalf of the IID.

"California Solar Ranch v. Area Energy" JAMS Ref. No. 1100088728. Provided Expert Witness Testimony on Behalf of Area Energy including written testimony, rebuttal, questioning and cross examination.

EDUCATION & CERTIFICATIONS

B.S., Electrical Engineering, Washington State University

Registered Professional Electrical Engineer, State of California. E14914

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON
Docket No. UM 2032

In the matter of

PUBLIC UTILITY COMMISSION OF OREGON,

Investigation into the Treatment of Network Upgrade Costs for Qualifying Facilities

RESPONSE TESTIMONY OF BRITTANY ANDRUS

October 30, 2020

I. INTRODUCTION

Q. Please state your name and occupation.

A. My name is Brittany Andrus. I am currently self-employed as a consultant in the energy industry.

Q. Please describe your background and experience.

A. I was employed as a Utility Analyst on the Staff of the Oregon Public Utility Commission (OPUC or Commission) for eight years, from 2011 to 2019, during which time I provided analysis, testimony, and recommendations to the Commission on water, natural gas and electric regulatory filings. From 2013 through the majority of 2019, as Senior Utility Analyst, I was the principal Staff on OPUC cases involving Public Utility Regulatory Policies Act ("PURPA") policies and regulations in Oregon, including general policy investigations and utility-specific dockets.[1] Specific to qualifying facility (QF) interconnection, I facilitated the Interconnection Data Workgroup authorized by the

[1] *Rulemaking Regarding Power Purchases by Public Utilities From Small Qualifying Facilities,* Docket No. AR 593; *Investigation into Qualifying Facility Contracting and Pricing,* Docket No. UM 1610; *Broad Investigation into PURPA Implementation*, Docket No. UM 2000; *Investigation into Interim PURPA Action: Interconnection Data and Interim Pricin*g, Docket No. UM 2001; *Application to Update Schedule 201 Qualifying Facility Information (post-Carty Generating Station EPC contract),* Docket No. UM 1664 (PGE); *Updates to Schedule 201 Qualifying Facility (10 MW or less) Avoided Cost*, Docket No. UM 1728 (PGE); *Updates Qualifying Facilities Avoided Cost Payments*, Docket No. UM 1729 (PacifiCorp); *Updates Qualifying Facilities Avoided Cost Payments, Schedule 85,* Docket No. UM 1730 (Idaho Power); *Revised Schedule 201 Qualifying Facility Information, Consistent with the 2013 Integrated Resource Plan Update*, Docket No. UM 1752 (PGE); *Application for Approval of Solar Integration Charge,* Docket No. UM 1793 (Idaho Power); *Investigation into Schedule 37 Avoided Cost Purchases,* Docket No. UM 1794 (PacifiCorp).

Commission in 2019, resulting in the posting of information about each utility's distribution system on its Open Access Same-time Information System (OASIS).[2] Prior to the Commission, I worked as Public Utilities Specialist for Bonneville Power Administration from 1992 to 2009 in a variety of functional areas, including long-term power sales forecasting, contracting, rates and product analysis, meter data management, and in power operations scheduling and short-term forecasting. Please see my attached witness qualification statement attached as NewSun/201.

Q. On whose behalf are you appearing in this proceeding?

A. I am testifying on behalf of NewSun Energy.

Q. Please summarize your testimony.

A. My testimony responds to the Joint Utilities' Direct Testimony and in response to the two questions in the scope of this phase of this investigation[3]:

1. Who should be required to pay for Network Upgrades necessary to interconnect the QF to the host utility?
2. Should on-system QFs be required to interconnect to the host utility with Network Resource Interconnection (NRIS) or should QFs have the option to interconnect with Energy Resource Interconnection Service (ERIS) or an interconnection service similar to ERIS?

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[2] *Staff Investigation into Interim PURPA Action*, Docket No. UM 2001, Order No. 19-217 (June 21, 2019) *available at* https://apps.puc.state.or.us/orders/2019ords/19-217.pdf. Information posted includes Feeder Voltage, No. of Transformers, No. of Feeders, Location, Feeder SCADA Y/N, Feeder Name/Designation, Feeder Load Peak, Feeder Capacity, Existing Distributed Resources Connected, Proposed Distributed Resources in Queue, and Minimum Daytime Load.

[3] Ruling (May 22, 2020).

In responding to these two questions, I provide an overview of the evolution of the Oregon interconnection rules and policies for network upgrades, I discuss the impacts these rules and policies have had on QF interconnections in Oregon, and I review how changes to the current system can help Oregon achieve its climate goals. Finally, I recommend that QFs should be reimbursed for all system upgrades other than those that demonstrably benefit only a single facility and that QFs should have the option of interconnecting via either ERIS or NRIS.

II. EVOLUTION OF OREGON INTERCONNECTION RULES AND POLICIES FOR NETWORK UPGRADES

Q. The Joint Utilities state that they do not believe the small generator interconnection rules are at issue in this docket, and that the small generator rules will be addressed in Docket No. UM 2111 "where all interested generators (QF and non-QF) will have an opportunity to participate."[4] Do you agree that the Small Generator Interconnection Rules are not at issue in this docket?

A. No. The issue list adopted in this docket does distinguish between small and large QFs, but asks who should pay for Network Upgrades necessary to interconnect the QF to the host utility and whether on-system QFs should have the option to connect with either Network Resource Interconnection Service (NRIS) or Energy Resource Interconnection Service (ERIS). To the extent that the Oregon small generator rules (OR SGIR) address the allocation of the costs of system upgrades for QFs, they should be in the scope of this investigation. As the Joint Utilities correctly identify, the small generator rules specifically addresses system upgrade costs:

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4 Joint Utilities/100, Vail-Bremer-Foster-Larson-Ellsworth/11. Given the current dispute over whether the Joint Utilities appropriately struck their testimony in response to the ALJ's October 10, 2020 Ruling Granting the Motion to Strike in Part, for the sake of clarity all cites to the Joint Utility's testimony will refer to the revised testimony filed by the utilities on October 19, 2020.

> System upgrades. A public utility must design, procure, construct, install, and own any system upgrades to the public utility's transmission or distribution system necessitated by the interconnection of a small generator facility. A public utility must identify any adverse system impacts on an affected system caused by the interconnection of a small generator facility to the public utility's transmission or distribution system. The public utility must determine what actions or upgrades are required to mitigate these impacts. Such mitigation measures are considered system upgrades as defined in these rules. The applicant must pay the reasonable costs of any system upgrades.[5]

Because many QFs are small generator facilities with a nameplate capacity of 10 MW or less, any changes to the cost allocation policy logically would apply to any QF interconnection, regardless of whether it is considered "large" or "small."

Q. Does Oregon have corresponding rules for large generator interconnection?

A. No. Large generator interconnection was addressed in Docket No. UM 1401. That docket was opened as a result of a Staff Report precipitated by Docket No. AR 526, a rulemaking to update Division 029 due to 2007 legislative changes and Commission Order No. 07-360 in Docket UM 1129.[6] The Staff report requested that the Commission open an investigation into interconnection of PURPA QFs with a nameplate capacity

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5 OAR 860-029-0035(4).

6 *Rulemaking to Update Division 029 Rules*, Docket No. AR 526, Division 029, Notice of Proposed Rulemaking Hearing (Apr. 15, 2008) ("This is the first phase of rulemaking to update the Division 029 rules. The proposed amendment to 860-029-0001 is resultant from 2007 legislative changes, specifically Senate Bill 838, Section 27(4). The proposed rule 860-029-0100 is resultant from Commission Order No. 07-360 in docket UM 1129. In that order, the Commission clarified its intent regarding the scope of a proceeding where a complaint is filed regarding the negotiation of a Qualifying Facility power purchase agreement. The dispute resolution procedures are intended to reduce the time and costs in resolving disputes for customers, utilities and the Commission. Further updates to the Division 029 rules, as a result of Commission Orders in docket UM 1129 and changes in federal and state law, will be addressed in a second phase of this rulemaking") *available at* https://edocs.puc.state.or.us/efdocs/HAA/ar526haa94155.pdf.

larger than 10 MW to a public utility's transmission or distribution system.[7] This staff report provides context for the various QF and interconnection-related dockets:

> At staff's AR 526 workshop on August 7, 2008, the utilities and other stakeholders supported the concept of using FERC's small generator interconnection agreements for QFs between 10 MW and 20 MW, and FERC's large generator interconnections and agreements for QFs over 20 MW, until the Commission establishes interconnection rules for these generators.
>
> Originally, staff believed the Commission could adopt these procedures and agreements in AR 529. However, after consulting with the Hearings Division, staff's attorney advises that the Commission should instead do so through an investigation. The investigation will allow the utilities to slightly modify their FERC-approved filings as necessary to make them fit within Oregon's regulatory scheme. For example, the utilities may specify that the small generator procedures and agreements are available to QFs over 10 MW (smaller QFs will be subject to the Commission's order in AR 521), change references such as "FERC" to "PUC" and "Transmission Provider" to "public utility," specify that the Commission's dispute resolution procedures will be used instead of FERC's, and confirm the FERC interconnection procedures and agreements to the Commission's decisions in AR 521 as necessary. However, staff does not expect the utilities to change the FERC-approved procedures and agreements in any material way.
>
> Staff recommends each utility file its draft modifications to the FERC-approved procedures and agreements no later than 120 days of granting staff's motion to open the investigation. The filing should include redline versions showing all changes made to the FERC-approved documents as well as an explanation of the proposed modifications.[8]

Docket No. AR 521 was in progress to address rules for interconnection of small generators of 10 MW or less. The report explains that Division 029 rules contain many

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[7] *Investigation into Interconnection of PURPA Qualifying Facilities With Nameplate Capacity Larger Than 20 Megawatts to a Public Utility's Transmission or Distribution System*, Docket No. UM 1401, Staff Report for November 4, 2008 public meeting, (Oct. 28, 2008) *available at* https://edocs.puc.state.or.us/efdocs/HAA/um1401haa1142.pdf.

[8] *Id.* at 2-3.

references to interconnection of QFs but "do not provide uniform technical standards or uniform procedures and terms for interconnection agreements."[9]

Q. Please describe the initial stages of Docket No. UM 1401.

A. The docket was opened at the public meeting on November 4, 2008. In February, 2009, the administrative law judge suspended the schedule for submission of draft interconnection procedures and agreements for QFs larger than 10 MW and no larger than 20 MW, stating, "[a]fter the decision in AR 521 is issued, the parties should inform the Commission of how they plan to proceed to create procedures and agreements for these QFs."[10]

Q. Was interconnection of QFs in that 10 to 20 MW size range addressed after the small generator interconnection rules were adopted in Docket No. AR 521?

A. Not to my knowledge.

Q. How do Joint Utilities characterize the Commission direction in Docket No. UM 1401?

A. Joint Utilities state that "the Oregon Commission directed transmission providers to eliminate Section 11.4.1 of FERC's pro forma LGIA from the Oregon QF-LGIA. Section 11.4.1 is the provision that entitles an interconnection customer to be reimbursed for the cost of its Network Upgrades through payment of transmission credits over time."[11] They then cite the Commission's rational for rejecting FERC's interconnection cost allocation policy as stated in Order No. 10-132.

Q. Do you agree with Joint Utilities' characterization of the Commission's direction?

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9 *Id.* at 2.
10 Docket No. UM 1401, Ruling (Feb. 12, 2009).
11 Joint Utilities/100, Vail-Bremer-Foster-Larson-Ellsworth/24.

A. No. While, the Commission's decision in the April 7, 2010 order rejected the FERC interconnection cost allocation policy, multiple actions occurred in the course of the docket between its opening in November 2008 and the issuance of the final order.

Q. Please describe the intervening actions.

A. After the scope was limited to QFs larger than 20 MW in February 2009, the three utilities filed draft interconnection procedures and agreements in March 2009. Each filing contained contain similar reasoning for removing Article 11.4 of the LGIA requiring the Transmission Provider to reimburse the Interconnection Customer for the cost of network upgrades.[12]

Q. Were the utilities directed to file draft documents that included these changes?

A. I can find no language from the Commission directing the utilities to propose specific language or changes to the FERC LGIA and LGIP. In fact, the Commission adopted the report in which Staff stated it did not "expect the utilities to change the FERC-approved procedures and agreements in any material way."[13] It appears that the utilities were the first to propose removing references to Energy Resource Interconnection Service (ERIS) and Article 11.4 regarding allocation of network upgrades. As Idaho Power explains it,

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12 Docket No. UM 1401, Pacific Power's Comments and Draft Interconnection Procedures and Agreements, (Mar. 5, 2009) *available at* https://edocs.puc.state.or.us/efdocs/HAH/um1401hah134947.pdf; Docket No. UM 1401, Portland General Electric Company's Draft Interconnection Procedures and Agreements for Qualifying Facilities (Mar. 9, 2009) *available at* https://edocs.puc.state.or.us/efdocs/HAH/um1401hah10224.pdf; Docket No. UM 1401, Idaho Power Company's Opening Comments and Submission of Draft Interconnection Procedures and Agreement (Mar. 9, 2009) *available at* https://edocs.puc.state.or.us/efdocs/HAH/um1401hah101122.pdf.

13 Docket No. UM 1401 Staff Report for November 4, 2008 public meeting, (Oct. 28, 2008).

The purpose of the docket is to develop a set of policies and procedures to govern the interconnection of larger QFs to the utilities' transmission systems, pending adoption of final rules on the subject. Towards this end, the Commission has ordered the utilities to start with the interconnection agreements and procedures adopted by the Federal Energy Regulatory Commission ("FERC") for FERC jurisdictional large generator interconnections, and to file redlined versions of those documents with those changes the utilities believe necessary in this context. Accordingly, the utilities have agreed to file redline versions of the FERC Large Generator Interconnection Agreement ("LGlA") and Large Generator Interconnection Procedures ("LGlP"), along with Comments that provide explanations for their positions. For the purposes of this filing, the redlined FERC LGIA has been relabeled "Large Generator Interconnection Agreement for Oregon Qualifying Facilities" or "LGIA-OR." The redlined FERC LGIP has been relabeled "Large Generator Interconnection Procedures for Oregon Qualifying Facilities" or "LGIP-OR."

Idaho Power has made two substantive changes to the FERC documents to produce the LGIA-OR and LGIP-OR. First, Idaho Power has removed Article 11.4, which governs the allocation of network upgrade costs. Under Article 11.4 of the LGIA, interconnecting QFs are required to pay the initial costs of network upgrades necessitated by the interconnection. The utility, however, must refund those costs over time through a credit to the QF for transmission charges. Idaho Power removed this article because the allocation of the costs of network upgrades to ratepayers conflicts with PURPA requirements that utility customers remain indifferent to QF power. Instead, Idaho Power advocates that any interconnection or network upgrade costs should be paid by the QF causing the costs and no other. This rule will create a clear-cut system that is easy to implement, prevents future disputes among QFs, and will protect ratepayers from subsidizing QF costs.

The second substantive change proposed by Idaho Power is the deletion from the LGIA and LGIP of references to Energy Resource Interconnection Service. As described in comments included directly in the LGIA-OR, all QF services covered by that agreement will be Network Resource Interconnection service, and therefore the reference to Energy Resource Interconnection Service is not needed.[14]

Q. What followed the March 2009 utility filings?

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[14] Docket No. UM 1401, Idaho Power Company's Opening Comments and Submission of Draft Interconnection Procedures and Agreement at 1-3 (Mar. 9, 2009).

A. Comments were filed by Staff, the Industrial Customers of Northwest Utilities (ICNU) and the Oregon Department of Energy in June and August 2009. In November 2009, the Chief Administrative Law Judge issued a bench request for several items, including the utilities' removal of ERIS from the draft documents: "Article 4.1.1 of the QF-LGIA, removes the option of Energy Resource Interconnection Service. The removal was not addressed by the parties during the comment periods. Explain the justification for removing the option of Energy Resource Interconnection Service, and provide examples of negative consequences of retaining this option."[15] In their response, the utilities refer to the Commission direction in Order No. 07-360 to address transmission costs as part of interconnection rather than as an adjustment to the avoided cost rates the utility pays for the OF's output.[16] The next substantive action in Docket No. 1401 was the issuance of Order No. 10-132.

Q. Were concerns raised in comments regarding the initial interconnection documents filed by the utilities?

A. Yes. ICNU expressed concern over the Utilities' deletion of Article 11.4 from the FERC LGIA, and challenged their assertion that reimbursing the costs of network upgrades to QFs violate the requirement under PURPA that customers remain indifferent to QF power, reasoning that network upgrades benefit all customers. ICNU proposed a direct payment mechanism, under which large QFs would recover the cost of network upgrades from the utility through "either: 1) direct payments made on a levelized basis over the

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[15] Docket No. UM 1401, Bench Request (Nov. 30, 2009).

[16] Docket No. UM 1401, Joint Response to Bench Request (Dec. 29, 2009) *available at* https://edocs.puc.state.or.us/efdocs/HAC/um1401hac161311.pdf.

five-year period commencing on the commercial operation date of the QF; or 2) any alternative payment schedule that is mutually agreeable to the large QF and the participating utility and does not affect avoided cost rates."[17]

Q. How did the Commission resolve this issue?

A. Order No. 10-132 states:

> As noted by the Utilities, transmission costs and network upgrades are included in the calculation of avoided cost rates. Consequently, QFs are currently compensated for these costs pursuant to the rates established in their respective purchased power agreements with the utilities. For this reason, we conclude that Article 11.4 should be modified such that Interconnection Customers are responsible for all costs associated with network upgrades unless they can establish quantifiable system-wide benefits, at which point the Interconnection Customer would be eligible for direct payments from the Transmission Provider in the amount of the benefit.
>
> We are not persuaded by ICNU's arguments that requiring Transmission Providers to pay for network upgrades would not affect the avoided cost rate and thus impose higher costs on the ultimate ratepayer. ICNU's reliance on the reimbursement provisions set forth in the CA-LGIA is misplaced, as the CA-LGIA is a FERC tariff that is not bound by the limitations imposed by PURPA. Moreover, ICNU's argument that FERC has long held that Network Upgrades provide system wide benefits is not persuasive to this point. None of the authorities cited are related to facilities governed by PURPA and thus none faced the limitation of the avoided cost rate.[18]

The result is that the ERIS option is eliminated under the Oregon QF LGIP and LGIA, as is Article 11.4's provision for refunds of amounts expended on network upgrades.

Q. You mentioned above that Oregon's Small Generator Interconnection Rules also dealt with system upgrades. What is your understanding of how the Commission resolved to treat system upgrades for small generators relative to how FERC resolved the issue?

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[17] Docket No. UM 1401, ICNU Opening Comments (June 8, 2009) *available at* https://edocs.puc.state.or.us/efdocs/HAC/um1401hac113419.pdf

[18] Docket No. UM 1401, Order No. 10-132 at 2-3 (Apr. 7, 2010).

A. In the small generator rulemaking, AR 521, the Commission stated:

> Under the Federal Energy Regulatory Commission's rules governing small generator interconnection, there is a process for sharing the cost of system upgrades among small generator facilities using transmission credits. ICNU argues that a similar process should be included in our small generator interconnection rules to ensure that one small generator facility does not pay the entire cost of system upgrades that primarily benefit the public utility or other small generators. ICNU also fears that a public utility might require a small generator to pay for system upgrades that the utility planned to make with or without the small generator's interconnection.
>
> Because not all small generator facilities under this Commission's jurisdiction will be using a public utility's transmission system, a process allowing cost sharing of system upgrades using transmission credits is not feasible. The participants in the rulemaking process were unable to find another method of sharing such costs. The proposed rules, however, include language that is meant to strictly limit a public utility's ability to require one small generator facility to pay for the cost of system upgrades that primarily benefit the utility or other small generator facilities, or that the public utility planned to make regardless of the small generator interconnection. Under the proposed rules, a public utility may only require a small generator facility to pay for system upgrades that are "necessitated by the interconnection of a small generator facility" and "required to mitigate" any adverse system impacts "caused" by the interconnection. We therefore believe the proposed rules adequately protect small generator facilities and that ICNU's fears are unfounded.[19]

Q. Can you expand on the Commission's statement regarding the infeasibility of implementing a cost sharing mechanism using transmission credits?

A. Yes. I believe the Commission is pointing out that some small generators interconnecting under Division 082 will not use the transmission system, such as those with impacts only on the distribution system. Also, transmission service for QFs is not acquired by the QF; transmission service is acquired by the utility merchant function from the transmission function of that utility, so a QF could not directly receive credit via offsets to its transmission service costs. However, the fact that not all small generators use the

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[19] Docket No AR 521, Order No. 09-196 at 4-5 (June 8, 2009).

transmission system should not be an impediment to providing for the reimbursement of system upgrade costs to those who do use it, as those upgrades are likely to provide broader system benefits. I am hopeful that in phase II of this proceeding, a range of robust approaches for cost sharing will be explored.

Q. In your view, has the language meant to strictly limit system upgrade costs borne by the QFs that benefit other small generators or that the utility planned to make?

A. No. In practice, ICNU's fears were realized. In addition to there being no incentive for the utility to minimize potential system upgrade costs (and in fact there is a disincentive, as described below), there is no established process for determine which system upgrades would fall into those categories. The consequence has been prohibitively high system upgrade cost for many renewable generators, making those proposed projects uneconomic.

Q. What is your understanding of how the Commission resolved the NRIS vs. ERIS issue for small generators relative to how FERC resolved the issue?

A. The Commission did not discuss NRIS or ERIS in its AR 521 order. With regard to small generators FERC has stated:

> We clarify that the resource options listed in the Small Generator Interconnection NOPR's Interconnection Request are not interconnection service options. Rather, they are merely the possible ways the Interconnection Customer may use its Small Generating Facility once delivery service begins. The purpose of this information is to give the Transmission Provider an early indication of how the Small Generating Facility is likely to operate. The one interconnection service that the Commission proposed to make available to the Small Generating Facility is similar to the Energy Resource Interconnection Service that is offered under the LGIA. Nevertheless, based on the comments, we are concerned that requesting service-related information in the Interconnection Request could lead to misunderstanding. Because the information is related to the delivery component of transmission service, not interconnection service, it is not needed in the SGIP's Interconnection Request form. Therefore, we are

> removing this information from the Interconnection Request. This should address the concerns of most commenters.
>
> In response to National Grid, we note that the LGIA's more expansive Network Resource Interconnection Service is intended to give the Interconnection Customer broad access to the backbone of the Transmission Provider's Transmission System. In essence, it allows the generating facility to pre-qualify as a Network Resource for any Network Customer on the Transmission System and, as National Grid notes, may make it eligible for installed capacity credits. Because Network Resource Interconnection Service entails high technical standards, we expect that an Interconnection Customer, particularly one interconnecting at a lower voltage, would rarely find this service to be efficient or practical. Nevertheless, we do not want to preclude it from choosing this option. If it wishes to interconnect its Small Generating Facility using Network Resource Interconnection Service, it may do so. However, it must request interconnection under the LGIP and execute the LGIA.[20]

In Order No. 792, FERC in 2013 adopted a number of refinements and improvements to improve and expedite the process of interconnecting small generators (those with less than 20 MW of capacity). However, FERC retained the small generator's option to use NRIS, at the generator's option. As it explained:

> The Commission [in its Notice of Proposed Rulemaking] proposed to revise section 1.1.1 of the pro forma SGIP to require Interconnection Customers wishing to interconnect its Small Generating Facility using Network Resource Interconnection Service to do so under the LGIP and execute the LGIA. The Commission explained that this requirement was included in Order No. 2006 but was not made clear in the pro forma SGIP. To facilitate this clarification, the Commission also proposed to add the definitions of Network Resource and Network Resource Interconnection Service to Attachment 1, Glossary of Terms, of the pro forma SGIP.[21]

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[20] Order No. 2006, *Standardization of Small Generator Interconnection Agreements and Procedures*, FERC Docket No. RM02-12 at PP 139-140 (2005) *available at* https://www.ferc.gov/sites/default/files/2020-04/20050512110357-order2006.pdf.

[21] Order No. 792, *Small Generator Interconnection Agreements and Procedures*, 145 FERC ¶ 61,159 at P 232 (2013) (available at: https://www.ferc.gov/sites/default/files/2020-06/RM13-2-000_0.pdf).

It adopted this proposal in Order No. 792.[22] As the Commission's explanation makes clear, NRIS is used for small generators only if the small generator elects to use it for economic reasons.

Q. The Joint Utilities refer to "fragmented rules and policies applicable to generators of various sizes."[23] Based on your experience with Oregon's implementation of PURPA as it pertains to interconnection, do you agree with this description?

A. Yes. In addition to the gap due to a lack of specified rules for generators of 10 to 20 MW, there are some interconnection rules specific to QFs contained in Division 029, and then separate rules for small generator interconnections that are not specific to QFs contained in Division 082, and no codified rules for "large" QF generators (>20 MW), but the QF LGIP and QF LGIA that came out of Docket No. UM 1401. This is not to mention the additional fragmentation due to PacifiCorp's newly approved large generator process and agreement different from the QF-LGIP and QF-LGIA and waiver from parts of the small generator rules.[24]

III. NEGATIVE IMPACTS OF OREGON'S QF NETWORK UPGRADE COST ALLOCATION POLICIES

Q. Can you describe the overall impacts of the current system?

A. By adopting an interconnection network upgrade cost allocation policy that is so significantly different from the FERC *pro forma*, Oregon has created a framework in which the utility has no incentive to identify least-cost, reliable solutions to integrating QF renewable energy resource onto their systems. QFs are by definition "competition"

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22 *Id.* at P 235.

23 Joint Utilities/100, Vail-Bremer-Foster-Larson-Ellsworth/12.

24 *Pacificorp, dba Pacific Power Application for an Order Approving Queue Reform Proposal*, Docket No. UM 2108, Order No. 20-268 (Aug. 19, 2020).

for the utility. Utilities do not receive a return on investment for QF power purchase agreements, as they do for their own energy resources. There is no mechanism for collaboration between resource developers and the utility to plan for efficient use and expansion of the transmission system.

Joint Utilities express concern about inefficient siting of QFs, stating, "[R]equiring a generator to pay for its interconnection costs thus serves two purposes: (1) it ensures that costs are allocated consistent with principles of cost-causation, and (2) it disincentivizes generators from siting projects in locations where interconnection costs are particularly expensive or inefficient."[25] Conversely, there is no incentive for the utility to proactively identify efficient sites for its competition. There is no incentive for the utility to identify creative solutions for interconnecting and delivering renewable QF resources, or to facilitate cost-sharing among generators and the utility. The current system is very inefficient.

Q. What about the cost causation principle?

A. Cost causation is an important principle in utility regulation. It is possible that a single generator might locate somewhere and create network upgrade costs that no other customer would ever benefit from. But that case is the exception. As Oregon ramps up development of renewable resources, most system upgrades necessitated by interconnection of a QF will provide benefits to all customers in that the infrastructure will be used by additional renewable projects, and the system will be more resilient for power customers. Costs cannot be considered without considering commensurate

[25] Joint Utilities/200, Wilding-Macfarlane-Williams/9.

benefits. Additionally, the burden of demonstrating that there is a system benefit customers will derive from its system upgrade is proportionately heavier for a QF than the opposite burden (to demonstrate there is no benefit to the system) is for the utility, simply based on the disparate information available to each party.

Q. Is the requirement to demonstrate system-wide benefits in order to receive repayment of upgrade costs a significant hurdle to QFs in Oregon?

A. Yes. The current system requires the QF to bear the cost and puts the burden on the QF to demonstrate system-wide benefits. Based on my experience as OPUC Staff, I believe that it would be an incredibly burdensome process for the QF to obtain adequate information from the utility in order to pursue a complaint against the utility and demonstrate system-wide benefits. Many QFs would be unable or unwilling to pursue such an action. I am unaware of any QF having made such a demonstration to a utility and receiving repayment.

Q. Would you characterize the requirement to interconnect with NRIS without the option to interconnect with ERIS as a significant hurdle to QFs in Oregon?

A. Yes, I believe it is, based on my experience as OPUC Staff.

Q. Have initiatives that are not specific to PURPA been negatively impacted by the specific requirements for small generators to pay for system upgrades?

A. Yes. The prospect of prohibitively high system upgrade costs, as well as other interconnection costs, has been a major issue in Docket No. UM 1930, Community Solar Program (CSP) Implementation. CSP projects are sized at 3 MW or lower. In that docket, stakeholders expressed concerns that interconnection costs may prevent successful launch of the CSP.[26] After a significant amount of discussion among the many stakeholders, Staff and the utilities, the Commission adopted the Staff recommendation for a "Simplified CSP interconnection process."[27]

IV. OREGON'S CLIMATE GOALS AND RENEWABLE ENERGY

Q. What generally are Oregon's goals and mandates for renewable energy and reducing greenhouse gases (GHGs)?

A. On March 10, 2020, Oregon Governor Kate Brown issued Executive Order 20-04, establishing GHG Emissions Reduction Goals. The Order calls for Oregon to reduce its GHG emissions (1) at least 45 percent below 1990 levels by 2035; and (2) at least 80 percent below 1990 levels by 2050.[28] This Order also directs agencies to "exercise any and all authority and discretion vested in them by law to help facilitate Oregon's achievement of the GHG emissions reduction goals set forth in . . . this Executive Order."[29]

In 2016, the passage of Senate Bill 1547 amended Oregon's Renewable Portfolio Standard (RPS), requiring 50 percent of the electricity that is used in the state to come from renewable resources and the removal of coal from the state's electricity supply by 2040. I perceive Oregon as a leader in climate and renewable energy initiatives and believe it is reasonable to expect that Oregon will continue to pursue initiatives that

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26 *Community Solar Program Implementation*, Docket No. UM 1930, Order No. 19-392 at Appendix A at 37 (Nov. 8, 2019) *available at* https://apps.puc.state.or.us/orders/2019ords/19-392.pdf.

27 *Id.*

28 Office of the Governor of the State of Oregon, Exec. Order No. 20-04 at 5 (Mar. 10, 2020) *available at* https://www.oregon.gov/gov/Documents/executive_orders/eo_20-04.pdf.

29 *Id.*

accelerate the development of renewables such as an increase to the RPS mandate or other programs or efforts initiated by or expedited by the agencies in response to the Governor's Executive Order.

Q. Given the magnitude of these GHG goals, is it reasonable to believe that Oregon will require significant new investments in renewable generation?

A. Yes, absolutely.

Q. Similarly, is it reasonable to believe that Oregon's GHG goals will require significant new investments in transmission infrastructure?

A. Yes, absolutely. In particular, the most productive solar resource in Oregon is located in areas where there is very little load, so transmission capacity is limited. In order to efficiently develop the solar energy resources among all the resources that will be required, the process for funding and delivering system upgrades will need to undergo significant change.

Q. Would you say that changes to Oregon's network upgrade cost allocation system and the utility requirement to take NRIS would help Oregon achieve its GHG goals?

A. Yes. As mentioned, the current system suppresses renewable generation and efficient use and expansion of the transmission system, both of which are badly needed to meet Oregon's ambitions climate goals.

V. RECOMMENDED CHANGES TO INTERCONNECTION SYSTEM UPGRADE COST ALLOCATION POLICIES

Q. What changes do you recommend to the current rules and policies?

A. QFs should be reimbursed for all system upgrades other than those that demonstrably benefit only a single facility. Additionally, QFs should have the option of interconnecting via either ERIS or NRIS. A process with the same effects as the FERC process for cost allocation of network upgrades should be adopted in Oregon.

Q. What about the "customer indifference" standard?

A. The concept that utilities' pay no more than avoided costs is central to PURPA in Oregon. However, I believe that interconnection, transmission and avoided cost policies become conflated over time.

According to the Utilities, removal of Article 11.4 was required because the Commission said in Order No. 07-360, "[t]he utility should not adjust avoided cost rates for any distribution or transmission system upgrades needed to accept OF power. Such costs should be separately charged as part of the interconnection process."[30] However, this is referring to the avoided cost payment. It does not address the question of which party demonstrates whether there are or are not system benefits to the transmission system for any particular upgrade.

Additionally, the Commission in Order No. 10-132 states, "…transmission costs and network upgrades are included in the calculation of avoided cost rates. Consequently, QFs are currently compensated for these costs pursuant to the rates established in their respective purchased power agreements with the utilities. For this reason, we conclude that Article 11.4 should be modified such that Interconnection Customers are responsible for all costs associated with network upgrades unless they can establish quantifiable system-wide benefits, at which point the Interconnection Customer would be eligible for direct payments from the Transmission Provider in the amount of the benefit."[31] However, it is not accurate to say that all QFs are compensated for transmission costs and network upgrades in the avoided cost payments.

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[30] Joint Utilities/200, Wilding-Macfarlane-Williams/5-6.
[31] Order No. 10-132 at 3.

Q. Please explain.

A. Under Order 07-360, the Commission directed that "[t]he utility should evaluate whether there are potential savings due to transmission and distribution system upgrades that can be avoided or deferred as a result of the QF's location relative to the utility proxy plant and adjust avoided cost rates accordingly."[32] Utility resources can include large and costly system upgrades. For example, the plan for PacifiCorp's new 140-mile Gateway West transmission segment in Wyoming was moved up by four years earlier to enable delivery of the additional wind generation. Yet the Commission decided to not include the incremental cost of that transmission in the avoided cost calculations.[33] This is another example of established policies that require revisiting on occasion as the larger environment changes, and another reason to synchronize Oregon's QF and other jurisdictional interconnection policies and programs such as CSP.

However, this concept of upgrades being embedded in the avoided cost rate is a distinct question from the cost responsibility for the upgrades an individual QF. That is because the proxy plant costs would be avoided with any QF. But the individual network upgrades for each QF could vary widely depending on system conditions where it interconnects. Notably, in Order 07-360 the Commission goes on to say that "[t]he utility should not adjust avoided cost rates for any distribution or transmission system upgrades

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32 Docket No. UM 1129, Order No. 07-360, Appendix A at 4 (Aug. 20, 2007).

33 *PacifiCorp, dba Pacific Power Updates Standard Avoided Cost Purchases from Eligible Qualifying Facilities*, Docket No. UM 1729, Order No. 18-273 (July 18, 2019) (declining to adopt the Staff recommendation to, "direct PacifiCorp to work with Staff and stakeholders to develop a reasonable representation of costs associated with building the D2 Segment of Gateway West four years earlier than originally planned.").

needed to accept QF power. Such cost should be separately charged as part of the interconnection process."[34] The Joint Utilities note that they understand this policy to be required in order for the allocation of interconnection costs to be consistent with the "customer indifference" standard.[35] I will not opine on whether I agree with that utility statement and leave that issue to the legal briefing in this docket. However, I don't understand those costs would change the avoided cost calculation. Rather, they would only change the amount of network upgrades the QF would be responsible for – paid back over time under the FERC approach, or allocated to the QF under the current OPUC approach.

VI. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.

[34] Order No. 07-360, Appendix A at 4.
[35] Joint Utilities/200, Wilding-Macfarlane-Williams/5-6.

WITNESS QUALIFICATIONS STATEMENT

NAME: Brittany Andrus

EMPLOYER: Self-employed

ADDRESS: Portland, OR

EDUCATION: Michigan State University, Bachelors of Arts in English

Portland State University, Masters of Business Administration

EXPERIENCE: Oregon Public Utility Commission
Senior Utility Analyst, 2013 – 2019

Oregon Public Utility Commission
Utility Analyst, 2011 – 2013

Bonneville Power Administration
Public Utilities Specialist, Load Forecasting & Analysis, 2008 – 2009

Bonneville Power Administration
Public Utilities Specialist, Project Management Office, 2004 – 2007

Bonneville Power Administration
Public Utilities Specialist, Power Scheduling & Forecasting, 2000 – 2003

Bonneville Power Administration
Public Utilities Specialist, Power Sales Forecasting, Contracts & Rates, 1996 – 1999

Bonneville Power Administration
Public Utilities Specialist, Energy Efficiency Programs & Planning, 1992 – 1995

TESTIMONY:

Docket No. UE 294, Portland General Electric, Request for a General Rate Revision, Opening Testimony
Docket No. UG 221, Northwest Natural, Request for a General Rate Revision, Opening Testimony
Docket No. UM 1610, Investigation into Qualifying Facility Contracting and Pricing, Response Testimony, Ph. II
Docket No. UM 1610, Investigation into Qualifying Facility Contracting and Pricing, Response Testimony (solar issue)
Docket No. UM 1610, Investigation into Qualifying Facility Contracting and Pricing, Reply Testimony, Ph. II
Docket No. UM 1610, Investigation into Qualifying Facility Contracting and Pricing, Opening Testimony, Ph. II
Docket No. UM 1610, Investigation into Qualifying Facility Contracting and Pricing, Opening Testimony (solar issue)
Docket No. UM 1653, Idaho Power, Staff Evaluation of the Demand Response Programs, Testimony in Support of Settlement
Docket No. UM 1689, PacifiCorp, Prudence Determination Associated with the Energy Imbalance Market., Opening Testimony
Docket No. UM 1802, PacifiCorp, Investigation to Examine PacifiCorp's Non-Standard Avoided Cost Pricing, Response Testimony
Docket No. UM 1802, PacifiCorp, Investigation to Examine PacifiCorp's Non-Standard Avoided Cost Pricing, Reply Testimony
Docket No. UM 1802, PacifiCorp, Investigation to Examine PacifiCorp's Non-Standard Avoided Cost Pricing, Cross-response Testimony
Docket No. UM 1910, PacifiCorp, Resource Value of Solar,
Docket No. UM 1911, Idaho Power, Resource Value of Solar,
Docket No. UM 1912, Portland General Electric, Resource Value of Solar,
Docket No. UW 151, Charbonneau Water Co., Request for a General Rate Revision, Testimony in Support of Stipulation
Docket No. UW 152, Air Acres Water System, Request for a General Rate Revision, Testimony

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

Docket No. UM 2032

In the matter of

PUBLIC UTILITY COMMISSION OF OREGON,

Investigation into the Treatment of Network Upgrade Costs for Qualifying Facilities

RESPONSE TESTIMONY OF DAVID BUNGE

October 30, 2020

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is David Bunge. I am the President of Azimuth Renewables. My business address is 4220 Duncan, Suite 201, St. Louis, MO 63110.

Q. Please describe your background and experience.

A. My full biography is attached as NewSun/301. I have been actively developing utility-scale solar projects throughout the United States since 2007 including in North Carolina, South Carolina, Indiana, Montana, Michigan, and Oregon. During that time, I have been directly involved in the deployment of over 1,000 MW of new operational solar resources, in addition to thousand of MW more of development of solar generation beyond that.

These projects have included both qualifying facilities (QF) contracting under state Public Utility Regulatory Policies Act (PURPA) regulations, and bilaterally negotiated projects. I have been actively involved in navigating a wide array of interconnection studies, policies, procedures, and implementation, governed by utility policy, state and federal guidelines and RTO protocols, as part of direct development of projects, as well as transactions and due diligence related to the actual and prospective acquisition and sales and financing of facilities and development assets.

Q. On whose behalf are you appearing in this proceeding?

A. I am testifying on behalf of NewSun Energy LLC.

Q. Please summarize your testimony.

A.

II. TESTIMONY

Q. When were you involved in project development in Oregon?

A. From 2014-2019, I was actively involved in the development and contracting of several QF projects located throughout Oregon, as part of my employment with Cypress Creek Renewables, a major national developer of solar projects, in particular QFs, around the country, which succeeded in the greenfield development, financing, and construction of roughly a dozen QF projects, both on the Portland General Electric and Pacificorp systems, in addition to development efforts of a number of QF projects that were not ultimately constructed, in particular due to issues related to this docket. These projects included both standard contract QFs with capacities of 10MWac or less and non-standard QFs 20MWac and above. In particular, on the Pacificorp system, the Ochoco Solar project (20 MW) and the Grass Butte Solar project (40 MW), each of which were submitted (due to having no other choice under Oregon rules) as NRIS interconnections on the Pacificorp 115 KV system in Prineville, Oregon, and which resulted in significant Network Upgrades requirements explicitly associated with NRIS service, and which other generators proposed on the same system as ERIS did not have.

Q. This docket concerns the cost responsibility for network upgrades. Can you describe your experience with network upgrades in Oregon and elsewhere?

A. Yes. The projects I worked on faced many of the challenges typical to solar development. One challenge that proved unique to Oregon, however, was the requirement effectively imposed via the state-jurisdictional interconnection process, which *only* allows interconnection as NRIS (including how, in particular, Pacificorp implements their NRIS studies), for QF projects to deliver power to *load* rather than just a point on their system (i.e. a point of interconnection). In other states where I have developed projects, the QF's obligation is merely to deliver power to the Point of Interconnection (POI). Delivery of the power beyond the POI is the utility's responsibility. In states such as North Carolina, South Carolina, Indiana, Montana and Michigan, the question of whether the utility can support a new QF resource at a given location was not an operational calculation based on load in a given part of the utility's network, rather the calculation was based on the technical constraints of the physical infrastructure in the area (i.e. does the line or substation for the proposed POI have a sufficient MVA rating to support the project capacity and related reliability and communications issues).

In Oregon, questions around these delivery obligations and resource designations not only created severe confusion for developers and investors working to deploy solar QFs, but often impenetrable obstacles (including for facilities where an ERIS interconnection alternative would have posed no barrier) and ultimately proved to be a substantial barrier to new solar QF deployment in the state, and prevention of our ability in multiple cases from the ability to secure power sales of QFs that (based on our substantial experience and success delivering such projects successfully, including in Oregon) to be able to sell power under the PURPA mandatory purchase obligation. For example, I worked on multiple non-standard contract QF projects in PacifiCorp's Oregon service territory, above 10 MWac, particularly those listed above, that faced substantial barriers due to PacifiCorp's (and the state's) insistence that they be studied as network resources rather than an energy resources, which resulted in Pacificorp studies requiring the construction of (otherwise unnecessary for ERIS service) multi-hundred million dollar network upgrades for massive new transmission projects to achieve NRIS service.

(This was particularly concerning given other nearby similarly sized (or larger) ERIS solar projects having only smaller, multi-million dollar direct interconnection costs, some of which secured PPAs from PPA in the vicinity (on the same local 115 KV system) to sell power to Pacificorp, which in those cases Pacificorp, despite them being comparable and still eligible to be certificed as QFs, did not require to be NRIS in order to purchase power from them and (evidently) use that power for Pacificorp load. Ultimately, these issues proved to be substantial barriers, despite extensive efforts on the part of myself and my team, to sell as QFs to Pacificorp,. Functionally, they were forced to convert to ERIS interconnections, absent which there was no viable path, given that the identified upgrades that Pacificorp superimposed on the NRIS track were unviable from both a timeline and cost perspective, being essentially unbuildable and uninvestable. In my experience, these projects would have been successful at that time and likely operating by now if not for this NRIS requirement for QFs in Oregon. Functionally, the Oregon requirements for QFs to obtain restrictive network resource designation, an obligation to deliver to load rather than a POI, and uneconomic non-reimbursable transmission upgrades essentially created a not only cap on QF deployment, but a fatal barrier to related efforts, unfortunately a barrier which did not exist for comparable nearby facilities, whose studies did not include major decade-long new transmission construction projects for similarly sized and situated facilities. In short, this overall environment effectively this curtailed our business's ability to continue developing QF projects in Oregon relative to what generally would have likely been viable projects without the NRIS issue.

Q. Do you have any recommendations for changes the Oregon Commission can make to further encourage the deployment of renewable energy resources in the state?

Yes. If Oregon wishes to encourage renewable resource development in the state, it must align its interconnection practices with other states, which require QFs only to assure delivery to the purchasing utility, primarily by (1) ending the NRIS-only policy for state jurisdictional QFs and providing meaningful means for them to solar under ERIS interconnections, and (2) providing for refundability or utility-direct funding of network upgrades where possible, so that the utility ultimately pays for all network upgrades applicable to interconnecting a generator, as is the widely applicable practice. Oregon should similarly avoid other unduly burdensome for QF projects and create a climate of clarity and financeability. Solar and other renewable resources are generally economic under Oregon avoided cost rates and QFs therefore should be an important element in meeting Oregon's goals for decarbonization of the grid and reduction of greenhouse gases. But Oregon's convoluted interconnection rules create a serious barrier to QF development. Hence, if Oregon wants to encourage renewable energy development in the state, it must address these rules and align them with the rules of other states and with federal rules. Specifically, to the extent that QFs are assigned cost responsibility for network upgrades, Oregon should align itself with federal practice, which is to require refunds of the interconnection customer's network upgrade costs with interest in the form of cash or transmission credits. Similarly, Oregon should require QFs to deliver power to the point of interconnection with the purchasing utility, but should not force QFs to assume the utility's obligation for ultimate delivery of that power. Without these reforms, QFs will continued to be saddled with costs that they do not face in any other state and do not bear if they use FERC-jurisdictional transmission. Finally, I would also recommend that Oregon extend its PPA fixed price term lengths available to QFs to something commensurate with industry norms, ideally 25 year fixed price terms.

III. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.

David Bunge
President

Azimuth Renewables is led by David Bunge. He has been active in developing utility-scale solar projects since 2007. David has directly developed over 100MW of utility-scale solar projects throughout the United States. Many of these projects have been some of the first utility-scale projects deployed in markets such as Oregon, Missouri and Indiana. David has successfully negotiated PPAs with utilities across the country including Duke Energy, Pacificorp, Dominion (formerly South Carolina Gas & Electric), and Intermountain Rural Electric.

Prior to joining Azimuth Renewables, David served as Vice President of Strategic Development for Cypress Creek Renewables (CCR) from 2014-2019. In this role, David was instrumental in CCRs deployment of over 1.5GW of solar. David has also managed his own development company and served in senior leadership roles throughout the solar industry.

David has extensive business development experience in the solar industry and holds an MBA from NC State University and a B.A. in History from Davidson College.

Representative Project Experience:

- Bowman, 105 MW, SC
- Palmetto Solar, 105 MW, SC
- Buckleberry Solar 70MW, NC
- Bullock Solar 70MW, NC
- Nixa Solar, 11 MW, MO
- Pastime Solar, 7 MW, IN
- McDonald Solar, 7MW IN
- Auten Road, 7 MW, NC
- Neff Solar, 14MW, OR
- Collier Solar, 14MW, OR