PACIFIC POWER
A DIVISION OF PACIFICORP

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July 24, 2015

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
201 High Street SE, Suite 100
Salem, OR 97301-1166

Attn: Filing Center

RE: UM 1610 Phase II—PacifiCorp's Response Testimony

PacifiCorp d/b/a Pacific Power encloses for filing its Response Testimony in the above-referenced docket.

If you have questions about this filing, please contact Erin Apperson, Manager Regulatory Affairs, at (503) 813-6642.

Sincerely,

R. Bryce Dalley/esn

R. Bryce Dalley
Vice President, Regulation

Enclosure

Docket No. UM-1610
Exhibit PAC/1100
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Response Testimony of Brian S. Dickman

July 2015

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Q. Are you the same Brian S. Dickman who previously submitted direct testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or Company)?

A. Yes.

Q. What is the purpose of your response testimony?

A. The purpose of my testimony is to respond to the direct testimony filed by intervening parties in Phase II of this docket. I respond to arguments pertaining to issues 2, 3, 4, 6, and 7 raised by Bill Eddie on behalf of OneEnergy, Inc. (OneEnergy); Philip Carver and Diane Broad on behalf of the Oregon Department of Energy (ODOE); John Lowe on behalf of the Renewable Energy Coalition (REC); Brian Skeahan on behalf of Community Renewable Energy Association (CREA); Brittany Andrus on behalf of the Public Utility Commission of Oregon staff (Staff); and Kevin Higgins on behalf of REC, CREA, OneEnergy, and Obsidian Renewables, LLC (Joint QF Parties). Specifically my testimony supports the following:

- The Commission should clarify whether transmission system upgrades which are specifically attributable to the proxy resource and which can be avoided by the addition of a QF should be reflected in avoided costs. Regardless of that policy decision, the Company's Energy Gateway transmission project is not a transmission upgrade tied to a specific proxy resource and is not a transmission resource that will be avoided by the addition of QFs in Oregon.
- The solar capacity adder approved by the Commission in Order No. 14-058 is adequate and does not need to be corrected. Adopting the proposed changes

to the standard renewable and non-renewable avoided costs calculations will overstate avoided costs.

- The proposal to pay QFs capacity during the sufficiency period equal to the cost of required environmental upgrades at existing coal plants is fundamentally flawed and does not represent costs that can be avoided by the addition of Oregon QFs on PacifiCorp's system.
- Using the preferred portfolio from the IRP is adequate and appropriate to determine the sufficiency period for standard avoided costs. If the preferred portfolio was updated it would likely lengthen the sufficiency period.
- Renewing QFs should not automatically receive capacity payments during the sufficiency period when a contract is renewed; this is the equivalent of extending the contract term beyond 20 years.
- Using the GRID model for non-standard prices results in the most accurate calculation of PacifiCorp's avoided costs and is not unduly complicated, especially for experienced and commercially sophisticated developers of large QF projects.

ISSUE 2: SHOULD AVOIDED TRANSMISSION COSTS FOR NON-RENEWABLE AND RENEWABLE PROXY RESOURCES BE INCLUDED IN THE CALCULATION OF AVOIDED COSTS?

Q. Please summarize OneEnergy's position.

A. OneEnergy maintains that avoided transmission costs for the non-renewable and renewable proxy resources should be included in the calculation of avoided costs, even if the proxy resource is located on the Company's system. Specifically, OneEnergy recommends the Commission apply the following test: if the on-system proxy resource cannot be designated a Network Resource at its full capacity without transmission upgrades and without de-rating or curtailing other Network Resources, then the cost of transmission upgrades necessary to make it a Network Resource should be included in avoided cost prices.[1] Similar to OneEnergy, CREA recommends the Commission clarify its statement in Order No. 14-058 such that a proxy resource must be able to serve load as a Network Resource without transmission upgrades in order for there to be no avoided transmission costs.[2]

Q. Does OneEnergy take issue with specific transmission costs in the Company's Integrated Resource Plan (IRP)?

A. Yes. OneEnergy refers to the Company's 2013 IRP and the Wyoming wind in the "Aeolus wind bubble" as a specific example of a renewable proxy resource that will require additional transmission to carry the generation to load.[3] In this example, OneEnergy identifies the transmission constraints that exist in this geographical area and notes that the Gateway West transmission project will facilitate delivery of the energy from the proxy resource. OneEnergy implies that the entire cost of the Gateway West project should be included in the standard renewable avoided costs that rely on the Wyoming wind proxy.

Q. Does the Company agree that cost of Gateway West should be included in avoided costs?

A. No.

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[1] OneEnergy/400, Eddie/3.
[2] CREA/500, Skeahan/12.
[3] OneEnergy/400, Eddie/3-4.

Q. Why should the Gateway West transmission project be excluded from avoided costs?

A. Completion of the Gateway West transmission project is not directly tied to the proxy renewable resource and will not be avoided due to the addition of renewable QFs in Oregon. OneEnergy is correct that transmission constraints exist in the bubble where the proxy resource is planned; however, the constraints exist regardless of whether the proxy resource is built or not. The purpose of the Gateway West transmission project is to alleviate existing transmission constraints and improve the ability to deliver energy from all existing resources to load. Additionally, Gateway West's planned in service date assumed in the 2013 IRP was more than five years before the proxy resource's in-service date. In short, the proxy resource does not create the need for Gateway West.

Q. Are there any other reasons why the Gateway West transmission project is planned?

A. Yes. The 2015 IRP states "the Gateway West project would enable the Company to more efficiently dispatch system resources, improve performance of the transmission system (i.e. reduced line losses), improve reliability, and enable access to a diverse range of new resource alternatives over the long-term."[4]

Q. Does OneEnergy propose an alternative to including Gateway West in avoided costs?

A. Yes. OneEnergy suggests that a different proxy resource be used if the Gateway West transmission project is not included in avoided costs. However, hypothetically altering the resource portfolio as suggested by OneEnergy departs from the least-cost

[4] PacifiCorp 2015 IRP, Vol. I, p. 50 – 51.

least-risk plan as determined by the IRP and would artificially increase avoided costs to the detriment of retail customers.

Q. Does the Company include in its IRP specific costs for transmission system upgrades required to integrate generation resources in the preferred portfolio?

A. Yes. Table 6.22 in the 2013 IRP provides the costs associated with transmission upgrades required to interconnect supply-side resources.

Q. CREA argues that "the cost of *any* transmission to move power from *any* proxy resource to the utility's load must be included in avoided cost rates."[5] (Original emphasis) Do you agree?

A. No. Avoided costs should not include assumed reductions in transmission service costs or third-party wheeling expenses due to the addition of a QF on PacifiCorp's system. Planned resource acquisitions included in the Company's IRP are sited within PacifiCorp's service territory and do not require third-party transmission service to reach the Company's system. As described in my Phase 2 direct testimony, PacifiCorp operates its resources as a multi-state system and a portion of Company resources located all across the Company's service territory are allocated to Oregon customers. The Company utilizes its transmission rights to serve customers and optimize the dispatch of its system to the benefit of all retail customers. Company-owned transmission infrastructure and contractual rights on third-party systems are needed to operate PacifiCorp's system whether it adds QF or non-QF resources.

[5] CREA/500, Skeahan/12.

Q. Did any other party address the treatment of transmission system upgrades for avoided costs?

A. Yes. Staff recommends that the Commission clarify that third-party transmission costs and costs to build a transmission resource should be included in avoided costs if the purchase from a QF would actually allow the utility to avoid such costs.[6]

Q. Does the Company agree the Commission should clarify the treatment of transmission upgrades for on-system proxy resources?

A. Yes. All parties would benefit if the Commission clarified its intended treatment of transmission system upgrades. The Company does not object to including in avoided costs specific transmission system upgrades directly associated with the proxy resource as included in the IRP and which could be avoided by the addition of an Oregon QF. However, the Company strongly disagrees that the costs of the Gateway West transmission project should be included in avoided costs because they are not specifically linked to the renewable proxy resource and are not avoidable by the addition of QFs in Oregon.

ISSUE 3: SHOULD THE COMMISSION REVISE THE METHODOLOGY APPROVED IN ORDER NO. 14-058 FOR DETERMINING THE CAPACITY CONTRIBUTION ADDER FOR SOLAR QFS SELECTING STANDARD RENEWABLE AVOIDED COST PRICES? IF SO, HOW?

Q. Please summarize Staff's position concerning the solar capacity adder.

A. Staff's position is that the solar capacity adder approved by the Commission in Order No. 14-058 should be modified so a solar QF would receive a fixed payment for avoided capacity costs. Staff claims that spreading the fixed capacity costs over the proxy resource's on-peak generation results in an inadvertent "double discount" to the

[6] Staff/500, Andrus/10.

capacity costs and lower payments to a solar QF. ODOE and CREA support Staff's proposal. The Company has addressed the shortcomings of this argument in the direct and rebuttal testimony of Mr. Gregory N. Duvall.[7] The Parties' positions boil down to a proposal that the solar capacity adder should be determined as a fixed dollar amount equal to the cost of an avoided thermal resource and that each QF should receive the entire amount regardless of its actual output during on peak hours.

Q. Do you agree with Staff that solar QFs would be undercompensated for the value of capacity due to the payment structure approved by the Commission in Order No. 14-058?

A. No. Staff argues that if the capacity costs are spread over the on-peak generation of the avoided thermal resource, a solar QF will be undercompensated because it is expected to be available for fewer hours than the avoided resource. This is not an unintended consequence, but is a representation of the costs actually avoided by the Company. The main points of the Company's position, as filed in previous testimony, are summarized as follows:

- Avoided costs during the deficiency period are defined as the cost of a proxy resource and are intended to reflect the actual deferral or avoidance of that resource. Applying the adjustment to capacity contribution as approved by the Commission is an appropriate discount for intermittent resources, and does not "double discount" capacity costs for solar QFs.
- It is correct to base avoided costs on the characteristics of the resource that is being avoided, rather than on the characteristics of the QF. The fact that a

[7] Pac/600-Duvall and Pac/700-Duvall.

solar QF is available for fewer hours than the avoided resource compels a lower payment.

- The proxy thermal resource provides several benefits to the utility that are not provided by a solar QF, including the ability to dispatch the resource on an as-needed basis and the ability to provide operating reserve capacity. These benefits are available to the Company in all hours, not just when the resource is generating energy.

Q. Why are Staff's proposed changes flawed?

A. The standard renewable prices cannot be tailored to each unique QF, and Staff's proposal will still result in varying payments to QFs depending on their output. Both Staff's proposal and the current method rely on a $/MWh price for capacity; the only difference is that the capacity dollars are spread over a smaller number of on-peak hours, based on a typical solar resource as included in an IRP. If the actual output of a solar QF is different from the typical solar resource in the Company's IRP, the amount paid to the QF for capacity will vary. For example, if the typical solar resource had a 30 percent on-peak capacity factor, and an individual solar QF has an on-peak capacity factor of 35 percent, the QF will be overpaid and would exceed avoided costs if avoided capacity costs were applied consistent with Staff's recommendation.

Q. Does a gas plant, like the type used to determine the capacity cost during the deficiency period, provide value other than generation?

A. Yes. A gas plant provides value because it is dispatchable. The ability to generate or not generate in a given hour provides a benefit to customers in the form of decreased net power costs. For example, when market prices are less than the cost to generate the plant can be shut down and the Company can service its load more cost effectively. A gas plant can also hold reserves and integrate intermittent energy resources, which benefits customers by providing reliable and safe energy.

Q. Does Staff's proposal result in over paying capacity costs to solar QF's?

A. Yes. Under Staff's proposal a solar QF would receive payment for the entire value of the displaced capacity but the QF would provide generation only, essentially ignoring the value of the a gas plant provides in its ability to be dispatched, hold reserves, and integrate intermittent energy.

Q. Do you recommend any change to the solar capacity adder?

A. No. The issue before the Commission is whether, after adjusting the capacity contribution from 100 percent to 13.6 percent, a solar QF should get paid for capacity based on a target dollar amount, or if it should get paid for capacity only for the hours it generates during on-peak hours. The Commission should confirm the decision reached in Order No. 14-058 and should not adopt additional changes to the standard renewable avoided cost rates.

ISSUE 4: SHOULD THE CAPACITY CONTRIBUTION CALCULATION FOR STANDARD NON-RENEWABLE AVOIDED COST PRICES BE MODIFIED TO MIRROR ANY CHANGE TO THE SOLAR CAPACITY CONTRIBUTION CALCULATION USED TO CALCULATE THE STANDARD RENEWABLE AVOIDED COST PRICE?

Q. Please summarize Staff's position concerning the capacity contribution calculation for standard non-renewable avoided costs prices.

A. Staff believes the capacity contribution adjustment for standard non-renewable avoided costs prices should be modified so an intermittent QF would receive the entire value of capacity per MW year spread over on-peak generation.[8] In other words, Staff believes the capacity contribution calculation for standard non-renewable avoided cost prices should mirror the calculation used in standard renewable avoided cost prices.

Q. Is the issue of capacity contribution and the payment of capacity costs to a QF the same for the standard renewable and the standard non-renewable avoided costs?

A. Yes.

Q. Do you agree with Staff's position?

A. No. The Company recommends the Commission reject the proposal to modify the capacity contribution calculation for standard non-renewable avoided cost prices for the same reasons it should not be modified for standard renewable avoided cost prices.

ISSUE 6: DO THE MARKET PRICES USED DURING THE RESOURCE SUFFICIENCY PERIOD SUFFICIENTLY COMPENSATE FOR CAPACITY?

Q. Did any party claim that market prices do not sufficiently compensate for capacity during the sufficiency period?

A. Yes. The Joint QF Parties claim that market prices are not sufficient to calculate avoided cost prices during the sufficiency period, and they propose two alternatives to increase sufficiency period prices by including the cost of environmental upgrades at existing coal facilities and using an alternative IRP scenario assuming no existing QF contracts are extended to determine the year of the next deferrable resource.[9] REC,

[8] Staff/500, Andrus/21.
[9] Joint QF Parties/100, Higgins/4-6.

one of the Joint QF Parties, also argues that existing QFs which renew contracts should be paid for capacity even if the utility is in a resource sufficiency period.[10]

Q. Did any party support that market prices sufficiently compensate for capacity during the sufficiency period?

A. Yes. Staff supports the use of market prices during the sufficiency period, and that the deficiency period appropriately begins with the start date of the utility's next planned major resource acquisition.[11]

Q. Does any other party address this issue?

A. ODOE argues that the answer depends on the actual purchasing practices of a utility, but that specific determination could be made in the review of the utility's avoided cost calculations.[12] ODOE suggests that if the utility typically purchases capacity separate from energy, or if it contracts for longer terms at fixed prices, then short term wholesale power prices might not reflect the costs the utility will actually avoid.

Q. Does PacifiCorp typically engage in either activity identified by ODOE?

A. No. In its IRP PacifiCorp identifies that during the sufficiency period it relies on 'front office transactions', which are representative of short-term firm wholesale market purchases, to balance the Company's capacity needs. Therefore, PacifiCorp does not currently utilize the types of transactions that would, in ODOE's opinion, render market prices during the sufficiency period inaccurate.

[10] Coalition/400, Lowe 20.
[11] Staff/500, Andrus/30–31.
[12] ODOE/700, Carver/10.

Sufficiency Period Environmental Upgrades

Q. Please summarize the proposal made by the Joint QF Parties related to additional capacity costs during the sufficiency period.

A. The Joint QF Parties recommend that the Commission adopt an 'interim capacity pricing mechanism' for renewable and zero-emitting QFs until the uncertainty surrounding the rules proposed by the Environmental Protection Agency (EPA) under Section 111(d) of the Clean Air Act is resolved.[13] The Joint QF Parties propose to pay renewable and zero-emitting QFs the average cost of environmental upgrades at existing Company-owned coal-fired generation resources during the sufficiency period. This additional capacity payment would be added to the market prices otherwise paid to a QF during the sufficiency period.

The Joint QF Parties suggest EPA's proposed Section 111(d) rules create a significant incentive for the Company to acquire renewable resources but that the long sufficiency period in the Company's 2015 IRP discourages development of renewable and zero-emitting QFs. The Joint QF Parties then conflate issues surrounding compliance with Section 111(d) rules and certain planned and potential capital investments at existing coal facilities during the resource sufficiency period to comply with the EPA's Regional Haze Rule under the Clean Air Act – an entirely different compliance issue.

Q. Is the Joint QF Parties' proposal that QFs be paid the capacity for environmental upgrades to existing coal plants reasonable?

A. No. The Joint QF Parties' proposal is fatally flawed for the following reasons:

[13] Joint QF Parties/100, Higgins/6.

- The referenced environmental upgrades include capital investment that cannot be avoided by the addition of an Oregon QF, even one that is renewable or non-emitting.
- Several of the referenced environmental upgrades that were included in the IRP for planning are not currently required, and alternative compliance scenarios may eliminate the need for the investment irrespective of any new QF generation.
- There is no accounting for the benefits of the existing generation resources that will be lost if the environmental upgrades are eliminated.

Q. Please explain how the proposal includes costs that cannot be avoided.

A. The first flaw in the Joint QF Parties' proposal is that it implies the environmental upgrades at specific coal plants located in Utah, Wyoming, Colorado, Montana, and Arizona can be avoided by renewable and non-emitting QFs in Oregon. In reality, all of the upgrades listed by the Joint QF Parties are for compliance with the Regional Haze Rule intended to improve the air quality and visibility in national parks and wilderness areas in the proximity of the emitting resource. PacifiCorp cannot avoid these compliance costs by simply adding an Oregon QF.

Furthermore, construction of several of the projects referenced by the Joint QF Parties is already underway, underscoring the fact that costs cannot be avoided and should not be included in the determination of avoided costs. In fact, the Hayden 1 SCR has already been placed in service. Engineering, design, and procurement for the Hayden 2, Jim Bridger 3, and Jim Bridger 4 SCR projects are likewise already underway.

Q. What do you mean that several of the environmental upgrades may not be needed?

A. The second flaw in the Joint QF Parties' proposal arises because the list of capital projects includes SCR projects for which there is no such requirement yet in place (including SCRs at Hunter 1, Hunter 3, and Huntington 1). Although the Joint QF Parties recognize that the 'agency, regulator, and joint owner perspectives on acceptability have not necessarily been determined'[14] they recommend that the entire list of projects be used to calculate an average cost of capacity to be included in avoided costs during the sufficiency period. As requirements are finalized, and decisions on Regional Haze-related investments are ripe they will be included in an IRP for Commission review and acknowledgement.

Potential alternatives to meeting Regional Haze compliance without installing SCR technology include retiring the unit altogether or converting it to be fueled by natural gas. The timing of such compliance alternatives is often different than the SCR installation, and the Company's IRP provides extensive inter-temporal and fleet trade-off analyses related to Regional Haze compliance. An example from the list of projects included in the Joint QF Parties' proposal is the Cholla 4 conversion to natural gas by June 2025. The initial compliance plan for Cholla 4 called for SCR installation by June 2017, but the alternative plan to convert the unit to natural gas by June 2025 is now under review by the EPA. This delay eliminates the cost of SCR installation and also pushes the deadline beyond the sufficiency period,[15] rendering the Joint QF Parties' proposal moot.

[14] Joint QF Parties/100, Higgins/15.

[15] Current avoided cost rates are based on the 2013 IRP and a deficiency period beginning in 2024. In the 2015 IRP, the next major thermal resource acquisition is in 2028.

Q. Please explain how the Joint QF Parties' proposal fails to account for the benefits lost if the environmental upgrades are eliminated.

A. The third flaw in the Joint QF Parties' proposal is that it fails to account for the significant impact on the Company's generation portfolio if the required environmental upgrades are eliminated. Coal plants provide low-cost base load generation as well as operating reserves and load following capability. The decision to invest in environmental upgrades is evaluated in the Company's IRP, and takes into consideration the value of retaining the generation from the plant and the inter-temporal and fleet trade-off alternatives.

Eliminating an environmental upgrade that is specifically required to comply with Regional Haze means the Company will no longer be able to operate the plant as a coal-fired generator. The Joint QF Parties' proposal ignores the obvious impracticality of replacing an entire existing coal unit with many individual renewable QFs. For example, the second project on the list is the SCR at Jim Bridger unit 3, which is scheduled to be placed into service in December 2015. Utilizing the capacity contribution of 36.7 percent for a single axis tracking solar project (the highest of the wind and solar capacity contributions) listed in the 2015 IRP equates to a need for over 950 megawatt (MW) of new solar capacity from QFs to replace PacifiCorp's approximately 350 MW share of the capacity lost by eliminating Jim Bridger unit 3. This already unrealistic result doesn't account for the lost dispatchability and lost energy from a base load generator.

Q. The Joint QF Parties emphasize that it is uncertain what the final Section 111(d) rules will be, and that changes to the draft rules or assumptions used in the Company's 2015 IRP may result in a different resource sufficiency period. Do you agree that this uncertainty supports adopting the Joint QF Parties' proposal?

A. No. On the contrary, the uncertain nature of the draft Section 111(d) rules is one more reason to reject the Joint QF Parties' proposal to artificially inflate avoided costs during the sufficiency period. The Company will continue to plan future resource acquisitions to minimize costs and risk to customers. The preferred portfolio in the Company's 2015 minimizes cost and risk in complying with draft Section 111(d) rules, and that solution does not call for acquisition of new long term renewable resources. Furthermore, in Oregon the Company does not receive RECs during the sufficiency period and future regulations will be needed to determine how ownership rights for RECs will be treated under Section 111(d). As indicated by the Joint QF Parties, the outcome of such regulation is uncertain at this time. Imputing additional costs into the avoided cost formula on the premise of unknown and uncertain future changes to the proposed regulations, and based on unrelated compliance investments, will only overstate avoided costs and violate the ratepayer indifference standard embodied in PURPA.

<u>Alternative Resource Portfolio</u>

Q. Please summarize the proposal made by the Joint QF Parties related to the timing of the deficiency period.

A. The Joint QF Parties argue that the timing of the next major resource acquisition in the Company's IRP may be delayed due to an assumption that some existing small QF contracts will be renewed at the end of their term. The Joint QF Parties note that approximately 122 MW of existing small QFs whose contracts expire prior to 2028 were assumed to be renewed and included in the 2015 IRP.

Q. Does the assumed renewal of small QF agreements in the IRP preferred portfolio result in an unwarranted extension of the sufficiency period as suggested by the Joint QF Parties?

A. No. Between the preparation of the 2013 IRP, which is still being used as the basis for Oregon standard avoided cost prices, and the recently filed 2015 IRP, the Company executed contracts with new QF projects totaling more than 800 MW of nameplate capacity. Since the time the 2015 IRP inputs were finalized, the Company has executed contracts with new QF projects totaling more than 300 MW of additional nameplate capacity. Because the demarcation of the deficiency period for standard avoided cost prices can only be updated when an IRP is acknowledged, the timing of the sufficiency period is already out of date. If the Commission determines the Company's preferred portfolio should be updated to account for small QF terminations, new QF contracts should also be accounted for in order to accurately reflect the Company's resource needs.

Q. Should the Company be required to provide an alternative resource portfolio for the purposes of determining the next deferrable resource for standard avoided cost prices?

A. No. The valuation of QF capacity would be more accurate if the Company's capacity position and preferred portfolio was updated to reflect changes since the IRP was finalized. Many assumptions in the current QF valuation are nearly three years out of date as they were finalized in the fall of 2012 for the 2013 IRP.

Capacity Payments at the Time of Renewal

Q. Should renewing QFs receive a capacity payment even if the utility is in a resource sufficiency period?

A. No. REC argues that renewing QFs should receive a capacity payment since they would have been receiving one the last few years of an existing contract. A utility's avoided costs are not static, and for this reason, it is logical that avoided cost prices need to be updated to account for changes in market and system conditions, including changes in a utility's capacity needs over time. As avoided cost prices are updated and new contracts sought, the most current avoided cost price information should be applied to the new contract consistent with the customer indifference standard under PURPA. REC's proposal is a thinly-veiled attempt at locking in capacity payments beyond the maximum 20-year contract term currently allowed in Oregon. The Company recommends the Commission reject this proposal.

Q. Is REC's proposal consistent with the Joint QF Parties' (which include REC) proposal to move up the sufficiency period by removing all QFs from the load and resource balance in the IRP?

A. No. In short, REC proposes to pay existing QFs avoided capacity costs in perpetuity, and at the same time assume those QFs do not exist when determining the timing of capacity payments for new QF projects.

Q. Would guaranteeing a capacity payment to a renewing QF over 20 years in advance be harmful to customers?

A. Yes. Given the typical contracting and hedging horizons for energy contracts in the utility industry, which are commonly limited to less than 36 months, it is extremely rare for a utility to voluntarily enter into a 20-year fixed-price energy contract without a specified energy resource need due to concerns about price risk, market liquidity, prudency challenges, and other risk considerations. Under the Commission's current policies, any QF can obtain a 20-year contract at the Company's projected avoided cost, with prices fixed for 15 years without any adjustment to account for the risk to utility customers from this unusual long-term transaction. Guaranteeing a capacity payment to renewing QFs magnifies the risk and potential harm to customers by providing fixed-price contracts for excessive time periods. A QF seeking a new contract upon expiration of an existing contract should be treated the same as other QFs and avoided cost prices should reflect the utilities then current energy and capacity needs at the time of renewal.

ISSUE 7: WHAT IS THE MOST APPROPRIATE METHODOLOGY FOR CALCULATING NON-STANDARD AVOIDED COST PRICES? SHOULD THE METHODOLOGY BE THE SAME FOR ALL THREE ELECTRIC UTILITIES OPERATING IN OREGON?

Q. Did any party address the method for calculating non-standard avoided cost prices?

A. Yes. REC and CREA object to the use of a model-based approach for calculating non-standard avoided costs. REC claims that using a model is too complex and subject to dispute, while CREA argues that using a model is too costly and complex.

Q. Did any party support PacifiCorp's proposal made in Phase 1 to use its GRID model for non-standard avoided costs?

A. Yes. Staff supported use of economic dispatch models to calculate non-standard avoided costs, stating, "The complexity of the modeling approach for larger QFs is justified, as it is likely to provide a more accurate quantification of the impact of a QF based on its specific characteristics than a generic CCCT calculation with adjustments applied to it."[16]

Q. Is using GRID to determine non-standard QF prices too costly and complex?

A. No. The Company provides transparent access to GRID for all interested parties and even provides GRID training. In fact, the GRID model is routinely used by the Company in Utah, Idaho, and Wyoming to set non-standard QF prices.

Q. Is using GRID to determine non-standard QF prices more accurate than the current method?

A. Yes. As noted in my direct testimony, by using GRID the unique characteristics of each QF are accounted for in determining the value of the energy and capacity on the Company's system. In my Phase 2 direct testimony I also described how the GRID model should be used to account for all proposed QFs on the Company's system to most accurately determine the avoided costs attributable to the next QF requesting non-standard prices.

<u>Recommendation</u>

Q. What does the Company recommend?

A. The Company recommends the following:

[16] Staff/500, Andrus/34.

- The sufficiency period should not be based on an alternative preferred portfolio;
- Environmental upgrades to coal plants should not be included in avoided costs;
- Market prices in the sufficiency period are adequate for standard prices;
- The solar resource adder should not be modified;
- Gateway West transmission upgrade should not be included in avoided costs;
- Avoided costs should include transmission upgrades if directly associated with the proxy resource;
- Renewing QFs should not automatically receive capacity payments; and,
- GRID should be used to determine non-standard prices.

Q. Does this conclude your response testimony?

A. Yes.

Docket No. UM-1610
Exhibit PAC/1200
Witness: Ted Drennan

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Response Testimony of Ted Drennan

July 2015

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Q. Are you the same Ted Drennan who previously submitted direct testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or Company)?

A. Yes.

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your response testimony?

A. The purpose of my testimony is to respond to parties' direct testimony related to Issue 5 listed in Attachment A – UM 1610 Phase II Issues List as included in Administrative Law Judge Traci Kirkpatrick's March 26, 2015 Ruling:

- *Issue 5. What is the appropriate forum to resolve litigated issues and assumptions?*

Q. Does the fact that you are not commenting on other issues raised in the direct or response testimony of these or other witnesses indicate that you agree with their positions?

A. No. I believe that other issues raised by witnesses for opposing parties have been more than adequately addressed in the direct testimony and response testimony filed by the Company's other witnesses.

Q. Is the Company filing response testimony of any other witness in this Docket?

A. Yes. Company witness Mr. Brian S. Dickman responds to the direct testimony of several parties on avoided cost methodology and pricing issues including issues 2, 3, 4, 6, and 7 from the UM 1610 Phase II Issues List. Mr. Bruce W. Griswold responds to the direct testimony of several parties on issues 1, 8, and 9.

Q. Please summarize your testimony.

A. As stated in my Phase 2 direct testimony, the Integrated Resource Plan (IRP) process is the proper forum to establish modelling assumptions used for determination of the characteristics of the costs and timing of a utility's avoided resource. Parties have not offered persuasive testimony in support of any other option. Several proposals put forth fail to recognize, or intend to break, the link between the IRP and avoided cost rates. The majority of the parties have suggested additional processes that are duplicative in nature and offer no tangible benefits.

Q. Is there consensus among parties on the appropriate forum to resolve disputed issues?

A. No. Parties suggested very different options on resolving disputed issues. The Oregon Department of Energy's (ODOE) recommends that utilities file avoided cost updates and Integrated Resource Plans (IRPs) concurrently thereby allowing avoided costs to be litigated in a proceeding that parallels the IRP acknowledgement proceeding. The Renewable Energy Coalition (REC) recommends expanding the IRP process to allow parties to formally challenge avoided cost inputs and assumptions within the IRP docket. The Public Utility Commission of Oregon Staff (Staff) recommends that resource sufficiency/deficiency determinations made in the IRP process should be subject to challenge in avoided cost updates. Idaho Power Company (Idaho Power) recommends that a PURPA docket be opened when there are disputed inputs. Portland General Electric (PGE), like PacifiCorp, recommends maintaining the current Commission policy wherein utilities use inputs from their last acknowledged IRP as the basis for avoided cost prices.[1]

Q. Please explain your concern with having parallel proceedings to look at a utility's IRP and avoided cost inputs simultaneous as suggested by ODOE.

A. A major concern is that parallel IRP and avoided cost processes could result in different conclusions after examining the same issues, data, and assumptions. For example, utilities could have one resource sufficiency/deficiency demarcation developed in the IRP used to guide resource procurement activities, but a different demarcation for avoided cost prices. There are numerous planning assumptions (i.e., load forecasts, changes to existing resource availability and capacity ratings, generator operating costs, capacity contribution values, etc.) that influence the type, timing, and location of future resources in the IRP. If any of these assumptions are modified in a parallel proceeding, then the Company's resource portfolio used for avoided cost pricing would almost certainly be modified and would immediately be out of alignment with its resource procurement plan.

ODOE states its recommended approach would be beneficial as it "would allow parties to challenge the assumptions underlying the calculation of avoided costs."[2] Not only is ODOE's recommended approach duplicative, any process that has potential to establish alternative assumptions for avoided cost pricing separate from assumptions supporting resource procurement plans could yield avoided cost prices that are not aligned with the Company's best estimate of its true avoided cost at

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[1] UM 1610 Brief in Support of Stipulation dated 02/26/15 at 8.
[2] ODOE/700, Carver/5.

any given point in time—an outcome that is inconsistent with the customer indifference standard under the Public Utility Regulatory Policies Act (PURPA).

Q. Is there already an existing process that would allow parties to challenge assumptions underlying the calculation of avoided costs?

A. Yes. The existing IRP process provides ample opportunity for parties to influence key planning assumptions that are applied to avoided cost price calculations. Parties can participate in the IRP public process which is initiated up to a year prior to filing each IRP. During this public process, the Company hosts numerous public input meetings and workshops where parties can offer comments, recommendations, and generally influence key planning assumptions. Once the IRP is filed with the Commission, the IRP acknowledgement process provides additional opportunity for parties to file multiple rounds of comments with the Commission and participate in additional workshops and public meetings.

Q. Do other parties have concerns about challenging IRP assumptions?

A. Yes. REC claims that the current IRP process does not "provide stakeholders an opportunity to challenge and obtain a Commission decision" for IRP assumptions.[3] Similarly, CREA argues that "interested parties should have the opportunity to fully review avoided cost rates and the myriad of assumptions that are behind those rates."[4]

Q. Are these concerns valid?

A. No. These claims do not hold up to scrutiny. The IRP process, which drives avoided cost price assumptions, is a robust and transparent process as discussed more fully in my direct testimony and as described above. Not only is there ample opportunity for

[3] Coalition/400, Lowe/12.
[4] CREA/500, Skeahan /14.

parties to influence key planning assumptions, the IRP is subject to Commission review and acknowledgement.

Q. Please describe the regulatory process following the IRP filing.

A. After filing the IRP, intervenors have the opportunity to present the utility with interrogatories or data requests. Parties generally take full advantage of this opportunity. As of June 30, 2015 PacifiCorp had received 127 such requests for the 2015 IRP from Oregon parties (not including subparts). In the 2013 IRP, the Company responded to 435 data requests from Oregon parties, including thirteen Bench Requests at the conclusion of the 2013 IRP.

Q. How are intervenor inputs reflected in the IRP process?

A. Parties may express concerns with any assumptions or inputs in filed comments. The IRP regulatory schedule affords intervenors multiple opportunities to comment on all aspects of the IRP. There are no limits on what inputs and assumptions may be addressed. The 2015 IRP regulatory schedule includes four rounds of comments. Following the comment period, Staff presents its recommendation memorandum to the Commission.

Q. Does the Commission consider feedback from intervenors?

A. Yes. One of the last steps prior to ruling on the IRP is a public meeting before the Commission. Staff presents its recommendation memorandum, intervenors are offered an opportunity to comment, and the utility also has an opportunity to address the Commission. The Commissioners often solicit feedback and ask questions of all parties. The final step is for the Commission to issue a ruling on acknowledgement.

Such a ruling will consider the totality of the materials offered in the docket as specified in IRP Guideline 3.d.

> The Commission will consider comments and recommendations on a utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the utility an opportunity to revise the plan before issuing an acknowledgment order.[5]

This process provides parties with many opportunities to influence key planning assumptions that affect avoided cost prices.

Q. Do parties believe there are shortcomings in the current process?

A. Yes. For instance ODOE believes there are issues in an IRP that will not be addressed in a Commission order at the end of an IRP proceeding. One such issue cited is the renewable resource need for RPS requirements in PacifiCorp's 2015 IRP.

Q. How do you respond?

A. In this instance ODOE is simply misinterpreting PacifiCorp's 2015 IRP. ODOE states, "The IRP assesses renewable resource needs to fulfill the RPS requirements only through 2024 (IRP page 194, see Exhibit 701, pages 2-3)."[6] PacifiCorp's 2015 IRP examines a twenty-year period planning horizon as called for in the IRP Guidelines; renewable requirements in all of its states are addressed as part of this twenty-year planning horizon. The graph ODOE cites is simply summarizing the twenty-year RPS compliance position over the front ten years of the planning horizon.

Q. Does ODOE raise other potential issues for consideration in a parallel process?

A. Yes. Some other potential issues include wind integration, capacity credit for

[5] UM 1056, Order No. 07-002 at Appendix A, 3 (Jan. 8, 2007).
[6] ODOE/700, Carver/7.

renewables, and forecasts of market prices. All of these assumptions with backing data are included in the IRP. PacifiCorp reviewed each of these items in detail with stakeholders that participated in the 2015 IRP public process. Further, PacifiCorp documents its key assumptions, methods and results in the IRP filed with the Commission. Parties can now provide comment on each of these items during the IRP acknowledgement process. This is the appropriate forum to review and challenge these types of assumptions to ensure that PacifiCorp's avoided cost prices are aligned with its resource procurement plan.

The proposed parallel-proceeding approach has the effect of de-linking the IRP and avoided costs, which would result in one set of assumptions for IRP and resource acquisition purposes and a different set for establishing avoided cost prices. This would be a fundamental change to Oregon's historic approach most recently recognized in Order No. 14-058 from Docket UM 1610:

> Calculation of each utility's standard avoided costs begins with the utility filing an IRP for a 20-year planning horizon, as required every two years. Utilities' avoided cost methodologies were designed to capture the avoided costs actually realized by the utility when it purchases power from a QF, and are intended to be simple and clear, with inputs and assumptions taken from IRPs that are subject to stakeholder review.[7]

Q. Staff does not believe there will be additional litigation following adoption of their recommendation on resource sufficiency/ deficiency. Do you agree?

A. It is difficult to say. Parties have suggested expanded avoided cost processes; REC states "An expanded post-filing process has the advantage of clearly separating the

[7] Docket No. UM 1610, Order No. 14-058 at 12 (Feb. 24, 2014).

IRP from avoided cost rates."[8] ODOE believes if their parallel process is not adopted there would be need for a lengthy avoided cost proceeding following IRP acknowledgement. The avoided cost proceeding "would result in a delay similar in length to the nine month IRP proceeding."[9]

Clearly other parties envision lengthy avoided cost processes following an acknowledgement order. This is precisely the problem with litigation following acknowledgement of an IRP. Adoption of updated avoided costs that align with the most current forecasts would be delayed. Assumptions informing avoided costs would almost certainly be stale following potentially 19 months of process as suggested by ODOE.[10]

Q. Are there other issues with an extended process?

A. Yes. This would again have the impact of de-linking the IRP assumptions and avoided costs. In a process that takes 19 months the annual IRP Update would supersede an acknowledged IRP prior to the end of the avoided cost proceeding. This is simply not a workable option if the Commission intends to rely on acknowledged IRPs as the basis for avoided cost rates.

Q. Has the Commission limited review of avoided cost filings in the past?

A. Yes. In denying an application for reconsider/clarification the Commission observed that PUPRA policies are set in generic investigations, which in turn speed up and simplify the review of avoided cost updates.[11] Parties argued that,

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[8] Coalition/400, Lowe/16.
[9] ODOE/700, Carver/5.
[10] As a simple example, there could be a potential 19 months total between filing of an IRP and the effective date of avoided costs based on said IRP. That is, acknowledgement order nine months following IRP filing, then one month for filing avoided costs, finally another nine months before costs would become effective.
[11] Order No. 09-427.

> (I)t is preferable to review all issues regarding the accuracy of Pacific Power's avoided cost in a single proceeding, and that all relevant issues should be "consolidated and addressed in the same proceeding to ensure that the final order takes a consistent and holistic approach to PacifiCorp's avoided cost rates."[12]

The Commission was not persuaded. Instead determined that any investigation would "be limited to the issue of whether the company's avoided costs were calculated in compliance with the methodologies adopted by the Commission in Docket UM 1129."[13] It is clear from the order that the Commission did not see value with re-litigating issues recently settled.

Q. Staff suggests challenging the utility's IRP determination of sufficiency/deficiency in an avoided cost proceeding. Do you support this?

A. No. Staff cites OAR 860-029-0080 (6) in support of stakeholder review.[14] Staff's argument is that all aspects of the avoided cost filing are subject to review and revision, and changes in one variable may change the resource sufficiency/deficiency demarcation. It is correct that changes in variables could impact the sufficiency/deficiency period for a utility that optimizes portfolio selections in their IRP. However, the IRP review process should itself examine any such issues. Parties should not immediately re-litigate assumptions 30 days following an acknowledgement order. To do so devalues the IRP process, IRP outcomes, and creates uncertainty.

Q. Are there issues with granting suspensions of avoided cost filings?

A. Stakeholders can "seek suspension of an avoided cost filing when necessary to address concerns about natural gas forecasts, or any other aspect of a utility's

[12] Order No. 09-427 at 4.
[13] Order No. 09-427 at 2.
[14] Staff/500, Andrus/23.

filing."[15] At the same time, the Commission has also noted that "the legislature has not mandated an investigation or hearing to determine the reasonableness of [avoided cost prices]."[16]

Therefore, requests to suspend and investigate avoided cost updates should be heavily scrutinized prior to granting such suspensions, especially following acknowledgement of an IRP. As discussed in my direct testimony, the Commission has repeatedly recognized that it is appropriate for the Company to rely on inputs and assumptions developed in an acknowledged IRP when setting avoided cost prices. These inputs and assumptions were fully vetted in the utility's acknowledged IRP, and do not require a second round of litigation. Therefore, requests for suspension following acknowledgement of a Utility's IRP such requests should be rare.

Q. What is the purpose of standard avoided cost prices?

A. Standard avoided cost prices are developed to allow small, relatively unsophisticated QFs to secure avoided cost pricing without engaging in protracted pricing negotiations with utilities. Under FERC's regulations, standard avoided cost prices are available to QFs with a design capacity of 100 kW or less.[17] The Commission has adopted a 10 MW threshold for standard avoided cost prices, explaining that "standard contract rates are intended to be used as a means to remove transaction

[15] *In the Matter of Public Utility Commission of Oregon Staff's Investigation Relating to Electric Utility Purchases from Qualifying Facilities*, Docket UM 1129, Order No. 05-584 at 36-37.
[16] *In the Matter of Public Utility Commission of Oregon Investigation to determine if Pacific Power's rate revision has been consistent with the methodologies and calculations required by Order No. 05-584*, Docket UM 1442, Order No. 09-427 at 3.
[17] 18 C.F.R. § 292.304(c).

costs associated with QF contract negations, when such costs act as a market barrier to QF development."[18]

Q. Would a framework for protracted litigation over standard avoided cost prices benefit small QFs?

A. No. Presumably genuinely small QFs would not have the resources available to engage in protracted and detailed litigation over avoided cost inputs. Standard avoided cost prices are intended to be a simply-derived approximation of actual avoided costs, and are available to reduce market barriers faced by small QFs. By basing standard avoided cost prices on inputs developed and vetted in the IRP process, the Commission has established a framework for developing standard avoided cost prices that does not require small QFs to have significant technical and legal resources to participate.

QFs with the technical and legal resources available to engage in protracted litigation over avoided cost pricing updates presumably also have the resources available to negotiate project-specific rates under Schedule 38. And while Schedule 38 is currently based on Schedule 37 prices, testimony presented by Mr. Brian S. Dickman on PacifiCorp's behalf demonstrates that non-standard prices should be developed using the GRID model in order to develop more accurate avoided cost prices.[19]

[18] Docket UM 1610, Order No. 14-058 at 7 (Feb. 24, 2014).
[19] Pac/1100, Dickman/19-20.

MINIMUM FILING REQUIREMENTS

Q. Two parties have proposed establishing Minimum Filing Requirements (MFR) in the avoided cost filings. Do you believe MFRs would streamline the avoided cost process?

A. REC and Staff have both proposed that utilities include MFRs with their avoided cost updates. *See* Coalition/400, Lowe/17-18; Coalition/403, Lowe/1-2; Staff/500, Andrus/26-28. Requiring utilities to include MFRs will add additional work and not streamline the avoided cost review process at all. Much of the information proposed for MFRs is already available in the IRP. While not an exhaustive list, some such examples include: sufficiency/deficiency demarcation, supply side resource costs, capacity contribution assumptions with supporting analysis, and financial assumptions. As setting avoided costs follow acknowledgement of an IRP, these assumptions will have been well-vetted prior to making an avoided cost filing. At that point parties have ample information and opportunities to be well versed in the IRP assumptions. As such it is difficult to see the value associated with a utility presenting the data again in another forum.

Q. Do parties realize they are suggesting duplicative processes?

A. It appears so. Staff states, "It is very likely all this information may be found in the utility's IRP and possibly in workpapers that may accompany the utility's avoided cost filing." (Staff/500, Andrus/27)

REC also notes that, "Some of this information is already included in the utilities' IRPs..."[20] Coalition Exhibit 403 is a three page list of proposed MFRs, many

[20] Coalition/400, Lowe/17.

of which are included in the IRP. For instance, Item 2c in Coalition 403 calls for the utility to "provide a complete explanation of the basis for the utility's use of the gas price forecast, and any differences from the gas price forecast in the last Commission-approved IRP" Gas forecasts are covered in the IRP, duplicating such discussion in an avoided cost filing is not particularly useful.

Q. Do parties request additional analysis unrelated to the calculation of avoided costs?

A. Yes, some proposed MFRs ask for new information. For instance, REC would like to require that an avoided cost filing, compare "proposed gas forecast to the most recent EIA and Northwest Power and Conservation Council gas forecast".[21] Parties to the docket are free to make any comparisons they would like; it should not be a requirement in a utility filing.

Q. Do you have other concerns about the extensive nature of the MFRs?

A. Yes. Avoided cost inputs are reviewed as part of the robust IRP process. Requiring extensive MFRs (especially those requiring new analysis) will lead to additional litigation in the avoided cost dockets. This will prolong the avoided cost process with no tangible benefits.

CONCLUSION

Q. Please summarize your position on Issue 5.

A. The appropriate forum to resolve litigated issues and assumptions is a Company's IRP. Recommendations for alternative or expanded processes move the Commission away from the practice of linking IRP and avoided costs. Such approaches will

[21] Coalition/403, Lowe/1.

increase uncertainty for utilities and QFs alike along with devaluing the current IRP planning process.

As issues and assumptions should be fully litigated in the IRP there is little to be gained with requiring MFRs in the succeeding avoided cost process.

Q. Does this conclude your response testimony?

A. Yes.

Docket No. UM-1610
Exhibit PAC/1300
Witness: Bruce W. Griswold

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Response Testimony of Bruce W. Griswold

July 2015

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Q. Are you the same Bruce W. Griswold who previously submitted direct testimony in this proceeding on behalf of PacifiCorp d/b/a Pacific Power (PacifiCorp or Company)?

A. Yes.

PURPOSE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your response testimony?

A. The purpose of my testimony today is to respond to parties' direct testimony on Issues 1, 8 and 9. I will be responding to the proposals and analysis presented by Brittany Andrus on behalf of Public Utility Commission of Oregon staff (Staff); John Lowe on behalf of Renewable Energy Coalition (REC); Bill Eddie on behalf of OneEnergy Renewables, Inc. (OneEnergy); Joe Benga on behalf of Gardner Capital Solar Development LLC (Gardner); Philip Carver and Diane Broad on behalf of the Oregon Department of Energy (ODOE); and Brian Skeahan on behalf of the Community Renewable Energy Association (CREA).

Q. How is your testimony organized?

A. My testimony is organized consistent with the list of issues identified for Phase II and presented in my direct testimony including:

- *Issue 1. – Who owns the Green Tags during the last five years of a 20-year fixed price PPA during which prices paid to the QF are at market?*
- *Issue 8. – When is there a legally enforceable obligation?*
- *Issue 9. – How should third-party transmission costs to move QF output in a load pocket to load be calculated and accounted for in the standard contract?*

Q Does the fact that you are not commenting on other issues raised in the direct or response testimony of these or other witnesses indicate that you agree with their positions?

A. No. I believe that other issues raised by witnesses for opposing parties have been more than adequately addressed in the direct testimony and response testimony filed by the Company's other witnesses.

Q. Is the Company filing response testimony of any other witness in this Docket?

A. Yes. Company witness Mr. Brian S. Dickman responds to the direct testimony of several parties on avoided cost methodology and pricing issues including issues 2, 3, 4, 6, and 7 from the UM 1610 Phase II Issues List. Mr. Ted Drennan responds to parties' direct testimony on issue 5 related to the forum for resolving litigated issues and assumptions used when developing avoided cost prices.

ISSUES

ISSUE 1: WHO OWNS THE GREEN TAGS DURING THE LAST FIVE YEARS OF A 20-YEAR FIXED PRICE PPA DURING WHICH PRICES PAID TO THE QF ARE AT MARKET?

Q. Please summarize the Company's position in your direct testimony.

A. The Company's position is that a renewable Schedule 37 PPA is based on avoidance of the renewable proxy by the QF, and at the point in time that the resource deficiency period starts through the end of the PPA, the Green Tags[1] should go to the Company consistent with the avoidance of that renewable resource. It was clear from Order No. 11-505 that the Company would receive the Green Tags through the resource deficiency period or going forward from the point in time that the Company

[1] In my testimony, I will also refer to Green Tags as Renewable Energy Credits or RECs.

had identified a need for a new renewable resource in its IRP used to set the Schedule 37 avoided cost prices.

It is also clear that the purpose of contract term as established under Order No. 05-584 was to provide certainty for QFs to secure financing, not to establish a return to resource sufficiency period because of the QF's option to accept market prices during the last five years of a PPA. Therefore, the Company's position is that the Green Tags should be awarded to the utility upon the beginning of the resource deficiency period as established by the IRP and documented in Schedule 37 for the remainder of the QF contract term. If a QF does not want to transfer the RECs to the utility, it can choose to secure only a 15-year PPA. Quite frankly, many of the renewable QFs execute 15-year QF contracts. Their decision on contract term is not because of the REC ownership.

Q. Has your position changed?

A. No.

Q. Do you agree with Mr. Carver's interpretation of Commission Order No. 11-505?

A. No. First, Mr. Carver acknowledges the statement by the Commission in Order No. 11-505 that the QF will transfer the RECs to the purchasing utility during the resource deficiency period and then goes on to state that even though the QF is paid market, the resource deficiency period is no longer applicable. That is simply not correct. The resource deficiency period is not based on the change back to market prices at all, rather the resource deficiency period is established and set through the Company's IRP process. The market price change is solely based on the Commission's policy determination in UM 1129[2] that QFs should receive a maximum 15-year fixed price portion of its allowed 20-year term to assist the QF in securing financing of its project, not that the resource deficiency period ended. A QF can simply execute a 15-year contract if it does not want market prices for the last 5 years. The term of the contract and the use of market prices in the contract are completely independent of when the resource deficiency period starts and stops.

Q. Does the Company include an incremental value for RECs as part of its renewable avoided cost prices?

A. No. Mr. Carver infers that the Company is including the cost of a REC in its renewable avoided cost. That is not correct. The Company establishes the timing and cost of the renewable resource to meet its RPS obligation through its IRP process. The QF can choose that renewable avoided cost stream for the full fixed-price portion of its contract term based on Commission Order No. 05-584 from UM 1129. The QF cannot choose to receive standard avoided cost prices in the last five years of a 20-year term. If the QF chooses to contract for a full 20-year term, the last five years, as ordered by the Commission, is a market price option. The QF could just have as easily contracted for only the fixed 15-year term retaining the RECs in the resource sufficiency period and transferring them to the utility in the resource deficiency period.

Q. Many of the parties argue that the QF should retain the RECs if the QF is being paid market-based avoided costs during the resource deficiency period. Do you agree?

A. No. The Company's resource deficiency period is determined through its IRP

[2] UM 1129, Order No. 05-584.

process and establishes the point in time for the Company's need of a new resource that then becomes the basis for Schedule 37 and the renewable stream of avoided cost prices. Mr. Carver, along with several other parties including Ms. Andrus, Mr. Eddie, and Mr. Skeahan, are equating being paid market-based avoided costs during the resource deficiency period to the Company returning to a resource sufficiency period and therefore the RECs should be retained by the QF. However, that is not the case at all. The resource deficiency period did not end but the reference point for avoided cost prices available to the QF does change based on the Commission's decision in Order No. 05-584 in UM 1129 to continue to offer the QF the option for a 20-year term while limiting customers exposure to fixed prices to 15 years. The price paid to the QF for the last five years of a 20-year contract, if the QF chooses to seek a 20-year contract, is market, not because the Company suddenly reverted to a resource sufficiency period or is forcing the QF to select standard avoided cost prices but because the Commission sought to provide the balance between giving the QF access to a long-term contract while protecting customers from the divergence between forecasted and actual avoided costs over a 20-year period.

ISSUE 8: WHEN IS THERE A LEGALLY ENFORCEABLE OBLIGATION?

Q. Please summarize the recommendation made in your direct testimony.

A. The Company proposes that the Commission set criteria for establishing a legally enforceable obligation (LEO) using the milestone of the QF approving the final draft PPA as contemplated in B(5) on page 10 of Schedule 37[3].

[3] While the focus of my testimony on Issue 8 is toward Schedule 37, the testimony is meant to be inclusive of Schedule 37 and Schedule 38 QF contracts.

Q. Has your recommendation changed?

A. No.

Q. Do you agree with Mr. Skeahan regarding CREA's LEO position as proposed in their direct testimony?

A. No. First, Mr. Skeahan references the direct testimony of Mr. Hilderbrand[4] so I will address Mr. Hilderbrand's testimony. In Mr. Hilderbrand's direct, he argues that the Company's proposal overlooks the issue of a disagreement prior to reaching a final draft contract that could frustrate a QF's right to obligate itself to sell power and lock in rates. That argument points to there being no dispute resolution process available to the QF, when in fact the Company's Schedule 37 already provides for a Commission-based dispute resolution process.

Mr. Skeahan also points to using a process established by the Federal Energy Regulatory Commission (FERC) under a utility's transmission tariff. However, FERC has already established that the Commission has jurisdiction over the implementation of PURPA at the state level and as I previously noted, the Commission has already established a dispute resolution process for QFs in both Schedule 37 and Schedule 38 in Oregon. It seems that Mr. Skeahan is implying that the Commission's current dispute resolution process is insufficient or unsatisfactory.

Q. Do you agree with Mr. Lowe's recommendation to allow the QF to create a LEO if not all project information is provided to complete a draft contract?

A. No. Schedule 37 and the standard contracts approved by the Commission lay out all the necessary information required for the Company to draft a contract for the QF. The Schedule and the standard contract were vetted by parties and approved by the

[4] CREA/100, Hilderbarnd/17-20.

Commission, and meeting any and all project information requirements in the contract is necessary to complete a binding agreement for both parties. Regardless of whether avoided cost prices are about to change or not, drafting a half-baked and incomplete contract does not protect the Company's customers from future litigation with the QF because the QF had not provided complete documentation. It usually leads to contract amendments, disputes, and sometimes leads to a QF cancelling a contract or the Company putting a QF contract in default because the contract was rushed through the preparation process.

Q. Do you have other disagreements with Mr. Lowe's proposals?

A. Yes. Mr. Lowe proposes that a QF should be able to "lock in" certain avoided cost prices if there are disputes that cannot be resolved before an avoided cost update goes into effect. His proposal would allow QFs to unilaterally trigger a LEO (and lock in avoided cost prices on the cusp of a price revision) by claiming there are disputed contractual terms. The construct proposed by Mr. Lowe would encourage inefficient negotiations as QFs would have an incentive to find disputes in order to lock in stale prices.

Q. How should pricing issues be resolved if there are disputes between a QF and a utility during contract negotiations?

A. Rather than allowing a QF to unilaterally "lock in" avoided cost prices with a LEO claim before entering into the dispute resolution process, the Commission should determine the appropriate avoided cost price that should apply when it resolves the contractual dispute under the Schedule 37 or Schedule 38 dispute resolution process.

Q. Is the Company's proposal a better balance between QF rights and protecting customer interest?

A. Yes. The Company has proposed that the Commission set criteria for establishing a legally enforceable obligation using the milestone of the QF approving the final draft PPA as contemplated in B(5) on page 10 of Schedule 37. This step satisfies Schedule 37 as established by the Commission, demonstrates that the QF has provided all required contract inputs and exhibits and signed off on the final draft agreement, and commits the Company to the agreement for execution. The Company can then move forward to execute knowing the document is complete and will not require amending, thus protecting customers from future litigation and complaints due to contracts being executed that are inaccurate or incomplete.

Q. Mr. Lowe describes the contracting process as very one-sided process to the benefit of the utility and the utility forcing the QF to sign "illegal" contracts or agreements with unreasonable terms and conditions. Do you agree?

A. No I do not. Mr. Lowe seems to imply that the Company holds a bat over the head of the QF and forces them to execute radically different and illegal agreements. That is simply not the case. In fact, the Company has accommodated many changes through contract addendums for the benefit of the QF as well as addendums to clarify project situations that were not anticipated when the Schedule 37 contracts were developed and approved. Schedule 37 and the standard contracts are approved by the Commission for the purpose of having a standardized process for smaller QFs that may not have the resources to negotiate a contract. However, regardless of efforts of all parties and the Commission in docket UM 1129, one contract may not fit all QFs.

As pointed out by Commission staff, in UM 1129, a QF that qualifies for Schedule 37 standard contract can still have a negotiated contract that is a PURPA contract. And the Commission acknowledged that in Order No. 06-538, stating that a standard or negotiated contract is still a PURPA contract.[5]

Since 2008 when UM 1129 finished and the Schedule 37 contracts were finalized, those contract templates have had no updated terms or conditions until Schedule 37 was updated in August 2014 when the Company made minimal updates to the contracts to comply with the renewable avoided cost pricing. No other contract terms and conditions were updated beyond the inclusion of the renewable avoided cost price stream. During that time from 2008 to 2014 the Company executed over 75 standard contracts, most of which had no changes but the Company also allowed or requested changes through addendums to the contract to accommodate project specific characteristics requested by the QF, industry changes such as replacement of the market index, or a policy change implemented by the Company. The Company does acknowledge that it has requested addendums to standard PPAs based on changes in Company policies however, the Company would not have refused to execute a PPA if the QF had refused to sign the addendum. On the other hand, the Company has routinely accommodated changes requested by the QF. For example, the Company executed a standard contract with Oregon State University that accommodated restrictions on insurance and indemnification as a public agency to comply with Oregon law. The Company also executed several standard contracts with addendums for wind QFs that were sharing a common interconnection to accommodate the metering and allocation of station service and line losses between

[5] UM 1129, Order No. 06-538, page 44.

the projects on the common interconnection line. Unfortunately, a one-size contract does not fit all, and the Company has been fair in making accommodations to standard contracts for both the QF and the Company's customers. And if a QF is unhappy with the standard Commission-approved contract, it remains free to negotiate a different PURPA contract with the Company or seek resolution through the dispute resolution process under Schedule 37.

Q. Do you agree with Mr. Benga on his three circumstances to create a LEO?

A. No. While Mr. Benga's testimony is focused mainly on Idaho Power Company, the Company disagrees with Mr. Benga's position that a LEO is created if the utility has approved avoided costs, approved standard contracts, and the QF submits an application for the project based on the utility's rate schedule for QF purchases. Mr. Benga allows no time or process for the utility to even review the application to determine if it is complete. In practical effect, Mr. Benga's proposal would allow a QF to unilaterally establish a LEO by submitting an application, and utilities would have no opportunity to review them to ensure they are complete. While many applications contain all project information, it is my experience that some applications are not fully completed or correct; they may have incorrect energy production, wrong interconnection points, no FERC certification as a QF, etc. It is an important step in the contract process as the Commission has currently approved in the Company's Schedule 37 to allow for those checks and balances as the QF moves from application to contract execution.

Q. Does the QF have an alternate method for establishing a LEO outside of PacifiCorp's proposed process?

A. Yes, the QF always has the dispute resolution process as established in Schedule 37 and Schedule 38.

ISSUE 9: HOW SHOULD THIRD-PARTY TRANSMISSION COSTS MOVE TO QF OUTPUT IN A LOAD POCKET TO LOAD BE CALCULATED AND ACCOUNTED FOR IN THE STANDARD CONTRACT?

Q. Please summarize the Company's position in your direct testimony.

A. The Commission acknowledged that third party transmission cost as a result of a purchase by the utility to move a QF's output from a load pocket where the QF's generation exceeds the load to another load area on the utilities system is the responsibility of the QF. Any costs and benefits of third-party transmission service should be attributed to the individual QF and should be reflected as an adjustment to the avoided cost price or as a contractual adjustment to billing in the contract. As noted by the Commission in Order No. 14-058:

> In applying this principle here, we first conclude that our adopted method of determining avoided cost prices based on avoided proxy resources reflects full avoided costs. Second, we conclude that any third-party transmission costs incurred by a utility to move QF output from the point of delivery to load would be costs that are not included in the calculation of avoided cost rates in standard contracts, and therefore are costs that are additional to avoided costs. Third, we conclude that any costs imposed on a utility that are above the utility's avoided costs must be assigned to the QF in order to comport with PURPA avoided cost principles.[6]

Q. Has your position changed?

A. No.

[6] Docket UM 1610 Phase I, Order No. 14-058, February 24, 2014, p. 22.

Q. Is there some confusion by the parties regarding third party transmission costs in delivering the proxy resource to load as compared to QFs bearing the cost of third-party transmission when delivering generation out of a load pocket?

A. Yes. Mr. Skeahan argues that the Company is discriminating against QFs by requiring QFs to pay for third-party transmission but not including third party transmission cost for the proxy resource in its avoided cost. The Company's witness, Mr. Dickman, will address the proxy resource and transmission cost associated with serving load and I will speak specifically to the third-party transmission cost associated with moving QF generation in excess of load out of a load pocket over a non-PacifiCorp transmission provider.

Q. Please provide a refresher on the nature of the load pocket issue.

A. First let me attempt to define "load pocket" as it pertains to PacifiCorp. The Company's Oregon service territory is not one continuous system. Rather, it is composed of multiple allocated service territories across the state—some large, some small—all interconnected by transmission lines.

In some instances, the Company's transmission function (PacifiCorp Transmission) controls the transmission system interconnecting elements of the Company's larger system. In other cases, the Company purchases service across transmission owned by a third party in order to deliver (or export) generation to (or from) an isolated portion of its service territory to supply its retail load. And many of those same transmission providers also purchase transmission service from PacifiCorp Transmission to supply their own retail loads. Many of these agreements between PacifiCorp and the third-party transmission providers are legacy transmission agreements developed for the one-way delivery of power into an isolated pocket to serve retail load and not for exporting power out of the area where generation may exceed load. At the time these legacy agreements were prepared and executed, generation in rural areas was rare, and new generation sources such as wind and solar project development were not even on the horizon. The Company refers to these areas that are entirely or partially reliant on third-party transmission as *load pockets*.

The Company's load and resource balance within an Oregon load pocket can reflect a mix of conditions ranging from those load pockets with surplus internal generation to those with inadequate internal generation. Moreover, some load pockets exhibit seasonal variations between surplus and inadequate internal generation, relative to their loads. When new generation is interconnected to a load pocket and creates a surplus of local resources, then the Company must purchase transmission out of the load pocket if available or else curtail the local generation, to the extent the new generation exceeds local load and there is no available transmission to purchase. Thus, any time a new generator causes generation within a load pocket to exceed load, the Company will incur an additional cost to transmit the excess load pocket generation across third-party transmission to another area with load.

Q. Is a load pocket a dynamic situation?

A. Yes. Mr. Skeahan makes note of several data requests where the Company indicated that only three of 30 PPAs executed since June 2011 were in load pockets requiring the need for purchase of third party transmission. While the data requests reflected a snapshot in time, the addition of multiple solar QF PPAs in the past few months will only contribute to the expansion of the issue since the solar projects are generally built in rural areas and interconnected at distribution or sub-transmission voltage levels. And in some cases where the Company has been working with the multiple QF PPA requests, the exported excess generation causes the destination area to develop an excess condition. Likewise, if a large retail load comes on-line or expands, such as a data center, excess generation in the load pocket could be consumed by the new load, reshaping the timing and amount of excess generation for years to come.

Q. Does Mr. Skeahan's proposal to provide maps with designated load pockets and the available MWs in the load pocket make sense?

A. No, for a number of reasons. First, as I mentioned above, a load pocket is a dynamic situation, going up or down as load and generation is added or removed, so updating load pockets with every Schedule 37 update would be burdensome and likely not remain accurate for very long. Therefore, a QF making a decision based on the information from a map may be misinformed when it should be seeking the most accurate and up-to-date information from the utility.

Second, the merchant side of PacifiCorp, which manages the PPA process, relies on PacifiCorp Transmission to calculate the minimum load conditions in the load pocket and determine if excess generation will exist. PacifiCorp's merchant function only receives information that would be publically available on Open Access Same-time Information System (OASIS). PacifiCorp, in its merchant function, can use OASIS information to determine at a high level if the addition of a new generator will cause an excess condition but the Company has to comply with any Open Access

Transmission Tariff (OATT) requirements and cannot always determine the specific timing and amount of excess megawatt (MW) until it completes a transmission service request per the OATT. Third, the QF itself will receive some preliminary information regarding excess generation conditions and minimum loads when it conducts its interconnection studies through PacifiCorp Transmission.

Q. Can you respond to Mr. Skeahan's load pocket alternatives proposed for QFs?

A. Yes. I will attempt to address each one individually. On a general level, Mr. Skeahan suggests that the Company should notify the QF upfront and early in the contract process if there is a possibility of excess generation and what the impact is to the QF. The Company does attempt to do so once we have the project information, informing the QF as soon as practical if we anticipate any excess generation issues, however details on timing and amount of excess are not available to PacifiCorp merchant until a transmission service request is placed in accordance with PacifiCorp Transmission's OATT. In most cases, the QF will proceed with the high level information. The details of the third party transmission required are not available until PacifiCorp receives information on excess generation from PacifiCorp Transmission under its OATT and also contacts the third-party transmission provider through a transmission service request per that transmission provider's OATT.

Q. Do you agree with Mr. Skeahan's alternative to offer the QF a fixed avoided cost price reduction over the contract term based on the procurement of long term firm (LTF) point to point (PTP) transmission and refunding to the QF any redirected or sold excess transmission when generation is below load?

A. No. There are issues with this alternative. First, the fixed reduction does not take into account the changes in a third-party provider's OATT rates. Just as any tariff has prices changes, in order to pass through the most accurate cost to the QF, it should be based on actual costs incurred. Otherwise, the customers of the utility are exposed to undo price risk. Mr. Skeahan references TMF Biofuels as a QF that agreed to a fixed rate reduction. While it was not PacifiCorp's preferred option, at the time of the contracting process, the two parties negotiated to move the power purchase agreement (PPA) forward and agreed to the fixed rate reduction based on known as Bonneville Power Administration (BPA) OATT rates and an assumed escalation over the term, rather than litigate the costs.

Second, Mr. Skeahan suggests refunding of any sale of excess transmission service or redirecting of transmission service if generation is less than load. Unfortunately, the transmission path selected is generally out of a load pocket that is under a legacy transmission service agreement and has historically had no transmission service on it in both directions, i.e., the legacy transmission was to serve load and not to export. In that case, there are very limited parties, if any that would have an interest to purchase transmission service on that path. In other words, no other parties are in the transmission service queue to purchase PTP on the same path out of a load pocket. It is a very unique need applied to a specific situation.

Q. What is your response to Mr. Skeahan's second alternative of including a contract addendum for actual costs with a significant number of restrictions and documentation requirements?

A. While the Company agrees with the concept of using a contract addendum to capture actual costs and pass them through to the QF, Mr. Skeahan's proposal puts a significant burden on the utility and shifts the risk to the utility's customers. First, the sole purpose of the QF purchase by the Company is to serve its retail load on a firm basis. The Company and its customers should not bear the risk of inadequate or less than firm transmission service to move that resource to load. Firm point-to-point (PTP) transmission may be purchased on a short-term or long-term basis where short-term is for a month, a day, or even an hour, and long-term is for a minimum one year, but a minimum five-year commitment is required to obtain renewal rights for continuing service beyond the initial commitment.

Long-term firm (LTF) PTP is the only form of transmission service that provides the utility a dependable right to wheel surplus generation from a load pocket to the Company's larger system for the full term of a PPA. Short-term non-firm transmission may also be available but is not used for network load service because it is subject to displacement by other parties who have firm transmission or higher priority non-firm transmission.

In the event another transmission customer owns or purchases firm or higher priority non-firm transmission from the transmission provider across the same path, the third-party transmission provider will deny the lower priority non-firm transmission use if there is not enough capacity for all customer uses. Therefore, in order to ensure that firm third-party transmission service will remain available over the term of the PPA to serve retail load, the Company purchases long-term firm PTP transmission, if it is available. Long-term firm PTP transmissions provides QFs with assurances that transmission will be available, provides utilities with certainty that QF output will be reliability delivered, and provides customers with assurances that their loads will be met. Mr. Skeahan's proposal as presented could lead to disputes on decisions and possible litigation.

Q. What is your response on use of curtailment as an alternative to purchase of LTF PTP transmission service?

A. In light of FERC's decisions around curtailment of QFs for reliability issues only, PacifiCorp would not use curtailment as an alternative as suggested by Mr. Skeahan. As with his previous alternative, it places significant burden and risk on the Company and its customers as well as setting up situations that could lead to disputes and litigation.

Q. What amount of LTF PTP transmission should be purchased?

A. The simple answer is what is necessary on a long-term basis to export the excess generation from the load pocket. If it is the full name-plate capacity or a portion of it, then the Company would seek to secure that amount, however it would be done for the long-term to cover the term of the PPA and not on a short-term basis.

Ms. Broad points out that the Company did not secure the full amount of LTF PTP service for Threemile Canyon Wind nor did we initially purchase the long term product. That is correct on both. First, LTF PTP was not available from BPA at the time and it was several years before it was secured from BPA and then the Company was only awarded conditional firm. Second, the Company did not need the full nameplate for the project to export because a portion of the generation would be absorbed by the minimum load conditions in the load pocket. Any subsequent QF in the load pocket built after Threemile Canyon Wind would be required to secure LTF PTP for its full-name plate capacity because the minimum load became zero after

Threemile Canyon Wind.

In the case of the two solar QFs, Adams Solar Center and Elbe Solar Center, referenced by Ms. Broad, the QFs executed their PPAs with an addendum in each PPA allowing for the Company to acquire 10 MW of transmission service for each project out of the Madras load pocket, based on information available to the Company at the time of execution. The load pocket as currently served requires two wheels, one with PGE and one with BPA, to get any excess generation out of the load pocket to load. The Company subsequently through its transmission service request to PacifiCorp transmission, determined that only 14 MW of excess generation needed to be exported in accordance with minimum load requirements reported by PacifiCorp Transmission. Therefore, the Company sought LTF PTP transmission from PGE and BPA in the amount of 14 MW. The Company also was able to secure the BPA transmission service as short-distance service because of the transmission service was only across a BPA substation which is a 40 percent discount to full tariff rates. The Company was able to improve on the transmission service cost to benefit the QF while meeting its firm delivery obligation to its customers.

Q. Do you see much difference between an off-system QF delivering to PacifiCorp via LTF PTP and the use of that same product by PacifiCorp out of a load pocket for excess generation?

A. No. The use and acquisition of third party transmission are very similar on a physical delivery basis. An off-system QF is required to demonstrate it can deliver its generator output to PacifiCorp's system via long-term firm point-to-point transmission such that PacifiCorp in its merchant function receives it on a firm scheduled basis and can seek network resource designation of that QF resource to serve its retail load on its system. In that case, the QF goes to the third party transmission service provider to acquire LTF PTP transmission and any ancillary services for the term of the PPA to meet its firm delivery obligation. Those costs are borne by the QF.

In the load pocket situation where there is excess generation, the utility has already received the generator output directly from the QF but must transport the excess generation via a third-party transmission service provider to another location to supply its retail load. In this excess generation case, the Company's merchant function, in order to secure network resource designation from PacifiCorp Transmission for the QF resource must demonstrate to PacifiCorp Transmission it has acquired long term firm point to point transmission from the third party transmission provider. In accordance with the Commission's order in Phase I, the cost of the third-party transmission service to move the excess generation is borne by the QF. Thus, in both cases, in order for the Company to secure network designation of the QF resource, long-term firm point-to-point transmission service is necessary to move the resource to load and the cost responsibility associated with that transmission service is assigned to the QF.

Q. Do you agree with Mr. Lowe's recommendation on third-party transmission service?

A. Not entirely. Mr. Lowe suggests that existing and new QFs should be treated differently. In fact they are. An existing QF in a load pocket already has network transmission service and is accounted for in minimum load conditions by PacifiCorp

Transmission when a new QF is added. That would continue for the long-term even when the QF's existing contract expired because the QF already has network resource designation and would continue uninterrupted with the next PPA unless the QF shut down permanently. In the situation where load has dropped significantly and the QF upon PPA renewal is now in excess of load then the QF would be responsible of the cost of transmission service. In all cases, PacifiCorp merchant must comply with PacifiCorp Transmission's OATT whether it is regarding new QFs or existing QFs.

I also do not agree with his position regarding the use of non-firm or any lesser quality product than LTF PTP. That simply shifts the risk to the customer of not having resources to serve load. As I have discussed above relative to other parties, in order to ensure that firm third-party transmission service will remain available over the term of the PPA to serve retail load, the Company purchases long-term firm PTP transmission, if it is available. It assures the QF of no transmission service issues and a certainty to our customers of resources to meet their load.

Q. Can you summarize your proposal associated with third-party transmission service as accounted for in the standard contract?

A. The costs and benefits of third-party transmission should not be incorporated into the actual calculation of the standard avoided cost; rather the costs and benefits should be captured on an individual QF project basis in the contract between the QF and Company as an addendum to the agreement. This is necessary because each project will be unique based on geographical location and the local electrical system loads and resources. The Company would secure LTF PTP to deliver the excess generation of the minimum load conditions to load elsewhere on the Company's system.

Q. Does this conclude your response testimony?

A. Yes.