

**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

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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

1 positions including Manager of Market Operations and Director of the Project
2 Management Office. I began my career at Pacific Gas and Electric in 1991 where I
3 worked as a staff level engineer in the bulk transmission operations group, hydro-electric
4 generation, and distribution planning.

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

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

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

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

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

1 Courthouse South; and, (4) *California Solar Ranch v. Area Energy* (JAMS ref. No
2 1100088728), an arbitration proceeding. Prior to the past 4 years, I represented the
3 CAISO as an expert on matters related to system voltages and reliability issues in a case
4 presided over by an Administrative Law Judge¹.

5 Additionally, during my time at the CAISO, I provided written testimony to the
6 Federal Energy Regulatory Commission (FERC) related to market rules and
7 functionality. I provided written testimony to FERC on 3 occasions which included
8 comments related to the re-design of the CAISO markets under the Market Re-Design
9 and Technology Upgrade (MRTU) project², development of Business Practice Manuals
10 for MRTU³, and Long-Term transmission rights in organized markets⁴.

11 **Q. Please summarize your testimony.**

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

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

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

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

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

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

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

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

18 **II. ISSUE 1: COST RESPONSIBILITY FOR NETWORK UPGRADES**

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

21 **A.** When a prospective generator proposes to be interconnected to the grid, there is an
22 interconnection study process which the applicable transmission owner goes through in
23 order to evaluate the ability of the grid to interconnect the facility to the grid, including

1 the capacity of the system to support the generator, impacts the generators would have,
2 and what new system features, safety and reliability measures, generator metering and
3 communication requirements, as well as downstream upgrades might be necessary, to
4 meet minimum applicable reliability and other standards for the grid should the generator
5 be built. These studies generally happen through a sequence of three primary studies: a
6 feasibility study (sometimes optional), a system impact study (“SIS”), and a facilities
7 study (“FAS”), which sequentially look in greater detail at the impacts of the facility to
8 the system.

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

14 **1) “*Interconnection Facilities*”** are those facilities (and costs) strictly associated with
15 interconnecting the project-specific generator itself reliably *to* the existing host
16 transmission system. The associated facilities (and costs) are also called “Direct
17 Assign” facilities (and costs), meaning that they are only needed due to the physical
18 interconnection of the generator and the generator is the sole reason these facilities
19 are needed. Direct Assignment facilities (and costs) for interconnection, for example,
20 include items such as the interconnection substation elements needed to terminate the
21 generator’s tieline and looping in and out of the existing utility transmission line, or
22 to connect the generation facility’s customer-owned substation to the utility-owned
23 grid. Direct Assigned Interconnection Facilities may also commonly include the

1 addition of protection devices (i.e. protective relays) at substation remote from the
2 point of interconnection that are solely needed for coordinating line protection with
3 the new interconnection substation. Direct Assignment facilities cost are entirely the
4 responsibility of the generator developer as they do not provide benefits to others.
5 Direct Assign interconnection facilities *do not include* “downstream” impacts to the
6 system which must be upgraded to support the generator, but which also benefit the
7 grid more broadly than the specific project, which are generally called network
8 upgrades, as described further below.

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

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

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

20 **Reliability Upgrades** are those upgrades needed to meet basic NERC/WECC
21 reliability standards. They are most often associated with elements such as short circuit
22 ratings of existing substation equipment such as breakers and switches, and typically very
23 local to the interconnection site location. Other Reliability Upgrades may include

1 expansion of substation buses and installation of special protection schemes. In general,
2 RU are required to ensure the bulk electric grid is in compliance with North American
3 Electric Reliability Corporation (NERC) reliability standards and WECC reliability
4 criteria.

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

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

1 capacity, especially within the local area for both merchant generation as well as the host
2 utility.

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

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

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

22 **A.** Sure. First, the Joint Utilities describe Network Upgrades identified in an Energy
23 Resource Interconnection Service (ERIS) study that are primarily needed to safely and
24 reliably physically interconnect the generating resource to the utility’s transmission

1 system.⁵ Under an ERIS the Joint Utilities are describing Reliability Upgrades needed to
2 meet basic reliability criteria as I describe above and do not include local or area
3 deliverability network upgrades. This would be consistent with my understanding of an
4 ERIS and the types of “network upgrades” that an ERIS interconnection study would
5 identify. An ERIS, by definition, allows for the use of existing firm capacity, which
6 would not include any local or area capacity increases.

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

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

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

⁵ Joint Utilities/100, Vail-Bremer-Foster-Larson-Ellsworth/8.

⁶ Id.

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

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

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

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

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

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

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

10

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

11

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

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

7 **III. ISSUE 2: INTERCONNECTION SERVICE AVAILABLE TO QFS**

8 **Q. Please define ERIS and NRIS.**

9 **A.** Energy Resource Interconnection Service (ERIS) is defined as “an Interconnection
10 Service that allows the Interconnection Customer to connect its Generating Facility to the
11 Transmission Providers Transmission System to be eligible to deliver the Generating
12 Facility’s electric output using the existing firm or nonfarm capacity on the Transmission
13 Providers Transmission System on an as available basis”.

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

19 **Q. When is each interconnection service type typically used?**

20 **A.** ERIS is used by generators that can operate and deliver energy utilizing the existing
21 system capacity on an as-available basis. The decision to go with ERIS as opposed to
22 NRIS is generally a decision left to the generator based on many factors including: cost
23 of the network upgrade, risk of curtailment, power purchase agreement provision, and

1 ability for the generator in general to remain economically viable. In the case of
2 renewable generation such as solar, ERIS is often found to be acceptable when economic
3 dispatch is considered. Under a least cost economic dispatch, constrained by system
4 capacities, solar will most often be the least cost during sunlight hours and be the primary
5 user of system capacity. Gas plants and non-renewable resources will most often be
6 needed in the early morning and evening hours when solar is not available.
7 Consequently, from a practical perspective, considering economic dispatch, ERIS can be
8 an acceptable arrangement for solar generation and avoid costly and possibly unnecessary
9 network upgrades.

10 NRIS is used by generators that require dedicated firm system capacity to satisfy
11 a power purchase agreement or otherwise require or desire firm capacity to avoid
12 curtailments and financial deficiencies. In most cases the need to be “deliverable” via
13 firm system capacity also comes with added benefit in terms of energy value. Without a
14 corresponding increase in energy value corresponding with the “firm” capacity associated
15 with a costly network upgrade, the generator may become un-economic and will certainly
16 be disadvantaged in terms of energy price needed to remain an economically viable
17 project. From my experience, working with generation interconnections across the
18 WECC, NRIS is most often used by generation that may be exporting from the area they
19 are interconnected with to a neighboring area and selling a firm or “deliverable” energy
20 product, or they have a contract obligation imposed by the buyer that requires firm
21 transmission service for deliveries within the host utility area. It is decidedly less
22 common, unless perhaps a study that looks at ERIS *and* NRIS, as is sometimes requested

1 by interconnection customers, shows no additional cost for the NRIS due to not requiring
2 upgrades to achieve NRIS.

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

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

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

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

15 **A.** First, shifting the network upgrade cost to the generator, puts an unnecessary financial
16 burden on the generator, and will result in higher overall project costs for energy
17 produced by the specific generator burdened with the additional cost, with commensurate
18 implications for project economics and project viability. These costs are further
19 amplified by the fact that interconnection costs—whether direct assign or network
20 upgrades—are not eligible for tax credits, meaning their impact is effectively a multiple
21 of the costs. So additional costs, especially if not needed for the delivery of the power to
22 the utility, burden and might kill the project's viability. This is true in the case that such
23 costs are small, proportionally, but even more in the case that unnecessary large costs are

1 added. There is also an issue from the perspective of the developer being required to post
2 such costs, especially when large, before a PPA is secured, in terms of the risk profile (or
3 even impossibility) of posting them before a viable off-take agreement is secured.

4 Oregon's approach is thus unnecessarily burdensome on the generator developer and
5 ultimately would be harmful to a QF and discriminatory to a QF generator as compared
6 to substantially identical generator (i.e. same size and technology) that would
7 interconnect, and be allowed to sell power, as is common, as an ERIS.

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

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

19 NRIS, by definition, provides for the generator to be integrated within the
20 transmission system similar to how the utility would integrate its own generation to serve
21 native load. However, imposing NRIS on QF generation, may result in unnecessary
22 system upgrades. For example, a solar resource may be acceptable of ERIS given their
23 specific business plan and delivery requirements. However, if NRIS is imposed, the host

1 utility may find a need, under conservative study assumptions, that at times there may be
2 insufficient demand in the local area and consequently the need for upgraded or entirely
3 new capacity. Unless the situation results in a violation of NERC/WECC reliability
4 standards that require a RU, the generator should be offered the option of ERIS or NRIS.

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

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

18 California is obviously unique in that it has experienced a massive influx of solar
19 generation over the past 10 years which has largely consumed available system capacity.
20 Consequently, the costs for full deliverable status (i.e. NRIS) has significantly increased
21 to the point *that nearly all generators select to go with ERIS type interconnection*. In
22 fact, the CAISO has implemented a step in their process where generators specify if they
23 are willing to fund NRIS type upgrades or go with ERIS. This process step has been

1 going on for roughly the past 5 years, and to date it is my understanding that NRIS has
2 never been selected by a generator due to the treatment of the associated network
3 upgrades.

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

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

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

21 **IV. CONCLUSION**

22 **Q. Do you have any concluding remarks?**

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

16 **Q.** **Does this conclude your testimony?**

17 **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

1 I. INTRODUCTION

2 Q. Please state your name and occupation.

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

5 Q. Please describe your background and experience.

6 A. I was employed as a Utility Analyst on the Staff of the Oregon Public Utility
7 Commission (OPUC or Commission) for eight years, from 2011 to 2019, during which
8 time I provided analysis, testimony, and recommendations to the Commission on water,
9 natural gas and electric regulatory filings. From 2013 through the majority of 2019, as
10 Senior Utility Analyst, I was the principal Staff on OPUC cases involving Public Utility
11 Regulatory Policies Act (“PURPA”) policies and regulations in Oregon, including
12 general policy investigations and utility-specific dockets.¹ Specific to qualifying facility
13 (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 Pricing*, 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).

1 Commission in 2019, resulting in the posting of information about each utility's
2 distribution system on its Open Access Same-time Information System (OASIS).²

3 Prior to the Commission, I worked as Public Utilities Specialist for Bonneville Power
4 Administration from 1992 to 2009 in a variety of functional areas, including long-term
5 power sales forecasting, contracting, rates and product analysis, meter data management,
6 and in power operations scheduling and short-term forecasting. Please see my attached
7 witness qualification statement attached as NewSun/201.

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

9 **A.** I am testifying on behalf of NewSun Energy.

10 **Q. Please summarize your testimony.**

11 **A.** My testimony responds to the Joint Utilities' Direct Testimony and in response to the two
12 questions in the scope of this phase of this investigation³:

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

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

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).

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

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

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

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

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.

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

11 Because many QFs are small generator facilities with a nameplate capacity of
12 10 MW or less, any changes to the cost allocation policy logically would apply to any QF
13 interconnection, regardless of whether it is considered "large" or "small."

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

15 **A.** No. Large generator interconnection was addressed in Docket No. UM 1401. That
16 docket was opened as a result of a Staff Report precipitated by Docket No. AR 526, a
17 rulemaking to update Division 029 due to 2007 legislative changes and Commission
18 Order No. 07-360 in Docket UM 1129.⁶ The Staff report requested that the Commission
19 open an investigation into interconnection of PURPA QFs with a nameplate capacity

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>.

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

3 At staff's AR 526 workshop on August 7, 2008, the utilities and other
4 stakeholders supported the concept of using FERC's small generator
5 interconnection agreements for QFs between 10 MW and 20 MW, and
6 FERC's large generator interconnections and agreements for QFs over 20
7 MW, until the Commission establishes interconnection rules for these
8 generators.

9 Originally, staff believed the Commission could adopt these procedures and
10 agreements in AR 529. However, after consulting with the Hearings
11 Division, staff's attorney advises that the Commission should instead do so
12 through an investigation. The investigation will allow the utilities to
13 slightly modify their FERC-approved filings as necessary to make them fit
14 within Oregon's regulatory scheme. For example, the utilities may specify
15 that the small generator procedures and agreements are available to QFs
16 over 10 MW (smaller QFs will be subject to the Commission's order in AR
17 521), change references such as "FERC" to "PUC" and "Transmission
18 Provider" to "public utility," specify that the Commission's dispute
19 resolution procedures will be used instead of FERC's, and confirm the
20 FERC interconnection procedures and agreements to the Commission's
21 decisions in AR 521 as necessary. However, staff does not expect the
22 utilities to change the FERC-approved procedures and agreements in any
23 material way.

24 Staff recommends each utility file its draft modifications to the FERC-
25 approved procedures and agreements no later than 120 days of granting
26 staff's motion to open the investigation. The filing should include redline
27 versions showing all changes made to the FERC-approved documents as
28 well as an explanation of the proposed modifications.⁸

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

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.

1 references to interconnection of QFs but “do not provide uniform technical standards or
2 uniform procedures and terms for interconnection agreements.”⁹

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

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

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

12 **A.** Not to my knowledge.

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

15 **A.** Joint Utilities state that “the Oregon Commission directed transmission providers to
16 eliminate Section 11.4.1 of FERC’s pro forma LGIA from the Oregon QF-LGIA. Section
17 11.4.1 is the provision that entitles an interconnection customer to be reimbursed for the
18 cost of its Network Upgrades through payment of transmission credits over time.”¹¹
19 They then cite the Commission’s rationale for rejecting FERC’s interconnection cost
20 allocation policy as stated in Order No. 10-132.

21 **Q. Do you agree with Joint Utilities’ characterization of the Commission’s direction?**

⁹ *Id.* at 2.

¹⁰ Docket No. UM 1401, Ruling (Feb. 12, 2009).

¹¹ Joint Utilities/100, Vail-Bremer-Foster-Larson-Ellsworth/24.

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

4 **Q. Please describe the intervening actions.**

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

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

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

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).

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

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

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

36 **Q. What followed the March 2009 utility filings?**

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).

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

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

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

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>.

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

4 **Q. How did the Commission resolve this issue?**

5 **A.** Order No. 10-132 states:

6 As noted by the Utilities, transmission costs and network upgrades are
7 included in the calculation of avoided cost rates. Consequently, QFs are
8 currently compensated for these costs pursuant to the rates established in
9 their respective purchased power agreements with the utilities. For this
10 reason, we conclude that Article 11.4 should be modified such that
11 Interconnection Customers are responsible for all costs associated with
12 network upgrades unless they can establish quantifiable system-wide
13 benefits, at which point the Interconnection Customer would be eligible for
14 direct payments from the Transmission Provider in the amount of the
15 benefit.

16 We are not persuaded by ICNU’s arguments that requiring Transmission
17 Providers to pay for network upgrades would not affect the avoided cost
18 rate and thus impose higher costs on the ultimate ratepayer. ICNU’s reliance
19 on the reimbursement provisions set forth in the CA-LGIA is misplaced, as
20 the CA-LGIA is a FERC tariff that is not bound by the limitations imposed
21 by PURPA. Moreover, ICNU’s argument that FERC has long held that
22 Network Upgrades provide system wide benefits is not persuasive to this
23 point. None of the authorities cited are related to facilities governed by
24 PURPA and thus none faced the limitation of the avoided cost rate.¹⁸

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

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

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).

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

2 Under the Federal Energy Regulatory Commission’s rules governing small
3 generator interconnection, there is a process for sharing the cost of system
4 upgrades among small generator facilities using transmission credits. ICNU
5 argues that a similar process should be included in our small generator
6 interconnection rules to ensure that one small generator facility does not pay
7 the entire cost of system upgrades that primarily benefit the public utility or
8 other small generators. ICNU also fears that a public utility might require a
9 small generator to pay for system upgrades that the utility planned to make
10 with or without the small generator’s interconnection.

11 Because not all small generator facilities under this Commission’s
12 jurisdiction will be using a public utility’s transmission system, a process
13 allowing cost sharing of system upgrades using transmission credits is not
14 feasible. The participants in the rulemaking process were unable to find
15 another method of sharing such costs. The proposed rules, however, include
16 language that is meant to strictly limit a public utility’s ability to require one
17 small generator facility to pay for the cost of system upgrades that primarily
18 benefit the utility or other small generator facilities, or that the public utility
19 planned to make regardless of the small generator interconnection. Under
20 the proposed rules, a public utility may only require a small generator
21 facility to pay for system upgrades that are “necessitated by the
22 interconnection of a small generator facility” and “required to mitigate” any
23 adverse system impacts “caused” by the interconnection. We therefore
24 believe the proposed rules adequately protect small generator facilities and
25 that ICNU’s fears are unfounded.¹⁹

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

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

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

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

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

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

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

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

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

1 removing this information from the Interconnection Request. This should
2 address the concerns of most commenters.

3 In response to National Grid, we note that the LGIA's more expansive
4 Network Resource Interconnection Service is intended to give the
5 Interconnection Customer broad access to the backbone of the Transmission
6 Provider's Transmission System. In essence, it allows the generating facility
7 to pre-qualify as a Network Resource for any Network Customer on the
8 Transmission System and, as National Grid notes, may make it eligible for
9 installed capacity credits. Because Network Resource Interconnection
10 Service entails high technical standards, we expect that an Interconnection
11 Customer, particularly one interconnecting at a lower voltage, would rarely
12 find this service to be efficient or practical. Nevertheless, we do not want to
13 preclude it from choosing this option. If it wishes to interconnect its Small
14 Generating Facility using Network Resource Interconnection Service, it
15 may do so. However, it must request interconnection under the LGIP and
16 execute the LGIA.²⁰

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

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

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).

1 It adopted this proposal in Order No. 792.²² As the Commission’s explanation makes
2 clear, NRIS is used for small generators only if the small generator elects to use it for economic
3 reasons.

4 **Q. The Joint Utilities refer to “fragmented rules and policies applicable to generators
5 of various sizes.”²³ Based on your experience with Oregon’s implementation of
6 PURPA as it pertains to interconnection, do you agree with this description?**

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

15 **III. NEGATIVE IMPACTS OF OREGON’S QF NETWORK UPGRADE COST
16 ALLOCATION POLICIES**

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

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

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).

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

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

14 **Q. What about the cost causation principle?**

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

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

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

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

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

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

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

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

19 **A.** Yes. The prospect of prohibitively high system upgrade costs, as well as other
20 interconnection costs, has been a major issue in Docket No. UM 1930, Community Solar
21 Program (CSP) Implementation. CSP projects are sized at 3 MW or lower. In that
22 docket, stakeholders expressed concerns that interconnection costs may prevent

1 successful launch of the CSP.²⁶ After a significant amount of discussion among the many
2 stakeholders, Staff and the utilities, the Commission adopted the Staff recommendation
3 for a “Simplified CSP interconnection process.”²⁷

4 IV. OREGON’S CLIMATE GOALS AND RENEWABLE ENERGY

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

7 **A.** On March 10, 2020, Oregon Governor Kate Brown issued Executive Order 20-04,
8 establishing GHG Emissions Reduction Goals. The Order calls for Oregon to reduce its
9 GHG emissions (1) at least 45 percent below 1990 levels by 2035; and (2) at least 80
10 percent below 1990 levels by 2050.²⁸ This Order also directs agencies to “exercise any
11 and all authority and discretion vested in them by law to help facilitate Oregon’s
12 achievement of the GHG emissions reduction goals set forth in . . . this Executive
13 Order.”²⁹

14 In 2016, the passage of Senate Bill 1547 amended Oregon’s Renewable Portfolio
15 Standard (RPS), requiring 50 percent of the electricity that is used in the state to come
16 from renewable resources and the removal of coal from the state’s electricity supply by
17 2040. I perceive Oregon as a leader in climate and renewable energy initiatives and
18 believe it is reasonable to expect that Oregon will continue to pursue initiatives that

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.*

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

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

6 **A.** Yes, absolutely.

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

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

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

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

19 **V. RECOMMENDED CHANGES TO INTERCONNECTION SYSTEM**
20 **UPGRADE COST ALLOCATION POLICIES**

21
22 **Q. What changes do you recommend to the current rules and policies?**

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

1 **Q. What about the “customer indifference” standard?**

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

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

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

³⁰ Joint Utilities/200, Wilding-Macfarlane-Williams/5-6.

³¹ Order No. 10-132 at 3.

1 **Q. Please explain.**

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

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

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.”).

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

10 VI. CONCLUSION

11 **Q. Does this conclude your testimony?**

12 **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

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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

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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.

1 **II. TESTIMONY**

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

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

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

19 **A.** Yes. The projects I worked on faced many of the challenges typical to solar
20 development. One challenge that proved unique to Oregon, however, was the requirement
21 effectively imposed via the state-jurisdictional interconnection process, which *only*
22 allows interconnection as NRIS (including how, in particular, Pacificorp implements their
23 NRIS studies), for QF projects to deliver power to *load* rather than just a point on their

1 system (i.e. a point of interconnection). In other states where I have developed projects,
2 the QF's obligation is merely to deliver power to the Point of Interconnection (POI).
3 Delivery of the power beyond the POI is the utility's responsibility. In states such as
4 North Carolina, South Carolina, Indiana, Montana and Michigan, the question of whether
5 the utility can support a new QF resource at a given location was not an operational
6 calculation based on load in a given part of the utility's network, rather the calculation
7 was based on the technical constraints of the physical infrastructure in the area (i.e. does
8 the line or substation for the proposed POI have a sufficient MVA rating to support the
9 project capacity and related reliability and communications issues).

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

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

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

3 Yes. If Oregon wishes to encourage renewable resource development in the state, it must
4 align its interconnection practices with other states, which require QFs only to assure
5 delivery to the purchasing utility, primarily by (1) ending the NRIS-only policy for state
6 jurisdictional QFs and providing meaningful means for them to solar under ERIS
7 interconnections, and (2) providing for refundability or utility-direct funding of network
8 upgrades where possible, so that the utility ultimately pays for all network upgrades
9 applicable to interconnecting a generator, as is the widely applicable practice. Oregon
10 should similarly avoid other unduly burdensome for QF projects and create a climate of
11 clarity and financeability. Solar and other renewable resources are generally economic
12 under Oregon avoided cost rates and QFs therefore should be an important element in
13 meeting Oregon's goals for decarbonization of the grid and reduction of greenhouse
14 gases. But Oregon's convoluted interconnection rules create a serious barrier to QF
15 development. Hence, if Oregon wants to encourage renewable energy development in
16 the state, it must address these rules and align them with the rules of other states and with
17 federal rules. Specifically, to the extent that QFs are assigned cost responsibility for
18 network upgrades, Oregon should align itself with federal practice, which is to require
19 refunds of the interconnection customer's network upgrade costs with interest in the form
20 of cash or transmission credits. Similarly, Oregon should require QFs to deliver power to
21 the point of interconnection with the purchasing utility, but should not force QFs to
22 assume the utility's obligation for ultimate delivery of that power. Without these
23 reforms, QFs will continued to be saddled with costs that they do not face in any other

1 state and do not bear if they use FERC-jurisdictional transmission. Finally, I would also
2 recommend that Oregon extend its PPA fixed price term lengths available to QFs to
3 something commensurate with industry norms, ideally 25 year fixed price terms.

4 **III. CONCLUSION**

5 **Q. Does this conclude your testimony?**

6 **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