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August 20, 2019

Via Electronic Filing

Public Utility Commission of Oregon
Attn: Filing Center
PO Box 1088
Salem, OR 97308-1088

Re: UM 1971 - Waconda Solar, LLC v. Portland General Electronic Company

Attention Filing Center:

Enclosed for filing today in the above-named docket is Molly Honoré's Declaration in Support of Portland General Electric Company's Second Motion for Summary Judgment.

Thank you for your assistance.

Very truly yours,

Jeffrey S. Lovinger

901666

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1971

WACONDA SOLAR, LLC, Complainant, vs. PORTLAND GENERAL ELECTRIC COMPANY, Defendant.	**DECLARATION OF MOLLY K. HONORÉ IN SUPPORT OF PORTLAND GENERAL ELECTRIC COMPANY'S SECOND MOTION FOR SUMMARY JUDGMENT**

I, Molly K. Honoré, declare:

1. I am defendant's attorney, and I make this declaration in support of Portland General Electric Company's ("PGE") Second Motion for Summary Judgment. The following statements are true and correct and, if called upon, I could competently testify to the facts averred herein.

2. Attached as **Exhibit 1** is a true and accurate copy of excerpts of Standardization of Generator Interconnection Agreements and Procedures, 104 FERC ⁋ 61,103, 18 CFR Part 35, Order No. 2003 at 13 (July 24, 2003). This document is also available at https://www.ferc.gov/legal/maj-ord-reg/land-docs/order2003.asp.

3. Attached as **Exhibit 2** is a true and accurate copy of *In the Matter of a Rulemaking to Adopt Rules Related to Small Generator Interconnection,* Docket No. AR 521, Staff Second Set of Comments Workshop Edits (Oct. 10, 2007).

4. Attached as **Exhibit 3** is a true and accurate copy of *In the Matter of a Rulemaking to Adopt Rules Related to Small Generator Interconnection*, Docket No. AR 521, Comments of Sorenson Engineering, Inc. (Nov. 27, 2007).

5. Attached as **Exhibit 4** is a true and accurate copy of *In the Matter of a Rulemaking to Adopt Rules Related to Small Generator Interconnection*, Docket No. AR 521, Comments of Energy Trust of Oregon, Inc. (Nov. 9, 2007).

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6. Attached as **Exhibit 5** is a true and accurate copy of *In the Matter of a Rulemaking to Adopt Rules Related to Small Generator Interconnection,* Docket No. AR 521, PGE's Comments (Nov. 27, 2007).

7. Attached as **Exhibit 6** is a true and accurate copy of *In the Matter of Public Utility Commission of Oregon, Staff Investigation Into Qualifying Facility Contracting and Pricing,* Docket No. UM 1610, Staff's Proposed Issues List (Oct. 3, 2012).

8. Attached as **Exhibit 7** is a true and accurate copy of *In the Matter of Public Utility Commission of Oregon, Staff Investigation Into Qualifying Facility Contracting and Pricing,* Docket No. UM 1610, Renewable Energy Coalition's Response to Disputed Issues (Oct. 10, 2012).

9. Attached as **Exhibit 8** is a true and accurate copy of *In the Matter of Public Utility Commission of Oregon, Staff Investigation Into Qualifying Facility Contracting and Pricing,* Docket No. UM 1610, Administrative Law Judge's Ruling (Oct. 25, 2012).

10. Attached as **Exhibit 9** is a true and accurate copy of an excerpt of *In the Matter of Public Utility Commission of Oregon, Staff Investigation Into Qualifying Facility Contracting and Pricing,* Docket No. UM 1610, Staff's Response to Disputed Issues (Oct. 10, 2012).

11. Attached as **Exhibit 10** is a true and accurate copy of an excerpt of *In the Matter of Public Utility Commission of Oregon, Staff's Investigation Relating to Electric Utility Purchases from Qualifying Facilities,* Docket No. UM 1129, Order No. 05-584 (May 13, 2005).

I hereby declare that the above statement is true to the best of my knowledge and belief, and that I understand it is made for use as evidence in court and is subject to penalty for perjury.

DATED this 20th day of August, 2019.

Molly Honoré

Molly K. Honoré, OSB #125250

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104 FERC ¶ 61,103

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 35

[Docket No. RM02-1-000; Order No. 2003]

Standardization of Generator Interconnection Agreements and Procedures

(Issued July 24, 2003)

AGENCY: Federal Energy Regulatory Commission

ACTION: Final Rule

SUMMARY: The Federal Energy Regulatory Commission (Commission) is amending its regulations under the Federal Power Act to require public utilities that own, control, or operate facilities for transmitting electric energy in interstate commerce to file revised open access transmission tariffs containing standard generator interconnection procedures and a standard agreement that the Commission is adopting in this order and to provide interconnection service to devices used for the production of electricity having a capacity of more than 20 megawatts, under them. Any non-public utility that seeks voluntary compliance with the reciprocity condition of an open access transmission tariff may satisfy this condition by adopting these procedures and this agreement.

EFFECTIVE DATE: This Final Rule will become effective [insert date that is 60 days after publication in the FEDERAL REGISTER.]

FOR FURTHER INFORMATION CONTACT:

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SUPPLEMENTARY INFORMATION:

32. In Part C, we discuss a number of other significant policy issues in connection with this rulemaking, including pricing policies; the required Interconnection Services; the treatment of "Distribution" level interconnections; Qualifying Facility matters; variations from the Final Rule and accommodation of regional differences; the availability of waivers for small entities; OATT reciprocity implications for interconnection requests; assorted clarifications to the NOPR's proposals; insurance and liquidated damages matters; two- versus three party interconnection agreements; and consequential damage issues.

33. In Part D, we address Compliance Issues pertaining to the requirement for a Transmission Provider to file conforming amendments to its existing OATT; the treatment to be accorded existing interconnection agreements (grandfathering); and the method a Transmission Provider is to use to file executed and unexecuted interconnection agreements in accord with this Final Rule.

A. Issues Related to the Standard Large Generator Interconnection Procedures (LGIP)

1. Overview[34]

34. The Final Rule Standard Large Generator Interconnection Procedures (LGIP) document specifies the steps that must be followed and deadlines that must be met when an Interconnection Customer requests interconnection of either a new Generating Facility or the expansion of an existing Generating Facility with the Transmission Provider's Transmission System.[35] The Commission directs each public utility to amend its OATT with a single compliance filing to incorporate the Final Rule LGIP and the Standard Large Generator Interconnection Agreement (LGIA) documents. RTOs and ISOs must also make compliance filings, but as discussed above, will have more flexibility to propose different procedures and a different agreement.

35. The Final Rule LGIP sets forth the following steps to secure an interconnection. First, the prospective Interconnection Customer will submit an Interconnection Request to the Transmission Provider along with a $10,000 deposit, preliminary site documentation, and the expected In-Service Date.[36] The Transmission Provider will acknowledge receipt of the request and promptly notify the Interconnection Customer if its request is deficient. When the Interconnection Request is complete, the Transmission

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[34] For the convenience of the reader, a flow chart depicting the interconnection process is appended to this preamble as Appendix A.

[35] Any Transmission Provider with an Interconnection Request outstanding at the time this Final Rule becomes effective shall transition to the Final Rule LGIP within a reasonable period of time. This is further described in Final Rule LGIP Section 5.1.

[36] The standard form of Interconnection Request is Appendix 1 of the LGIP document.

Provider will place it in its interconnection queue with other pending requests. The Transmission Provider will assign a Queue Position to each completed Interconnection Request based on the date and time of its receipt.[37] Queue Position is used to determine the order of performing the various Interconnection Studies and the assignment of cost responsibility for the construction of facilities necessary to accommodate the Interconnection Request.[38] The Transmission Provider will also maintain a list of all Interconnection Requests[39] on its OASIS.[40]

36. The Parties will then schedule a Scoping Meeting to discuss possible Points of Interconnection and exchange technical information, including data that would reasonably be expected to affect such interconnection options.[41] The Scoping Meeting is followed by a series of Interconnection Studies to be performed by, or at the direction of, the Transmission Provider to evaluate the proposed interconnection in detail, identify any Adverse System Impacts on the Transmission Provider's Transmission System or Affected Systems, and specify the facility modifications that are needed to safely and reliably complete the interconnection.[42] These studies include:

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[37] For example, the first complete Interconnection Request, assigned an earlier Queue Position, is "higher-queued" relative to the second complete Interconnection Request that is assigned a later Queue Position and is "lower queued." The withdrawal of a complete Interconnection Request causes it to lose its Queue Position and all succeeding complete Interconnection Requests to advance, accordingly.

[38] Any Interconnection Customer assigned a Queue Position before the effective date of this Final Rule would retain that Queue Position.

[39] We emphasize that the Final Rule LGIP requires the Transmission Provider, the Transmission Owner, and such entities' officers, employees, and contractors to maintain proper procedures for Confidential Information provided by an Interconnection Customer related to the Interconnection Request, the disclosure of which could harm or prejudice the Interconnection Customer or its business.

[40] Open Access Same-Time Information System and Standards of Conduct, Order No. 889, 61 FR 21737 (May 10, 1996), FERC Stats. & Regs. ¶ 31,035 at 31,590 (1996), order on reh'g, Order No. 889-A, 62 FR 12484 (Mar. 14, 1997), FERC Stats. & Regs. ¶ 31,049 (1997), reh'g denied, Order No. 889-B , 81 FERC ¶ 61,253 (1997), aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC, 225 F.3d 667 (D.C. Cir. 2000), aff'd sub nom. New York v. FERC, 535 U.S. 1 (2002).

[41] The Scoping Meeting will address technical matters such as facility loadings, general instability issues, general short-circuit issues, general voltage issues, and general reliability issues that would affect the Interconnection Customer's designation of its Point of Interconnection.

[42] The standard forms of agreement for the Interconnection Feasibility Study, the Interconnection System Impact Study, the Interconnection Facilities Study, and the (continued...)

(1) Interconnection Feasibility Study to evaluate on a preliminary basis the feasibility of the proposed interconnection, using power flow and short-circuit analyses (to be completed within 45 Calendar Days from the date of signing of an Interconnection Feasibility Study Agreement) (study requires a $10,000 deposit);

(2) Interconnection System Impact Study to evaluate on a comprehensive basis the impact of the proposed interconnection on the reliability of Transmission Provider's Transmission System and Affected Systems, using a stability analysis, power flow, and short-circuit analyses (to be completed within 60 Calendar Days from the date of signing of an Interconnection System Impact Study Agreement) (study requires a $50,000 deposit);[43]

(3) Interconnection Facilities Study to determine a list of facilities (including Transmission Provider's Interconnection Facilities and Network Upgrades as identified in the Interconnection System Impact Study), the cost of those facilities, and the time required to interconnect the Generating Facility with the Transmission Provider's Transmission System (to be completed within 90-180 Calendar Days from the date of signing of an Interconnection Facilities Study Agreement) (study requires a $100,000 deposit or an estimated monthly cost developed by the Transmission Provider for conducting the Interconnection Facilities Study); and

(4) Optional Interconnection Study or sensitivity analysis of various assumptions specified by the Interconnection Customer to identify any Network Upgrades that may be required to provide transmission delivery service over alternative transmission paths for the electricity produced by the Generating Facility and (study requires a $10,000 deposit).

37. The Interconnection Feasibility Study, the Interconnection System Impact Study, and the Interconnection Facilities Study must be performed in the above order, with completion of each study before the next begins.[44] An Interconnection Customer may

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[42](...continued)
Optional Interconnection Study, are included at Appendices 2-4 to the Final Rule LGIP, respectively.

[43]At the Transmission Provider's option, Interconnection System Impact Studies for multiple Generating Facilities may be conducted serially or in clusters.

[44]These Interconnection Studies are typical of the kinds of studies undertaken by Transmission Providers to evaluate Interconnection Requests. The Interconnection Facilities Studies and Interconnection System Impact Studies also correspond to transmission service studies described in the pro forma open access tariff. See Order No. 888-A (Tariff Part II, 19 Additional Study Procedures For Firm Point-To-Point (continued...)

also request a restudy of any of the above if a higher-queued project either drops out of the queue, is subjected to Material Modifications, or changes its Point of Interconnection.[45] The Interconnection Customer will pay the actual costs for performing each of the Interconnection Studies and restudies.

38. The Transmission Provider's Interconnection Facilities Study report[46] will include a best estimate of the costs to effect the requested interconnection which are to be funded up-front by the Interconnection Customer. At the same time as the report is issued, the Transmission Provider shall also give the Interconnection Customer a draft interconnection agreement completed to the extent practicable.[47] The Transmission Provider and the Interconnection Customer will then negotiate the schedule for constructing and completing any necessary Transmission Provider Interconnection Facilities and Network Upgrades, and incorporate this schedule into the interconnection agreement that is signed by the Parties.[48]

2. Section-by-Section Discussion of the Proposed LGIP

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[44](...continued)
Transmission Service Requests; and Tariff Part III, 32 Additional Study Procedures For Network Integration Transmission Service Requests), FERC Stats. & Regs., Regulations Preambles (July 1996-December 2000), ¶ 31,048 at 30,524-26 and 30,535-36.

[45]An Interconnection Feasibility Restudy must be completed within 45 Calendar Days of such request. Similarly, the Transmission Provider has 60 Calendar Days to complete either an Interconnection System Impact Restudy or an Interconnection Facilities Restudy.

[46]Upon the completion of each of the Interconnection Studies, a report is prepared which presents the results of the analyses.

[47]The draft interconnection agreement shall include: Appendix A, Interconnection Facilities, Network Upgrades and Distribution Upgrades; Appendix B, Milestones; Appendix C, Interconnection Details; Appendix D, Security Arrangements Details; Appendix E, Commercial Operation Date; and Appendix F, Addresses for Delivery of Notices and Billings.

[48]In general, the In-Service Date of an Interconnection Customer's Generating Facility or Generating Facility expansion will determine the sequence of construction of Network Upgrades. An Interconnection Customer, in order to achieve its expected In-Service Date, may request that the Transmission Provider advance the completion of Network Upgrades necessary to support such In-Service Date that would otherwise not be completed pursuant to a contractual obligation of an entity other than the Interconnection Customer. The Transmission Provider will use Reasonable Efforts to advance the construction if the Interconnection Customer reimburses it for any associated expediting costs and the cost of such Network Upgrades. The Interconnection Customer is entitled to transmission credits for the expediting costs that it pays.

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

AR 521

In the Matter of a Rulemaking to Adopt	)	
Rules Related to Small Generator	)	STAFF COMMENTS
Interconnection.	)	

Staff Second Set of Comments

Workshop Edits

Staff has revised the Draft Rules and associated Forms based on the input of Participants at the September 25 AR 521 Workshop. In the attached documents the modifications are indicated using strikethrough and highlights. This represents Staff's best effort to capture omissions, mistakes and revisions discussed at the workshop. Staff does not attempt to discuss all the revisions made in these brief comments. Rather Participants are encouraged to review the draft Rules and Forms and consider the changes in the context in which they were made. Included with the revised Rules and Forms is an AR 521 Rulemaking Schedule indicating activities and dates discussed at the workshop. Although comments will be received at any time during the rulemaking, participants are encouraged to make comments on the recent workshop and the current draft Rules and Forms by October 16, 2007. Any comments submitted to the OPUC filing center for Docket AR 521 will be posted and available for all participants to review.

Thanks to all the participants to the recent workshop for their suggestions and comments. This concludes Staff's second set of comments.

Respectfully submitted,

Ed Durrenberger
Senior Utility Analyst
Electric & Natural Gas Division
Resource & Market Analysis

deficiencies. The Parties may mutually agree to extend the time period for resolving any deficiencies. If the Applicant fails to resolve the deficiencies to the satisfaction of the EDC within the agreed upon time period, the Application is deemed withdrawn.
(8) Operation: The Applicant must notify the EDC prior to commencing operation and must operate the Small Generator Facility in accordance with the executed Interconnection Agreement.

Stat. Auth.: ORS Ch. 183, 756 & 757
Stats. Implemented: ORS 756.040 & 756.060
Hist.: NEW

OAR 860-082-0055
Tier 4 Interconnection
(1) Applicability: The EDC must use the Tier 4 interconnection review procedures for an Application that does not qualify for Tier 1, Tier 2, or Tier 3 review and for which the Small Generator Facility has an Electric Nameplate Capacity that is 10 MW or less.
(2) Approval: The EDC must approve interconnection under the Tier 4 interconnection review procedure set forth in section (3) and studies set forth in sections (4) through (6) of this rule. The EDC may not impose requirements in addition to those set forth in the OSGIR.
(3) Tier 4 Interconnection Review Procedure:
(a) The Applicant must submit its Application and appropriate fees to the EDC at its designated address. The Application form is available on the Commission web site as Form 2.
(b) The EDC must, within 10 business days of receipt of the Application, inform the Applicant that the Application is either complete or incomplete. If the application is incomplete, the EDC must indicate what information is missing. In the event the Applicant does not receive notification within 10 business days, the Applicant may contact the EDC to determine the status of the Application.
(c) If the EDC does not have a record of receipt of the Application, the Applicant must provide the EDC with an additional copy of the Application. If the Applicant can demonstrate that the original completed Application was delivered to the EDC, the EDC must forgo the initial 10 business day response period and complete its review within 20 business days of its receipt.
(d) Queuing Priority: Once the EDC deems the Application to be complete, it must assign the project a Queue Position unless a queue position was already assigned under a previous lower-Tier Application that was not approved. The Queue Position of each Application is used to determine any potential Adverse System Impacts of the proposed Small Generator Facility based on the relevant data contained in the Application, the outcomes of the various studies and the Applicant's desired interconnection location. The Applicant must proceed under the timeframes of this section. The EDC must schedule a Scoping Meeting to notify the Applicant about other higher-queued Applications including, but not limited to, Net Metering Facility Applications and FERC Interconnection Applications on the same radial line or Area Network to which the Applicant is seeking to interconnect.

(e) If in the process of evaluating the completed Application ~~interconnection request~~, the EDC determines that supplemental or clarifying information is required, the EDC must request the information. The time required for the receipt of the additional information may extend the time before the Scoping Meeting can be convened but only to the extent of the time required for the receipt of the additional information. The EDC may not alter the Applicant's Queue Position. Supplemental or clarifying information can be provided in the scoping meeting.
(f) Studies: By mutual agreement of the Parties, the Scoping Meeting, Interconnection Feasibility Study, Interconnection Impact Study, or Interconnection Facilities Studies (or any combination thereof) as set forth in these Tier 4 procedures may be waived.
(g) Scoping Meeting: A Scoping Meeting must be held within 10 business days, or as agreed upon by the Parties, after the EDC has notified the Applicant that the Application is deemed complete. The purpose of the meeting is to review the Application including any existing studies relevant to the Application, (such as the results from the Tier 1, Tier 2 or Tier 3 screening criteria and studies or, if available, the Applicant's analysis of the proposed interconnection using the same criteria as the EDC applies to the Application). Parties are expected to bring to the Scoping Meeting such personnel, including system engineers and other resources, as may be reasonably required to accomplish the purpose of the meeting. Some Scoping Meeting outcomes may include:
(A) An identification of the need for further studies as described in sections (4), (5) and (6) of 860-082-0055 ~~this rule~~;
(B) Possible changes or modifications to the Application to facilitate the interconnection or reduce costs; or
(C) No changes at all and the EDC being able to proceed with the application without further studies.
In any case, where changes result from the scoping meeting, the Applicant maintains the assigned queue position so long as the additions or changes to the Application can be rectified within a 10 business day window, or a period mutually agreed upon by parties, from the date of notification.
(h) If the Parties agree at the Scoping Meeting that an Interconnection Feasibility Study needs to be performed, the EDC has up to 15 business days to complete an Interconnection Feasibility Study Agreement that provides the Applicant with an outline of the scope and a good faith, non-binding estimate of the cost to perform the study. A model form of an Interconnection Feasibility Study Agreement is provided on the Commission's website.
(4) Interconnection Feasibility Study:
(a) If the Applicant agrees to the cost estimate, the EDC must perform an Interconnection Feasibility Study. The study must evaluate the effects of the proposed Small Generator Facility on the existing EDC's T&D System and look for possible Adverse System Impacts. Some Feasibility Study outcomes may include:
(A) Initial identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;
(B) Initial identification of any thermal overload or voltage limit violations resulting from the interconnection;
(C) Initial review of grounding requirements and system protection; and

(D) Description and estimated cost of Interconnection Facilities and System Upgrades required to interconnect the Small Generator Facility to the EDC in a safe and reliable manner.
(b) If the Applicant asks that the Interconnection Feasibility Study evaluate multiple potential points of interconnection, the EDC will perform the additional evaluations at the Applicant's expense.
(c) If the Interconnection Feasibility Study identifies possible Adverse System Impacts from the Small Generator Facility, an Interconnection System Impact Study is required. The EDC has up to 15 business days to complete an Interconnection System Impact Study Agreement that provides the Applicant with an outline of the scope and a good faith, non-binding estimate of the cost to perform the study. A model form of an Interconnection System Impact Study Agreement is provided on the Commission's website.
(5) Interconnection System Impact Study:
(a) If the Applicant agrees to the cost estimate, the EDC must conduct an Interconnection System Impact Study. The study must evaluate the Adverse System Impacts identified in the Interconnection Feasibility Study, and study other potential impacts including, but not limited to, those identified in the Scoping Meeting.
(b) The study must consider all generating facilities that, on the date the Interconnection System Impact Study is commenced:
(A) Are directly interconnected with the EDC's system;
(B) Have a pending higher Queue Position to interconnect to the system; or;
(C) Have a signed Interconnection Agreement.
(c) The study must include, among other things:
(A) A short circuit analysis,
(B) A stability analysis,
(C) A power flow analysis,
(D) Voltage drop and flicker studies,
(E) Protection and set point coordination studies, and
(F) Grounding reviews.
(d) The Interconnection System Impact Study must:
(A) State the underlying assumptions of the study,
(B) Show the results of the analyses, and
(C) List any potential impediments to providing the requested interconnection service.
(e) If the Applicant sponsored a separate independent impact study, the EDC must also evaluate and address any alternative findings from that study.
(f) The outcome of the System Impact Study must include a report of any Interconnection Facilities and System Upgrades to the EDC's T&D system and any System Upgrades to Affected Systems required to allow the proposed interconnection to occur including an estimate of the equipment costs and standard delivery schedules.
(g) If Interconnection Facilities are found to be necessary in the System Impact Study, the EDC must determine the price and delivery of the facilities. The EDC has up to 15 business days after completion of the Interconnection System Impact Study, or a period mutually agreed upon by parties, to develop an Interconnection Facilities Study Agreement that provides the Applicant with the scope and a good faith, non-binding estimate of the cost to

perform the study. A model form of an Interconnection Facilities Study Agreement is provided on the Commission's website.
(6) Interconnection Facilities Study:
(a) If the Applicant agrees to the cost estimate, an Interconnection Facilities Study must be performed by the EDC to evaluate the cost of equipment, and the engineering, procurement and construction work (including overheads) needed to implement the conclusions of the Interconnection Feasibility Study and Interconnection System Impact Study for interconnection of the proposed Small Generator Facility. The Interconnection Facilities Study must also identify:
(A) The electrical switching configuration of the equipment, including, without limitation, transformer, switchgear, meters, and other station equipment;
(B) The nature and estimated cost of the EDC's Interconnection Facilities;
(C) System Upgrades required at the EDC and on Affected System that are necessary to accomplish the interconnection; and
(D) A detailed estimate of the time required to procure materials and equipment and complete the construction and installation of such facilities.
(b) Parties may agree to permit the Interconnection Customer to separately arrange for a third party to design and estimate the construction costs for the required Interconnection Facilities. In such a case, the EDC must review the design and cost estimates of the facilities, under the provisions of the Interconnection Facilities Study Agreement. If the Parties agree to separately arrange for design and construction estimates, and comply with any security and confidentiality requirements, the EDC must make all relevant information and required specifications available to the Applicant at no cost in order to permit the Applicant to obtain an independent design and cost estimate for the facilities, to be built in accordance with such specifications.
(7) Approval: Upon completion of the Interconnection Facilities Study, and with the agreement of Applicant to pay for necessary Interconnection Facilities and System Upgrades identified in the Interconnection Facilities Study as approved by the EDC, and provided the EDC determines, based in the studies in 860-082-0055 (4) through (6) ~~of this rule~~, that safety and reliability will not be compromised from interconnecting the Small Generator Facility, the EDC must approve the application
(a) The interconnection customer must provide the EDC at least 20 days notice of the planned commissioning for the small generator facility.
(b) The EDC has the option of conducting a witness test at a mutually agreeable time within 10 business days of the scheduled commissioning or waiving the test and notifying the Applicant. If the EDC does not conduct the witness test within the 10 business days or within the time otherwise mutually agreed upon by the parties, or if the EDC notifies the Applicant of its intent not to perform the test, the witness test is deemed waived.
(8) Non-Approval: If the Application is denied, the EDC must provide a written explanation explaining why the Application was denied.
(9) Interconnection of the Small Generator Facility: The Interconnection is not final until:
(a) Any facilities and upgrades agreed upon in sections (3) through (6) are satisfied;
(b) The Small Generator Facility installation is inspected and approved by the electric code inspector with jurisdiction over the interconnection;
(c) The Parties execute a Certificate of Completion; and

(d) There is a successful completion of the Witness Test, if conducted by the EDC.
(10) Witness Test Not Acceptable: If the Witness Test is conducted and is not acceptable to the EDC, the Applicant must be allowed a period of 30 calendar days to resolve any deficiencies. The Parties may mutually agree to extend the time period for resolving any deficiencies. If the Applicant fails to resolve the deficiencies to the satisfaction of the EDC within the agreed upon time period, the Application is deemed withdrawn. The Applicant has the right to submit a new Interconnection Request for consideration at a later time but relinquishes the current Small Generation Facility's position in the queue.
(11) Operation: The Applicant must notify the EDC prior to commencing operation and must operate the Small Generator Facility in accordance with the executed Interconnection Agreement and the executed Power Purchase Agreement.

Stat. Auth.: ORS Ch. 183, 756 & 757
Stats. Implemented: ORS 756.040 & 756.060
Hist.: NEW

860-082-0060
Recordkeeping and Reporting Requirements
(1) The EDC must maintain, for a period of not less than two years, a record of all Applications received, the time required to complete its review of each Application, and reasons for the actions taken on the Applications.
(2) The EDC must maintain, for as long as the interconnection is in place, a record of all Interconnection Agreements completed and including the related "As Built" Form 7 that records equipment specifications and initial settings. The utility must provide a copy of these records to the Applicant or Interconnection Customer within 15 business days upon receipt of a written request.
(3) The EDC must prepare and submit to the Commission, an annual report summarizing the EDC's interconnection activities including, but not necessarily limited to, the following information:
(a) For all Tiers of Interconnection Applications:
(A) The number Interconnection Applications made,
(B) The number of interconnections established,
(C) The individual types of generators applying for interconnection and their capacity,
(D) Interconnection Application location by Zip code, and
(E) A report of any disputes and their resolution.
(b) For Tier 2 through Tier 4 Interconnection Applications:
(A) Estimated facilities costs from studies,
(B) Whether telemetry is required and if so, its basic configuration, and
(C) System upgrades required and their estimated costs.
(c) For all applications that led to successful interconnections:
(A) Whether or not timelines were met and if not an explanation of why they were not met, and
(B) A record of any item(s) that Parties mutually agreed to waive.

Stat. Auth.: ORS Ch. 183, 756 & 757

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Attorneys for Sorenson Engineering, Inc.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

IN THE MATTER OF RULEMAKING TO ADOPT RULES RELATED TO SMALL GENERATOR INTERCONNECTION	CASE NO. AR 521 COMMENTS OF SORENSON ENGINEERING, INC.

COMES NOW, Sorenson Engineering, Inc. ("Sorenson") by and through its attorney of record, Peter J. Richardson, and pursuant to the schedule established by the Administrative Law Judge in the above captioned matter and hereby lodges its Comments to the Commission Staff's proposed rules and forms.

I

INTRODUCTION

Sorenson is an engineering firm with offices located in Idaho Falls, Idaho. It is a successful engineer, developer, owner and operator of numerous small power production facilities. Sorenson Engineering is working with or is in the planning stages of developing similar projects in Oregon. Sorenson has many years of experience in the subject matter of this proceeding. Sorenson's comments have been prepared with the expert assistance of Mr. John Lowe, who has many years of experience in facilitating the interconnection of small power production facilities to the electric system of investor-owned utilities. Sorenson appreciates the opportunity to comment herein and applauds this Commission's efforts to make the interconnection and operation of small power production facilities in Oregon a transparent, efficient and safe transaction.

II

INTERCONNECTION FACILITIES O&M REIMBURSEMENT

Interconnection costs include both initial costs to study and interconnect a generating project ("Interconnection Customer") as well as ongoing costs to operate and maintain both the project's interconnection equipment and the Public Utility's Interconnection Facilities. The Interconnection Customer is responsible for all these costs. The proposed rule AR-521 ("Rule") emphasizes the process of interconnect study and initial interconnection. The Rule should provide both the Public Utility and the Interconnection Customer with assurances as to the timing, process and responsibilities of the parties in completing the study process and in managing or controlling the cost of such studies. The Rule also addresses interconnection standards and provides an excellent basis by which the interconnection requirements can be determined and the costs therefore controlled. However, the Rule does not adequately address the subject of operation and maintenance (O&M) costs of the Public Utility's Interconnection Facilities usually paid for by the Interconnection Customer in the form of an annual O&M reimbursement.

These annual reimbursements in total over the term of an agreement can be very significant and in most cases dwarf the actual study costs. This is particularly significant for distribution level interconnections where such reimbursement may be as much as 12% of the original total interconnection cost annually. Average system O&M costs for the Public Utility's distribution system in the State of Oregon is the derivation for the O&M percentage applied to distribution interconnections in Oregon.

The Rule and the proposed interconnection agreement is generally vague regarding the Interconnection Customer's obligations regarding O&M reimbursements. The historic method of using average system cost for distribution interconnections should be abandoned in favor of a method utilizing actual costs incurred by the Public Utility. This actual cost approach has several advantages because it: (1) aligns more closely with the underlying cornerstone of ratepayer neutrality, which is elemental to any PURPA transaction; (2) creates consistency between the transmission and distribution interconnection O&M reimbursements where a Public Utility may already be utilizing actual cost for transmission interconnections; (3) creates consistency among the Interconnection Facilities for an Interconnection Customer to the extent that certain elements of such Interconnection Facilities are anticipated to reimburse the Public Utility based upon actual O&M costs. (*See* PacifiCorp initial comments, page 6, Metering . . . "The Interconnection Customer should pay the actual cost of such metering and its maintenance"); (5) minimizes the significance of the actual original interconnection costs, especially when such costs may be disputable; (6) establishes consistent treatment of Interconnection O&M reimbursements among all Public Utilities operating in Oregon; and most importantly (7) it will likely result in a dramatic reduction in O&M reimbursements during the period when most Interconnection Customers are making debt payments usually for ten to twenty years. This is demonstrated by existing Interconnection Customers who have observed little need on the Public Utility's behalf to incur costs maintaining or replacing their Interconnection Facilities.

(A) SORENSON'S SPECIFIC RECOMMENDATIONS

Rule § 860-082-0010 – Definitions:

Add the following new definition:

"Actual Cost of Interconnection Facility Operation and Maintenance" means the total documentable cost of services provided by the Public Utility associated with maintaining and operating the Public Utility's Interconnection Facilities for a Small Generator Facility.

Rule § 860-082-0030:

Add the following language to the end of the paragraph (3) on Cost Responsibility:

The Interconnection Customer is also responsible for reimbursing the Public Utility for the Actual Cost of Interconnection Facility Operation and Maintenance (O&M) as further described in the Interconnection Agreement.

Form 8: Article; add the following language as a new paragraph

4.7 The Public Utility may bill the Interconnection Customer not more often than annually for the Actual Cost of Interconnection Facility Operation and Maintenance (O&M) for the previous year.

IV

INTERCONNECTION CUSTOMER'S OPTION TO PERFORM STUDIES, DESIGN, CONSTRUCT, OWN AND OPERATE INTERCONNECTION FACILITIES

The Interconnection Customer should be permitted to minimize potential interconnection costs and to maximize the financial benefits of self operation, maintenance, and ownership of faculties that may otherwise be Interconnection Facilities. Therefore, the Interconnection Customer should have the option -- provided in all circumstances that electrical system safety and reliable operations are not compromised; and provided further that the Interconnection Customer pays all appropriate costs -- to perform interconnection studies or portions thereof. The Interconnection Customer also should have the option to design, construct, own, operate and maintain electrical facilities necessary for the project which otherwise might be designed, constructed, owned, operated and maintained by the Public Utility as Interconnection Facilities. Typical examples would be a line extension to be located on property controlled or owned by the Interconnection Customer or a substation for the Small Generating Facility that has intermingled electrical facilities. The Rule anticipates the Interconnection Customer having the rights described above, but may not go far enough to encourage or facilitate the Interconnection Customer's option. Additionally, there may be circumstances within a Utility where design, construction, operation and maintenance of transmission extensions is a requirement of the Interconnection Customer, and in trying to create some uniformity, it would be appropriate for a distribution Interconnection Customer to have at least the option, but certainly not be foreclosed from the benefits by the Public Utility.

(A) SORENSON'S SPECIFIC RECOMMENDATIONS

Rule 860-082-0030, § (1) Study Costs:

Add the following language to the end of Paragraph (1)

The Interconnection Customer or Applicant shall have the option to perform studies or portions of studies through an agreed-upon third party consultant provided that the Interconnection Customer: (i) pays all appropriate costs incurred by the Public Utility; (ii) waives any timeframes in the Rule associated with that required study; and (iii) holds the Utility harmless.

Rule 860-082-0055

Tier 4 Interconnection, (6) Interconnection Facilities Studies, subparagraph (b). Delete the first sentence and replace it with the following:

The Interconnection Customer shall have the option of having an agreed-upon third party consultant design and estimate the construction costs for the required Interconnection Facilities.

Add to the end of the subparagraph (4) the following language:

The Interconnection Customer must waive the required timeframes associated with the Interconnection Facilities Study, and hold the Utility harmless with regard to its results.

Rule 860-082-0030: Cost Responsibilities, paragraph (3)

Revise this paragraph by adding the following language to the end of the paragraph:

The Interconnection Customer shall have the option to design, construct, own, operate and maintain certain electrical facilities, i.e. line extension, that otherwise may have been designated as Interconnection Facilities, provided such facilities are located on property owned or adequately controlled by the Interconnection Customer, are for the exclusive use of the Interconnection Customer, and the design and construction of such facilities have been reviewed and inspected by the Public Utility (or inspected and certified by a registered professional electrical engineer), and the Interconnection Customer pays all costs. Such facilities will be designated as Interconnection Equipment regardless of the location of the Interconnection Customer's metering.

V

METERING AND MONITORING

PacifiCorp's initial comments on page 6, Section 4 indicate that PacifiCorp believes that the requirement for telephonic access to its metering for the Interconnection Customer is appropriate. While this is a noble objective and one that utilizes technological advances and efficiencies, it dos not impact safety or reliability of the electrical system and adds an interconnection requirement or standard that could raise the overall Interconnection Facility's costs. Also, for small projects approximately 1,000 kW or less, this requirement could be especially burdensome if both cellular service or hardwire telephone system are unavailable. Many small facilities may not have the sophisticated communications equipment that larger facilities typically have for operational monitoring. The requirement is generally reasonable for those projects afforded low-cost access to cellular service but should not be an absolute requirement if an expensive extension of a hardwire system is the only alternative. The parties should have the flexibility to resolve the meter reading issue as creatively as necessary, provided that the Interconnection Customers pays all the costs. As long as the telephone access requirement is universal, it may cause some existing small projects to shut down operations or potential new projects to not be able to afford moving forward. Sorenson understands that creative alternatives to cellular/hardwire connections are already being utilized for some projects in Oregon.

An Interconnection Customer's obligation to provide and/or pay for a telemetry system should be limited to those circumstances or conditions on a Public Utility's system when the lack of such telemetry system would have negative impacts upon safety, reliability or efficient operations. The proposed 3 MW threshold for Tier 4 interconnections is a significant improvement over PacifiCorp's past threshold of 1 MW. However, the 3 MW threshold is not necessarily the appropriate threshold to be applied to all Public Utilities and may not be the appropriate value for <u>any</u> of the Public Utilities. For example, Sorenson Engineering is aware of at least two hydroelectric projects of 4 MW or greater that have been connected to PacifiCorp's distribution system for a least fifteen years where the required and installed telemetry has not been maintained and the potential data not utilized by PacifiCorp for a very long time. Each Public Utility should be required to provide the evidence supporting their telemetry needs and requirements. Telemetry data for existing projects connected to distribution systems is irregularly utilized and projects over 5 MW connected to distribution systems are very rare. Therefore, Sorenson recommends that the telemetry requirement for all distribution system interconnections be either eliminated or raised to 5 MW. Additionally and typically, the larger the project the easier to absorb telemetry expenses. The Commission should raise the telemetry threshold to 5 MW until such time that the Public Utilities demonstrate and provide evidence of their actual needs. Alternatively, the Commission should require the Public Utilities to provide evidence of their existing telemetry applications and demonstrate their usefulness. That is the only way to provide resolution of this controversial issue.

(A) SORENSON'S SPECIFIC RECOMMENDATIONS

Rule 860-082-0065: Metering and Monitoring, paragraph (1)

Revise paragraph (1) by adding the following language at the very end:

<u>The Interconnection Customer shall provide for remote or telephonic access of the Public Utility's metering either through cellular, hardwire or other technologically appropriate means except this requirement shall not apply to an Interconnection Customer who is operating or plans to operate a facility of 1,000 kW or less if such Interconnection Customer does not have cellular service available at the time of entering into the Interconnection Agreement.</u>

Rule 860-082-0065

Change the reference to 3 MW to 5 MW throughout this rule.

Respectfully submitted this 27th day of November 2007.

RICHARDSON & O'LEARY PLLC

By ______________________________
Peter J. Richardson
Attorneys for Sorenson Engineering, Inc.

CERTIFICATE OF SERVICE

I certify that I have caused to be servedd the foregoing Sorenson Engineering Comments in OPUC Docket No. AR 521 by electronic mail and first class mail to those who have not waived paper service on the attached service list. Dated this 27th day of November 27, 2007.

Peter Richardson OSB # 066687

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EnergyTrust of Oregon, Inc.

November 8, 2007

Ted Durrenberger
Oregon Public Utility Commission
Via email

Re: Draft Proposed Small Generator Interconnection Rules

Dear Ted,

Energy Trust appreciates the opportunity to comment on staff's draft small generator interconnection rules. We congratulate the OPUC staff for your work with all the stakeholders to develop these interconnection rules.

Energy Trust has supported numerous small generators as part of its mission to support new clean energy sources for customers of Pacific Power and Portland General Electric. We have found that interconnection procedures and requirements can easily become the most significant impediment to funding and completing projects.

With the passage of SB 838, Energy Trust now has a requirement to focus even more on small generator projects. Open, clear, fast and cost effective interconnections procedures and requirements will be critical to meeting goals for our revised focus. We have to recognize that burdening small generation with processes and costs similar to large projects will not help us reach the community energy goals in SB 838.

We offer the following comments, including suggested improvements for specific sections in the draft rules, as noted below:

<u>860-082-0005 (3)(b)(Scope and Applicability- unilateral timeline waiver)</u>

We request that the Public Utility not be allowed a unilateral waiver from the timelines set forth in the OSGIR and instead propose that the utility provide adequate staff resources or subcontract out the work to a third party. The demand for small generator interconnections will only increase in the future as developers respond to the community energy goals of SB 838 and it is the responsibility of the utility to respond in a timely fashion to interconnection requests.

860-082-0060 (Recordkeeping and Reporting Requirements)

We support the recordkeeping and reporting requirements as a set of valuable tools to add transparency of the process but are suggesting changes to further increase their value.

Knowing whether issues are repetitive allows improvements to be made to the rules. Further, it allows participants to see what solutions worked so the small generators can come in with the right solutions first or at least know what the acceptable solutions cost.

An issue we face today is the process always taking the maximum amount of time for each step, no matter how simple or complex the circumstance. It is also common for a utility to present very expensive upgrade requirements that require additional time to negotiate to a more acceptable solution. Negotiation timelines are not in the rules and can add considerable time to the process. The additional data points will help define whether additional rules are needed or situations are truly unique and separable.

In addition to the data requirements in the draft rules, we recommend adding the follow requirements for Tier 2 through Tier 4 Interconnection Applications:

- Actual facilities costs
- Actual system upgrades and costs
- Estimated telemetry basic configuration
- Actual telemetry basic configuration
- Estimated telemetry cost
- Actual telemetry cost
- Number of days to deliver each agreement
- The number of days to complete each study
- The number of days to complete the facility installation and system upgrades.

Due to the potential confidential nature of this data we suggest that 1) the interconnection customer be asked to waive this data for reporting purposes or 2) if they refuse, report it to the commission on a confidential basis for commission staff review.

With the proposed rules is the need for transparency to ensure non-discriminatory interconnection of small generators. To this end, we recommend a periodic review of interconnection applications with modifications to the small generation interconnection rules as necessary. The rules are inherently flexible due to the technical complexity of interconnection. With this flexibility comes the opportunity of abuse that can be addressed through periodic reporting and reviews of interconnection applications

860-082-0080 (Dispute Resolution)

We agree with the small generator community that a streamed-line arbitrator-based dispute resolution process is better than the more formal OPUC complaint process. OPUC staff has stated that this provision is not necessary and should be removed from the rules. Respectfully, we disagree. We recognize the desire to not reinvent the wheel and staffs and utility familiarity with today's procedure. However, longer, formal processes are time consuming and expensive. They put a disproportionate cost burden on small projects and can increase above-market costs. The process proposed by the small generator community appears to us faster, clear and cheaper. We appreciate that it remains in the draft rules allowing the topic to be aired in the rulemaking process.

860-082-055 (7) Approval

The proposed rules are silent about the time allowed for the construction of upgrades. The Applicant has no means to ensure the construction of the upgrades occurs in a reasonable timeframe as dictated by the scope of the construction. There needs to be an agreed period.

We suggestion additional language in this section to address this issue. The following points should be included:

1. The Public Utility and the Applicant will identify a mutually agreed timeline for the construction of the upgrades and the date that the system will be able to accommodate the project for witness testing, commissioning and operation.
2. If the Public Utility and the Applicant can not mutually agree to a timeline and cost, the applicant shall have the option to have the upgrades contracted to an independent contractor to obtain a more favorable timeline.

Form 4 (11-2 rev) Interconnection Facilities Study Form Agreement

Item 6 specifies a thirty calendar day study period when no upgrades are required. When upgrades are required, no timeline or guidance is offered. We request there be language to require the Public Utility to provide a timeline when upgrades are necessary. If timelines cannot be mutually agreed to, the Applicant then has the option to arrange for a third party to perform the facilities study as provide in section 860-082-055 (6)(b) of the proposed rules.

Small generators can't be held up if some other utility issue has diverted their internal staff. Certainly not when acceptable alternatives exist. Utilities often use consultants to speed or outsource work on interconnection. Small generators should also have this option to hurdle time constraints.

Again, we thank the OPUC staff for the all the work involved in these small generator interconnection rules. The issues can be difficult, complex and polarized. This proceeding is a very important step to helping small generators connect and provide clean power for Oregon.

Sincerely,

Alan Cowan
Renewable Energy Program Manager

Portland General Electric Company
Legal Department
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(503) 464-7611 • Facsimile (503) 464-2200

Richard George
Assistant General Counsel

November 27, 2007

Via Electronic Filing and U.S. Mail

Oregon Public Utility Commission
Attention: Filing Center
550 Capitol Street NE, #215
PO Box 2148
Salem OR 97308-2148

Re: AR 521

Attention Filing Center:

Enclosed for filing in the captioned dockets are an original and one copy of:

- **COMMENTS OF PORTLAND GENERAL ELECTRIC COMPANY.**

This document is being filed by electronic mail with the Filing Center.

An extra copy of this cover letter is enclosed. Please date stamp the extra copy and return it to me in the envelope provided.

Thank you in advance for your assistance.

Sincerely,

J. Richard G

J. RICHARD GEORGE

JRG:smc
Enclosure

cc: Service List-AR 521

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused **COMMENTS OF PORTLAND GENERAL ELECTRIC COMPANY** to be served by electronic mail to those parties whose email addresses appear on the attached service list, and by First Class US Mail, postage prepaid and properly addressed, to those parties on the attached service list who have not waived paper service from OPUC Docket No AR 521.

Dated at Portland, Oregon, this 27th day of November, 2007.

J. Richard George

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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

AR 521

In the Matter of a Rulemaking to Adopt Rules Related to Small Generation Interconnection	Comments of Portland General Electric Company

PGE appreciates the opportunity to provide formal comments on the proposed Oregon Small Generator Interconnection Rules ("Proposed Rules"). As we stated during the hearing on November 13th, we appreciate the collaborative efforts of all the parties involved including the Oregon Public Utility Commission Staff's ("Staff") significant work in organizing stakeholder participation and producing the draft rules.

Largely, the Proposed Rules incorporate changes proposed by PGE that address most of the informal comments and issues PGE has had in the course of their development. PGE has the following additional comments on the rules:

1) Dispute Resolution. PGE supports the proposal offered by the Oregon Department of Energy as Appendix I to its November 27, 2007 comments, which provides for an expedited dispute resolution process before the Commission. PGE does not support binding arbitration or other forms of dispute resolution that would prevent the Commission from being the decision maker concerning disputes. PGE anticipates that disputes, if any arise, may concern the nature and scope of upgrades to be constructed on the utility's system to accommodate the interconnection. In the event PGE is going to be required to compromise or deviate from what it believes is necessary for safety and reliability, it should only do so upon Commission order.

2) Insurance. PGE agrees with and supports comments offered by Pacificorp and others that small generators should be required to obtain reasonable amounts of insurance to cover risks to the system and individuals associated with electrical disturbances created by their generation equipment. PGE believes that the level of insurance necessary should be analyzed in this rulemaking solely from the perspective of the risks associated with interconnection of an operating generator, and not with respect to contractual risks associated with the delivery or sale of electricity. Some parties in comments have referenced that the recent Order No. 07-360 (in docket UM 1129) examined both transactional and electrical risks with respect to small QF facilities and set a precedent that facilities under 200Kw in size should not be required to carry insurance. While the order did reference interconnection risks, PGE notes that the UM 1129 docket specifically addressed developing terms and conditions regarding QF power purchases, not interconnections. *See, e.g.*, Jan. 20, 2004 Staff Report, adopted by the Commission and initiating the docket. The parties did not sufficiently develop the record concerning interconnection safety or risks, and therefore the UM 1129 policies towards insurance required for standard contracts for QFs should not be precedential here.

Likewise, in the AR 521 docket, no party provided dispositive evidence that it is cost prohibitive for a less than 200Kw facility to obtain general liability insurance covering the facility. Some parties did suggest that specialized policies specifically designed for generating facilities might be hard to acquire for small facilities; however, we are not suggesting such specialized policies be required, only that claims regarding facilities be covered, whatever the form of insurance.

Moreover, PGE believes that it is not in the best interests of small generators to be underinsured. In the event of an electrical disturbance, a small generator could be significantly damaged, taking the facility out of service. Without insurance to help small generator's recover or repair the facility, they may be at significant financial risk. Facilities that receive financing for their construction must be able to produce electricity and use proceeds from sales of that electricity to cover debt obligations.

Additionally, if a third party is seriously injured or possibly killed due to a generation facility, the ensuing litigation or claims that may be made against the facility owner place the owner at risk of financial catastrophe. PGE believes that a prudent generator should carry reasonable amounts of insurance covering claims related to the interconnection of its facility.

3) Third-Party Contracting for Construction or Interconnection Studies. While in principle, PGE supports the ideas raised by the Energy Trust of Oregon, Inc. ("ETO") in its November 8, 2007 comments concerning using third-party contractors for interconnection construction, we believe the Proposed Rules would need to include significant additional protections. Specifically, ETO suggested that if the utility and generator cannot agree on timelines to construct necessary facilities or conduct studies for larger Tier 4 facilities, the generator should be able to substitute third parties to carry out the work.

For PGE to allow third-party contractors to work on its system, there would need to be a review process by the utility to ensure that the contractor is qualified to perform such work. Due to critical system stability and safety risks, any contractor working on our system would need to be screened to ensure they had the experience and knowledge to properly and safely do the work. Also, there would need to be a process for the utility to review any design work, and an inspection prior to energization of any facilities constructed. Similar safeguards would need to apply to any studies performed by third-parties regarding upgrades needed on the utility's system. PGE believes strongly that it would need to be compensated for any costs associated with this oversight.

Dated this 27th day of November, 2007

Respectfully Submitted,

__/S/ J. Richard George__________
Assistant General Counsel
Portland General Electric Company

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1610

In the Matter of PUBLIC UTILITY COMMISSION OF OREGON Staff Investigation Into Qualifying Facility Contracting and Pricing.	STAFF'S PROPOSED ISSUES LIST

Background and Procedural History

On July 10th, 2012, the Public Utility Commission held a prehearing conference in Docket UM 1610, and issued a Prehearing Conference Memorandum, setting forth the schedule for identification of the issues. The Hearings Division issued a revised schedule on August 24, 2012. Staff files this issues list in accordance with that revised schedule.

On August 10, 2012, parties to docket UM 1610 held an issues identification workshop. On August 27, 2012, parties including Staff, Idaho Power, PacifiCorp, PGE, ICNU, CREA, Renewable Energy Coalition and ODOE filed initial issues lists. RNP and OSEA filed letters in support of other parties' issues. Staff compiled the parties' issues into one master list and circulated that compilation to the parties on September 12, 2012.

On September 19, 2012 the parties held a second issues workshop. Some of the issues were consolidated or clarified, and a few were eliminated. On September 27th, 2012, Staff distributed to all parties a consolidated issues list based on the discussion at the September 19th workshop. Staff attempted to further consolidate the issues agreed to at the workshop to facilitate the Commission's review of the issues. By further consolidating the issues proposed by parties, Staff did not intend to eliminate any issue that was important to any party. Instead, Staff attempted to draft an issues list sufficiently broad to subsume the issues in the draft issues lists that were circulated by parties and discussed at the workshop on September 19, 2012.

Staff now files its list of consolidated issues in accordance with the schedule stated in the August 24th 2012 ruling. The ruling also directed parties to file, also on October 3rd, proposed issues that were not agreed to by all parties. Parties shall respond by October 10th regarding "disputed" issues. It is Staff's understanding that no party "objects" to the inclusion of any particular issue. Accordingly, Staff anticipates that to the extent a party makes a filing on October

3 or October 10, it would be to clarify that a particular issue that is not expressly set forth below is presented in this proceeding.

I. Standard Avoided Cost Price Calculation

A. What is the most appropriate methodology for calculating avoided cost prices?
    a. Should the Commission retain the current method based on the cost of the next avoidable resource identified in the company's current IRP, allow an "IRP" method based on computerized grid modeling, or allow some other method?
    b. Should the methodology be the same for all three electric utilities operating in Oregon?
B. Should QFs have the option to elect standard or renewable avoided cost prices that are levelized or partially levelized?
C. Should QFs seeking renewal of a standard contract during a utility's sufficiency period be given an option to receive an avoided cost price for energy delivered during the sufficiency period that is different than the market price?
D. Should the Commission eliminate unused pricing options?

These address concerns raised in existing dockets over the last two years, several of which are still open. Issue I.A is the question raised by Idaho Power in UM 1590, and was the issue that led the Commission to open UM 1610. Issues I.B and I.C both are related to concerns (raised primarily by REC) arising because some existing QFs are nearing the end of their current Power Purchase Agreement (PPA). These QFs seek to renew their PPA but may not remain viable if, under the renewed PPA, they receive the market price during the utility's current sufficiency period. (Docket No. UM 1457.) Staff recommends addressing issue I.D because to our knowledge some of the current avoided cost price options such as the "gas market" and "deadband" options have not been used and unnecessarily complicate the schedule.[1] This issue is not included in any other docket.

II. Renewable Avoided Cost Price Calculation

A. Should there be different avoided cost prices for different renewable generation sources? (E.g. different avoided cost prices for intermittent vs. base load renewables; different avoided cost prices for different technologies, such as solar, wind, geothermal, hydro, and biomass.)
B. How should environmental attributes be defined for purposes of PURPA transactions?[2]

[1] Parties at the September 19th workshop identified this issue as one that can likely be settled.
[2] Parties at the September 19th workshop identified this issue as one that can likely be settled.

C. Should the Commission revise OAR 860-022-0075, which specifies that the non-energy attributes of energy generated by the QF remain with the QF unless different treatment is specified by contract?

Issue II.A warrants Commission consideration because two Oregon utilities have testified in prior dockets that different renewable QFs impose different costs on the utility and therefore have different true avoided costs. Idaho Power illustrated this position in testimony supporting its petition for investigation of avoided cost methodology. (Docket No. UM 1593.) PacifiCorp proposed different avoided cost prices for intermittent and renewable QFs in its compliance filing with Order 11-505 (Docket No. UM 1396).

Issue II.B anticipates the implementation of carbon offset credits in addition to renewable energy credits. The Commission should consider this issue in UM 1610 because carbon offset credits would be another environmental attribute that has value to its owner. This issue is not addressed in any other docket.

Issue II.C was proposed by Idaho Power. Idaho Power states that the current rule will potentially expose its customers to significantly higher energy costs in the future. It is not currently addressed in any other docket. PacifiCorp's initial issues list also included the more general question of ownership of environmental attributes.

III. <u>Schedule for Avoided Cost Price Updates</u>

A. Should the Commission revise the current schedule of updates at least every two years and within 30 days of each IRP acknowledgement?
B. Should the Commission specify criteria to determine whether and when mid-cycle updates are appropriate?
C. Should the Commission specify what factors can be updated in mid-cycle? (E.g. factors including but not limited to gas price or status of production tax credit.)
D. To what extent (if any) can data from IRPs that are in late stages of review and whose acknowledgement is pending be factored into the calculation of avoided cost prices?
E. Are there circumstances under which the Renewable Portfolio Implementation Plan should be used in lieu of the acknowledged IRP for purposes of determining renewable resource sufficiency?

The Commission should address Issues III.A, III.B and III.C in this docket because the timing of avoided cost price updates was the subject of debate in PacifiCorp Biennial Avoided Cost Update in March 2012, and Idaho Power's Request for Investigation. (Docket No. UM 1593). Timing of avoided cost updates is also raised in the REC petition initiating Docket No. UM 1457.

Issue III.D was the major area of disagreement during the Commission's review of PacifiCorp's March 2012 two-year update. (Advice 12-005). It is one of the issues in UM 1457. Issue III.E is not addressed in any other docket and is a new issue raised by ODOE. It warrants consideration because there may be circumstances where the RPIP is more current than the IRP as an indicator of the utility's next avoidable renewable resource.

IV. Price Adjustments for Specific QF Characteristics

A. Should the costs associated with integration of intermittent resources (both avoided and incurred) be included in the calculation of avoided cost prices or otherwise be accounted for in the standard contract? If so, what is the appropriate methodology?
B. Should the costs or benefits associated with third party transmission be included in the calculation of avoided cost prices or otherwise accounted for in the standard contract?
C. How should the seven factors of 18 CFR 292.304(e)(2) be taken into account?[3]

Issues IV.A, B and C apply to both the standard avoided cost price stream and the renewable avoided cost price stream. Issue IV.A is significant because PacifiCorp and PGE both propose to include integration in the avoided cost price calculation in their UM 1396 compliance filings, and Idaho Power cited the impact of wind integration as the major driver in its request for investigation. (Docket No. UM 1593). Issue IV.B is the principal issue in Docket No. UM 1546.

The Commission considered issue IV.C in Docket No. UM 1129, but we suggest revisiting it because the FERC lists seven factors that avoided cost calculations should take into account, but there is still no agreement among the parties on how to do so. This issue is not currently addressed in any other docket.

V. Eligibility Issues[4]

A. Should the Commission change the 10 MW cap for the standard contract?
B. What should be the criteria to determine whether a QF is a "single QF" for purposes of eligibility for the standard contract?

[3] The seven factors are (i) ability of the utility to dispatch the QF; (ii) reliability of the QF; (iii) terms of the contract or legally enforceable obligation, termination notice requirement and sanctions for non-compliance; (iv) extent to which scheduled outages of the QF can be usefully coordinated with those of the utility's facilities; (v) usefulness of energy and capacity from the QF during system emergencies including its ability to separate its load from its generation; (vi) individual and aggregate value of energy and capacity from QFs on the utility system and (vii) smaller capacity increments and shorter lead times available with additions of capacity from QFs.
[4] Regarding the issue of ETO funding of QFs, ALJ Grant's letter to Margie Harris of September 13, 2012 includes the Commission's direction to staff to continue working with the ETO on incentive policies.

C. Should the resource technology affect the size of the cap for the standard contract cap or the criteria for determining whether a QF is a "single QF"?
D. Can a QF receive Oregon's Renewable avoided cost price if the QF owner will sell the RECs in another state?

The Commission investigated issue V.A extensively in Docket No. UM 1129. However, almost every party to UM 1610 recommended that we address it again, asserting that new facts and circumstances have arisen since the issuance of Order 05-584. Issue V.A is not currently addressed in any other docket, although Idaho Power did petition for a lower eligibility cap in January 2012 (Docket No. UM 1575). Issue V.B is the subject of Docket No. UM 1616. It is significant because utilities have repeatedly raised the concern over disaggregation, notably Idaho Power in the petitions that initiated Docket Nos. UM 1575 and UM 1593. Idaho Power stated in its recommended issues list that a lower cap could resolve the underlying concerns regarding the definition of a "single facility." Issue V. C was proposed by PacifiCorp and is likely to be raised in any discussion of the eligibility cap. It is not addressed in any current docket. Issue V.D was raised during the review of PGE and PacifiCorp compliance filings with Order 11-505. (Docket No. UM 1396).

VI. Contracting Issues

A. Should the standard contracting process, steps and timelines be revised? (Possible revisions include but are not limited to: when an existing QF can enter into a new PPA and the inclusion of conditions precedent to the PPA including conditions requiring a specific interconnection agreement status.)
B. When is there a legally enforceable obligation?
C. What is the maximum time allowed between contract execution and power delivery?
D. Should QFs <10 MW have access to the same dispute resolution process as those > 10 MW?
E. How should contracts address mechanical availability?
F. Should off-system QFs be entitled to deliver under any form of firm point to point transmission that the third party transmission provider offers? If not, what type of method of delivery is required or permissible? How does method of delivery affect pricing?
G. What terms should address security and liquidated damages?
H. May utilities curtail QF generation based on reliability and operational considerations, as described at 18 CFR §292.304(f)(1)? If so, when?
I. What is the appropriate contract term? What is the appropriate duration for the fixed price portion of the contract?

Issues VI.A through D are concerns raised by QF stakeholders in existing dockets, for example Docket No. UM 1457. ODOE, REC and CREA have identified the PPA negotiation process as a concern equal to the avoided cost calculation method. Issues VI.E and F are the issues raised in Docket No. UM 1566. Issues VI. G, H and I are issues raised by the Oregon utilities. The question of appropriate contract term is significant particularly to ODOE's Small Scale Energy Loan program, because the term of the PPA is a factor in the term of the loan.

VII. Interconnection Process

A. Should there be changes to the interconnection rules, policies or practices to facilitate the timely execution of PPAs under PURPA and a more expeditious process for constructing a QF and bringing it on line?
B. Should the interconnection process allow, at QFs request or upon certain conditions, third-party contractors to perform certain functions in the interconnection review process that are currently performed by the utility?

Issues VII.A and B are significant because the PPA process and interconnection process are interrelated through conditions in the PPA process that refer to milestones in the interconnection process. A detailed discussion of the PPA process is likely to include a discussion of its interrelation with the interconnection agreement process. REC, CREA and ODOE all raise this interrelation as a concern. These issues are described in detail in the initiating petition for Docket No. UM 1457.

Dated at Salem, Oregon, this 3rd day of October, 2012.

Adam Bless

Adam Bless
Senior Utility Analyst
Electric Rates and Planning

CERTIFICATE OF SERVICE

UM 1610

I certify that I have, this day, served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-001-0180, to the following parties or attorneys of parties.

Dated this 3rd day of October, 2012 at Salem, Oregon

Kay Barnes

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October 10, 2012

Via Electronic and FedEx

Public Utility Commission
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Re: In the Matter of Public Utility Commission of Oregon Investigation Into Qualifying Facility Contracting and Pricing
Docket No. UM 1610

Dear Filing Center:

Enclosed please find the original and five (5) copies of the Comments on behalf of the Renewable Energy Coalition in the above-referenced docket.

Thank you for your assistance.

Sincerely,

/s/ Sarah A. Kohler
Sarah A. Kohler

Enclosures
cc: Service List

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the foregoing Comments on behalf of the Renewable Energy Coalition upon the parties, on the service list, by causing the same to be deposited in the U.S. Mail, postage-prepaid, and via electronic mail.

Dated at Portland, Oregon, this 10th day of October, 2012.

Sincerely,

/s/ Sarah A. Kohler
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BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1610

In the Matter of PUBLIC UTILITY COMMISSION OF OREGON Investigation Into Qualifying Facility Contracting and Pricing	)))))))	RENEWABLE ENERGY COALITION RESPONSE TO DISPUTED ISSUES

I. INTRODUCTION

The Renewable Energy Coalition ("REC") submits this response to PacifiCorp's objection to the inclusion of issues related to the interconnection process in the Oregon Public Utility Commission's (the "Commission" or "OPUC") investigation into qualifying facility ("QF") contracting and pricing under the Public Utility Regulatory Policies Act ("PURPA"). The interconnection issues raised by REC, the Community Renewable Energy Association ("CREA") and the Oregon Department of Energy ("ODOE") are directly related to the QF contracting and pricing issues and have caused some of the disputes that have resulted in the Commission opening this investigation. Contrary to PacifiCorp's comments, consideration of discrete and limited issues regarding the interconnection process will not significantly expand the scope of the process or cause unnecessary delay, but will instead allow the Commission to establish policies and resolve some core issues in a holistic manner. Therefore, the two issues included on Staff's proposed list ("List") related to changes to the interconnection rules, practices and policies regarding more timely and expeditious power purchase agreements

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("PPA"), and whether third-party contractors should be allowed to perform additional work should be considered in this proceeding. Both the CREA and the Renewable Northwest Project support this response and the inclusion of interconnection issues in this proceeding.

II. BACKGROUND

On June 29, 2012, the Commission opened this investigation to address, in a generic fashion, a number of QF-related controversies regarding PURPA implementation and QF contracting. Over the past few years, the Commission and the courts have been presented with a number of complaints by QFs over contracting, pricing, and interconnection issues. There also have been disputes about the timing and frequency of avoided cost updates, proposals by utilities to suspend or modify their obligations to purchase QF power, and the need to investigate the utilities' new renewable avoided cost rates. In addition, this proceeding is also related to REC's November 2009 request for an investigation to address a number of utility practices that discourage QF development.

Staff conducted a number of workshops to consider the scope of issues in this proceeding and to develop a consensus list of issues. Staff and many of the parties worked hard to consolidate, reduce, and narrow lists as much as possible using an approach that no issues of key importance to any of the other parties would be excluded. There are many issues on Staff's List that, during the workshops, one or more parties opposed including. Parties, however, recognized that the general approach was to include issues that at least one party believed should be considered.

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REC, CREA, and ODOE all raised a number of issues related to the interconnection process but eventually dropped some of their issues, and the interconnection process issues were narrowed and consolidated into the following:

- Should there be changes to the interconnection rules, policies, or practices to facilitate the timely execution of PPAs under PURPA and a more expeditious process for constructing a QF and bringing it on line?

- Should the interconnection process allow, at the QF's request or upon certain conditions, third-party contractors to perform certain functions in the interconnection review process that are currently performed by the utility?

These issues were included on Staff's List. In addition, REC has requested that Administrative Law Judge ("ALJ") Grant add an issue regarding the timing of the interconnection process and the PPAs. Specifically, REC believes that the interconnection milestones should be removed from the PPA. PacifiCorp filed its proposed issues list and was the only party to formally object to the inclusion of this or any other issue in the proceeding.

III. RESPONSE

The contracting and pricing negotiation process for QFs is intricately tied to the interconnection process, and it is impossible to resolve many contractual disputes without considering the interconnection process. This proceeding should not be the forum for a broad revision or modification of the Commission's existing interconnection rules, but should consider making a limited number of important changes that will better ensure that the interconnection and PPA contracting processes work together and do not provide unnecessary hurdles or impediments. Further, these changes will help to prevent certain future disputes between QFs and utilities.

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The Commission adopted rules for large and small generator interconnections. E.g., Re Rulemaking to Adopt Rules Related to Small Generator Interconnection, Docket No. AR 521, Order No. 09-196 (June 8, 2009); OAR §§ 860-029-0060, 860-082-0005. REC largely supports these rules and the intent or spirit of Order No. 09-196 as providing much needed clarity and consistency in the interconnection process. After several years of implementation of the rules, there are some limited areas that require revision due to ambiguity. The Commission's interconnection rules, policies, and practices should be revised to streamline the process, provide more clarity, and facilitate more cost effective and timely interconnections.

In submitting its proposed issues list, Staff recognized the importance of addressing interconnection and contracting issues holistically. Staff explained that the two interconnection process issues should be included in this proceeding and "are significant because the PPA process and interconnection process are interrelated through conditions in the PPA process that refer to milestones in the interconnection process." Staff Issues List at 6. As Staff recognized, QFs often face milestones in their PPA or interconnection process that provides them with little opportunity to review, question, or mitigate the interconnection requirements and estimates. The process has been presented as a take-it-or-leave-it proposition. This in turn causes problems for the QF meeting its PPA obligations, as defaults are commonly tied to the completion of major interconnection steps or a date certain to commence deliveries. Similarly, both the amount of time to complete the interconnection and the estimated costs often change dramatically.

PacifiCorp opposes addressing interconnection issues in this proceeding on the grounds that this will require the Company to bring different utility representatives into this case,

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and interconnection issues are different. PacifiCorp Issues List at 2. From the perspective of QFs, the interconnection and PPA contract process are inextricably linked, and many of the problems arise because they are often seen as two separate processes that do not consider how they impact each other. A QF cannot enter into a PPA without a valid interconnection, but the time lines, delays, and cost overruns associated with the interconnection process can result in a QF failing to meet its PPA obligations due to no fault of its own. While REC recognizes that there are some aspects of utility's operations that are not allowed to be communicated during the contract negotiation process, this functional separation supports the inclusion of both interconnection and PPA issues in this generic proceeding. Now, and not during the contract negotiation process, is the best time and opportunity to ensure that the interconnection process does not impose unnecessary burdens on the PPA contract process, and vice versa.

Another interconnection issue inter-related to the PPA contract process is the use of third-party contractors. There is a wide variety of interconnection-related issues in Oregon that allow the utilities to use their leverage in the interconnection process to force concessions in the PPA contract negotiation process or otherwise harm the QFs. These include inaccurate cost and time estimates, additional requirements, amounts for progress payments, timing, and final accounting. In lieu of raising these issues, REC and other parties agreed to focus on a potential solution: allowing QFs the ability to use and contract with utility-approved third parties for portions of the interconnection work, from studies to construction. Typically, such approved contractors are used to perform interconnection work but under the direction of the utility. Having the QF contract directly with the approved third-party contractor can provide the QF with the essential control of the costs, the time for completion, and meeting its power purchase

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obligations. Direct contracting with third parties can also limit the utilities' exposure to excessive cost claims and failure to meet critical deadlines.

PacifiCorp is wrong to assert that consideration of these issues will significantly expand the scope of the proceeding or cause unnecessary delay. The utilities propose to change the Commission's decisions from UM 1129 by reducing the 10 megawatt size threshold, changing the contract length, and suspending the utilities' PURPA obligations. These changes are far more likely to expand the scope of the proceeding and delay resolution of a number of time sensitive issues in this proceeding. New QFs and many long-standing older QFs that need to update their interconnections cannot enter into PPAs without a fair and timely interconnection process, and the Commission should consider specific and limited revisions to its interconnection rules, practices, and policies to ensure that the interconnection and PPA processes work as seamlessly as possible.

IV. CONCLUSION

The Commission has already established PURPA related policies and rules that attempt to balance carefully the interest of QFs and ratepayers, and REC is not proposing that the Commission make radical or wholesale changes in either the PPA or interconnection process. The Commission, however, should make changes to the interconnection process that would allow for negotiating both purchase power and interconnection agreements in a way that does not increase costs or risk to ratepayers and minimizes the number of disputes. REC appreciates the Commission considering these important issues and urges the ALJ not to exclude any important issues that can be resolved in a narrow and straight-forward manner.

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Dated this 10th day of October, 2012.

Respectfully submitted,

DAVISON VAN CLEVE, P.C.

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ISSUED: October 25, 2012

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1610

In the Matter of PUBLIC UTILITY COMMISSION OF OREGON Investigation into Qualifying Facility Contracting and Pricing.	RULING

DISPOSITION: ISSUES LIST FINALIZED

The Commission opened this investigation into QF issues in response to numerous disputes about contracting, pricing, and interconnection issues, as well as various proposals by utilities to modify how avoided costs are calculated. The Commission's purpose of this docket is to address, in a generic fashion, issues related to PURPA implementation and QF contracting.

Issues List

Following two workshops, Staff and parties submitted a consolidated list of proposed issues organized in seven sections: (1) Avoided Cost Price Calculation; (2) Renewable Avoided Cost Price Calculation; (3) Schedule for Avoided Cost Price Updates; (4) Price Adjustments for Specific QF Characteristics; (5) Eligibility Issues; (6) Contracting Issues; and (7) Interconnection Issues. In addition, Renewable Northwest Project (RNP); the Renewable Energy Coalition (REC); the Community Renewable Energy Association (CREA); and PacifiCorp, dba as Pacific Power; separately filed comments proposing additional sub-issues.

Overall, there is general agreement between the parties as to the relevant issues that should be addressed by the Commission. The primary disagreement was whether to include issues identified in section (7) relating to interconnection. Pacific Power recommends that these issues be addressed in a separate docket because the interconnection process is distinct from the contracting process. According to Pacific Power, including those issues here has the potential to significantly expand the scope of this docket, cause delay, and would require participation from a separate set of company representatives—those from its transmission services department. Pacific Power states that having both its QF contracting and pricing staff and its transmission services staff participate in this docket would be difficult due to the functional separation requirements imposed by FERC that limit interaction between these two groups.

Staff, REC, and the Oregon Department of Energy oppose Pacific Power's recommendation to exclude interconnection issues. These parties believe that the contracting and pricing process of QFs is intricately related to the interconnection process, and that it would be impossible to resolve many contractual disputes without considering the interconnection process. In addition, Staff believes that including interconnection issues in this docket presents a problem with FERC's separation rules. Staff explains that those rules prevent the transmission department from sharing information with the company's merchant activities that might create an unfair advantage. Staff notes that any interaction between the two departments here would take place as part of an open and public process.

I conclude that interconnection issues should be included in this docket. To address Pacific Power's concern about unreasonably broadening the scope of this proceeding, I modify Issue 7A to clarify its focus and to incorporate the related sub-issue proposed by REC regarding the link between power purchase agreements and interconnection milestones.

I also adopt the additional sub-issue proposed both by CREA and Pacific Power to address the process and requirements or modification of standard contracts. I do not include the sub-issue proposed by RNP to address the establishment of a separate solar avoided cost rate. RNP is correct that a separate legal basis exists for a solar avoided cost rate under the mandatory purchase requirement contained in ORS 757.370. There is no need, however, to set this issue out separately. RNP may raise this issue under Issue 2A that generally addresses establishing avoided costs for different renewable generation sources. Finally, I adopt Pacific Power's proposed amendments to Issues 1A and 1B to remove reference to "standard" avoided costs. I agree with Pacific Power that the use of the term "standard" might cause confusion with the differing use of the term to refer to non-negotiated standard contract for small QFs.

Accordingly, the list of issues, set forth in Appendix A, is adopted for this proceeding.

Procedural Schedule

The parties are directed to confer and develop a proposed schedule for this proceeding. Given the number of issues, the parties should discuss how the issues should be divided into phases, with the most time sensitive issues to be addressed first. Also, the parties should discuss and recommend what the Commission should do with the various QF proceedings whose issues have now been moved into this proceeding.

The parties should file a jointly agreed-upon proposed schedule with phase recommendations by November 9, 2012. If the parties are unable to reach agreement, they should request the Commission schedule a prehearing conference.

Dated this 25th day of October, 2012, at Salem, Oregon.

Michael Grant
Chief Administrative Law Judge

Appendix A
Issues List – UM 1610

1. Avoided Cost Price Calculation

   A. What is the most appropriate methodology for calculating avoided cost prices?
      i. Should the Commission retain the current method based on the cost of the next avoidable resource identified in the company's current IRP, allow an "IRP" method-based on computerized grid modeling, or allow some other method?
      ii. Should the methodology be the same for all three electric utilities operating in Oregon?
   B. Should QFs have the option to elect avoided cost prices that are levelized or partially levelized?
   C. Should QFs seeking renewal of a standard contract during a utility's sufficiency period be given an option to receive an avoided cost price for energy delivered during the sufficiency period that is different than the market price?
   D. Should the Commission eliminate unused pricing options?

2. Renewable Avoided Cost Price Calculation

   A. Should there be different avoided cost prices for different renewable generation sources? (*for example* different avoided cost prices for intermittent vs. base load renewables; different avoided cost prices for different technologies, such as solar, wind, geothermal, hydro, and biomass.)
   B. How should environmental attributes be defined for purposes of PURPA transactions?
   C. Should the Commission amend OAR 860-022-0075, which specifies that the non-energy attributes of energy generated by the QF remain with the QF unless different treatment is specified by contract?

3. Schedule for Avoided Cost Price Updates

   A. Should the Commission revise the current schedule of updates at least every two years and within 30 days of each IRP acknowledgement?
   B. Should the Commission specify criteria to determine whether and when mid-cycle updates are appropriate?
   C. Should the Commission specify what factors can be updated in mid-cycle? (*such as* factors including but not limited to gas price or status of production tax credit.)
   D. To what extent (if any) can data from IRPs that are in late stages of review and whose acknowledgement is pending be factored into the calculation of avoided cost prices?

E. Are there circumstances under which the Renewable Portfolio Implementation Plan should be used in lieu of the acknowledged IRP for purposes of determining renewable resource sufficiency?

4. Price Adjustments for Specific QF Characteristics

A. Should the costs associated with integration of intermittent resources (both avoided and incurred) be included in the calculation of avoided cost prices or otherwise be accounted for in the standard contract? If so, what is the appropriate methodology?
B. Should the costs or benefits associated with third party transmission be included in the calculation of avoided cost prices or otherwise accounted for in the standard contract?
C. How should the seven factors of 18 CFR 292.304(e)(2) be taken into account?

5. Eligibility Issues

A. Should the Commission change the 10 MW cap for the standard contract?
B. What should be the criteria to determine whether a QF is a "single QF" for purposes of eligibility for the standard contract?
C. Should the resource technology affect the size of the cap for the standard contract cap or the criteria for determining whether a QF is a "single QF"?
D. Can a QF receive Oregon's Renewable avoided cost price if the QF owner will sell the RECs in another state?

6. Contracting Issues

A. Should the standard contracting process, steps and timelines be revised? (Possible revisions include but are not limited to: when an existing QF can enter into a new PPA and the inclusion of conditions precedent to the PPA including conditions requiring a specific interconnection agreement status.)
B. When is there a legally enforceable obligation?
C. What is the maximum time allowed between contract execution and power delivery?
D. Should QFs smaller than 10 MW have access to the same dispute resolution process as those greater than 10 MW?
E. How should contracts address mechanical availability?
F. Should off-system QFs be entitled to deliver under any form of firm point to point transmission that the third party transmission provider offers? If not, what type of method of delivery is required or permissible? How does method of delivery affect pricing?
G. What terms should address security and liquidated damages?

H. May utilities curtail QF generation based on reliability and operational considerations, as described at 18 CFR §292.304(f)(1)? If so, when?

I. What is the appropriate contract term? What is the appropriate duration for the fixed price portion of the contract?

J. What is the appropriate process for updating standard form contracts, and should the utilities recently filed standard contracts be amended by edits from the stakeholders or the Commission?

7. Interconnection Process

A. Should PPAs include conditions that reference the timing of the interconnection agreement and interconnection milestones? If so, what types of conditions should be included?

B. Should QFs have the ability to elect a larger role for third party contractors in the interconnection process? If so, how could that be accomplished?

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1610

In the Matter of PUBLIC UTILITY COMMISSION OF OREGON Staff Investigation Into Qualifying Facility Contracting and Pricing	STAFF'S RESPONSE TO DISPUTED ISSUES

On October 3 2012, Staff filed its consolidated list of issues for UM 1610. That list was the product of a series of issue statements and workshops among all the parties, held over the months of August and September 2012. As described in the ALJ's August 24 procedural ruling, parties also filed their own "disputed" issues on October 3, 2012.

Staff wants to clarify that, although we used the term "consensus list" in our October 3, 2012 filing, not every issue on that list had 100 percent agreement. As stated in its October 3 filing, Staff's intent in consolidating issues was not to eliminate an issue that was important to any party. For that reason, there are some issues on Staff's proposed list that did not have 100 percent agreement but were important enough to one or more parties to warrant consideration. The fact that no party objected to a proposed issue was sufficient for its inclusion, but not absolutely necessary.

Staff now responds to the lists of disputed issues filed on October 3 by Renewables Northwest Project (RNP), Renewable Energy Coalition (REC), Community Renewable Energy Association (CREA) and PacifiCorp.

<u>RNP</u> recommended that we add: "Should there be a special avoided cost rate based on the mandatory purchase obligation in ORS 757.370 (the Minimum Solar Energy Capacity Standard)?"

<u>REC</u> recommended that we add: "Should we recognize that there may be a mismatch between the timing of the execution of the interconnection agreement and interconnection milestones in the PPA which warrants the elimination of the interconnection milestones in the PPA?"

<u>CREA</u> recommended that we add: "What is the appropriate process for updating standard form contracts, and should the utilities' recently filed standard form contracts be amended by edits from stakeholders or the Commission?"

PacifiCorp recommended adding two additional issues:

i. Should the current standard form contract terms and conditions be revised and what is the process and requirements for future modifications of the standard form contracts terms and conditions; and

ii. Should QFs have the option to elect standard or renewable avoided cost prices that are levelized or partially levelized?

Staff has no objection to the issues proposed for addition. All of them were on the draft issues lists provided by the parties during the workshop process. Staff believes that these issues are implicitly contained in more broadly stated issues on our list of October 3, but supports stating them explicitly if that will clarify the scope of the investigation. The issue requested by CREA is essentially the same as the first issue recommended for addition by PacifiCorp.

PacifiCorp also recommended deleting two issues:

i. Should there be changes to the interconnection rules, policies or practices to facilitate the timely execution of PPAs under PURPA and a more expeditious process for constructing a QF and bringing it on line?

ii. Should the interconnection process allow, at QFs request or upon certain conditions, third party contractors to perform certain functions in the interconnection review process that are currently performed by the utility?

PacifiCorp suggested addressing interconnection issues in a separate docket, stating that including them in UM 1610 would expand the scope of the docket, cause unnecessary delay, and involve a different set of Company representatives, namely those from the transmission services department. PacifiCorp stated that FERC regulations require functional separation between the two departments and allow limited interaction. Staff does not believe there is a conflict with FERC's separation rules. Those rules prevent the transmission department from sharing information with the Company's "merchant" side that might create an unfair advantage. However, any interaction between the two PacifiCorp departments would take place in open public meetings, and all information in this docket is part of an open and transparent process.

Regarding concerns over broadening the docket scope, Staff notes that the interaction between the PPA and interconnection process is already under investigation in UM 1457. Excluding the issue from this docket will not resolve it. The PPA and interconnection processes are already somewhat linked because the PPA process set forth in Schedule 37 references the status of the interconnection as one of the prerequisites. Staff's understanding is that the Commission's intent in opening this generic docket was to take a big picture look at a number of outstanding open dockets, UM 1457 among them. Staff believes that investigating the link between the PPA process and the interconnection process is consistent with the Commissioners' statements at the May 2012 Public Meeting at which it opened this generic docket.

Staff suggests we alleviate concerns about over-broadening this docket with a more focused issue statement. The principal issues raised in the petition for UM 1457 and by REC, CREA, ICNU and ODOE during the workshop process were: (i) the extent to which milestones in the interconnection process can delay the PPA process, and (ii) a larger role for third party contractors in the interconnection process. Staff believes a more focused issue statement can resolve the largest concerns without overly delaying the investigation. A more focused issues statement would be:

(i) Should conditions in the PPA process that reference the status of interconnection agreements be modified so that the steps in the interconnection process do not impede the progress of the PPA?

(ii) Should QFs have the ability to elect a larger role for third party contractors in the interconnection process? If so, how could that be accomplished?

No other party filed a list of disputed issues. Staff appreciates the input and comments from all parties.

Dated at Salem, Oregon, this 10th day of October 2012.

Adam Bless

Adam Bless
Senior Utility Analyst
Electric Rates and Planning

CERTIFICATE OF SERVICE

UM 1610

I certify that I have, this day, served the foregoing document upon all parties of record in this proceeding by delivering a copy in person or by mailing a copy properly addressed with first class postage prepaid, or by electronic mail pursuant to OAR 860-001-0180, to the following parties or attorneys of parties.

Dated this 10th day of October, 2012 at Salem, Oregon

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Introduction

Federal law lays out general requirements for implementation of Public Utility Regulatory Policies Act (PURPA), but provides broad authority to state commissions to establish their own implementation policies. On January 31, 2019 the Oregon Public Utility Commission (Commission) held a Special Public Meeting (SPM) to solicit input from stakeholders on PURPA implementation in Oregon. Stakeholders raised issues on fairness of current processes, as well as current avoided cost rates. At the SPM Staff stated their agreement with the need for a broad PURPA investigation and laid out three principles that successful Oregon PURPA implementation would encompass. These three design principles would:

- Promote development of a diverse array of sustainable energy resources
- Ensure that utilities pay just and reasonable prices, maintaining a customer indifference standard
- Create a regulatory process that provides efficiency, clarity, and engenders confidence from all stakeholders.

There are a host of identified issues with PURPA implementation in Oregon today that make achievement of these principles challenging. There are lengthy and incessant lawsuits before the Commission and Staff has heard from prior investigations that projects cannot interconnect; influx of QF PPAs for projects that may not appear creates difficulties for utilities in planning; a large number PURPA projects sit in contracting limbo while Oregon utilities procure other resources; and avoided costs do not reflect market realities, nor do they align with utility procurement. A review of PURPA implementation at this juncture is a timely way to address multiple issues.

This draft white paper provides a draft scope and recommended direction this investigation into PURPA implementation could take to address several key policy issues, including the ones listed above, so that PURPA more effectively serves the interests of ratepayers. It incorporates feedback from an additional stakeholder workshop, written comments from parties, as well as topics raised in past Commission orders.[1] The main principles remain the same as those stated at the January 31, 2019 SPM, with fair, efficient, transparent and timely as the determinants of success.

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[1] *In the Matter of PacifiCorp dba Pacific Power, Application to Update Schedule 37 Qualifying Facility Information* (UM 1794); Order No. 17-239, p. 3 ("We acknowledge a need to address, among other matters: 1. Challenges that may exist with examining a utility's resource deficiency date for avoided cost purposes*** and 2. Avoided cost implications where a utility is pursuing near-term capacity investments not driven by reliability, RPS, or load-service needs."); *In the Matter of PacifiCorp dba Pacific Power, Updates Standard Avoided Cost Purchases from Eligible Qualifying Facilities* (UM 1729), Order 18-289, p. 6 ("PacifiCorp's motion correctly observes that many elements of our avoided cost methodology are based on the supposition that renewable energy is generally more expensive than nonrenewable alternatives. We find that PacifiCorp has presented significant policy questions regarding our determination in Order No. 11-505 to offer renewable QFs access to their choice of pricing options, which should be addressed in the new comprehensive proceeding."); and *In the Matter of Obsidian Renewables LLC Petition to Amend OAR 860-029-0040, Relating to Power Purchases by Public Utilities From Small Qualifying Facilities* (AR 593); Order No. 18-422, p. 6. ("Finally, we note these provisions have implications regarding impacts of speculation in a falling price market, which brings up broader questions regarding our overall implementation of PURPA, which we expect to address in further proceedings to investigate PURPA.").

UM 2000 Process

In the Notice and Agenda sent out before the January 31, 2019 SPM the Commission asked stakeholders three questions:

1) What are the key characteristics of successful future PURPA implementation in Oregon?
2) What are the top two PURPA implementation issues the Commission should address?
3) Should the Commission make interim changes to PURPA implementation while it undertakes a broader review?

The meeting included presentations and comments from many stakeholders. Comments addressed issues of most concern to stakeholders, including, but not limited to, interconnection issues, cost disparity between actual avoided costs and avoided cost rates, as well as contractual concerns. As a result of the meeting, the Commission directed Staff to examine immediate, interim actions, as well as the potential for a general investigation.

At the February 14, 2019 Public Meeting Staff presented options for interim actions and potential issues to examine in a broader investigation. At Staff's recommendation, the Commission opened this investigation docketed as UM 2000,[2] and also opened an investigation into interim actions, docketed as UM 2001.[3] The two dockets have moved on separate paths, with UM 2001 focused on enhanced avoided cost rate updates and making interconnection data more readily available to developers. The UM 2000 docket has focused on longer-term issues with some overlap with UM 2001 activities.

Following the Commission's order opening the UM 2001 docket, Staff commenced a process to draft this white paper to define a proposed scope for the investigation. Staff obtained stakeholder input on the issues to be addressed in this docket and whether any of the issues could be prioritized. Staff followed a twofold approach to define a draft scope by first examining issues that can be resolved in a short-term fashion and then identifying those issues that may require a longer timeframe for examination and a recommended process for that examination.

Identification of Issues

Staff sent a questionnaire to stakeholders on March 15, 2019 with responses due on March 29, 2019. This questionnaire was presented in two parts. The first part was directed at the utilities, to explore their current processes, and establish a baseline understanding for all stakeholders. There was some concern from non-utility stakeholders that at least some of these questions should have been directed to all stakeholders. As mentioned, Staff was looking to establish a framework for all parties to understand current utility approaches.

The second part of the questions looked to all stakeholders to address a set of myriad issues. These questions were developed, in part, based on information and comments provided in response to the January 31, 2019 SPM regarding PURPA implementation. Staff was looking for a better understanding of:

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[2] *In the Matter of the Public Utility Commission of Oregon Investigation into PURPA Implementation* (UM 2000), Order No. 19-051.
[3] *In the Matter of the Public Utility Commission of Oregon Investigation into Interim PURPA Action* (UM 2001), Order No. 19-052.

- Areas where current processes could be improved;
- Difficulties faced by developers or utilities;
- The treatment and value of resources, both existing and new;
- Interconnection in Oregon;
- Legally enforceable obligations (LEOs); and
- Standard contracts, as both a document and its associated process.

The list of questions, as well as a summary of responses, can be found in Appendix A.

Staff scheduled a workshop for April 5, 2019 to discuss responses received, as well as other issues raised by stakeholders. At the workshop, Staff presented some high-level themes from the March 29, 2019 comments including some areas of potential agreement. There was a collaborative, small-group exercise that broke attendees into four parties that rotated around the room to discuss four main categories of issues: Avoided Cost, Contracts, Interconnection, and Planning. Participants in each party noted their concern and had a chance to explain their concern to their small-group.[4] Several stakeholders felt the categories were not comprehensive. They suggested potential additional categories such as transmission. Also, it was noted that a common theme through all categories was process. That is, the process to get a contract, the process for receiving an interconnection agreement, and dispute resolution, for example.

In response to Stakeholder feedback at the April 5, 2019 workshop regarding the fast progress of UM 2000, Staff revised the informal schedule to allow for more time for comments that would help scope the docket. Parties were asked to provide any additional comments to the March 15, 2019 questions by April 26, 2019. In their responses parties were asked to add any additional concerns they may have following the workshop. A high-level summary of the responses received is included as Appendix C.

Parties were also offered additional time to comment during the scoping phase of the docket, which is proposed to be end in July. The current schedule envisioned for the remainder of this first phase is below.

- Week of May 27, 2019 – Staff draft whitepaper posted
- June 7, 2019 – Stakeholder comments on Whitepaper
- June 11, 2019 – Commissioner workshop
- June 25, 2019 – Stakeholder comments on Commissioner workshop
- July 16, 2019 – Public meeting for presentation of Staff memo and final whitepaper

History of PURPA Implementation in Oregon

The Commission commenced implementation of PURPA in 1980 with two rulemaking proceedings, one to adopt rules related to the determination of avoided cost prices and another for rules related to contracting.[5] After adopting rules in 1981, the Commission determined and modified policies over the

[4] Results of this exercise are included in Appendix B.

[5] *In the Matter of the Investigation into Electric Utility Tariffs for Cogeneration and Small Power Production Facilities* (R-58), Order Nos. 81-319 and 81-755.

- Ensure appropriate requirements (no gold-plating).
- Provide appropriate cost sharing.
- Address network resource interconnection service requirement for QFs and lack of eligibility for refunds for network upgrades.
- Address lack of procedures for generators between 10 and 20 MW.

RNW and OSEIA

- Strengthen requirements related to initial information available to QFs prior to interconnection application.
- Make timelines more predictable.
- Do not require QFs to bear full costs of network upgrades that are used by others.

Planning

The major issue associated with planning raised by parties is the treatment of QFs in the IRP process. There was also a strong desire for the opportunity for meaningful participation in the IRP process by stakeholders. That is, it will be hard for stakeholders to challenge variables and results from an acknowledged IRP. These variables in turn will form the basis of the avoided cost rates.

QF Trade Associations:

- Address capacity value of existing QFs
- Create realistic opportunity to challenge IRP inputs.

Prioritization of Actions

The intent of this white paper is to develop a well-defined scope for the UM 2000 investigation that will ensure PURPA implementation is fair, efficient, transparent and timely for both QFs and utility ratepayers. Staff suggests some items to focus on in the near term on a 'fast-track' agenda, as well as some items that will take more time to investigate. Staff proposes to bifurcate these issues into different processes to ensure timely progress on items that can be resolved in short order to improve PURPA implementation in Oregon while creating a place to address long-term issues. The proposed near-term actions in this draft whitepaper have the potential to resolve many issues related to litigation.

Both near- and longer-term processes can take place in parallel to hopefully mitigate any timing issues.

Near-Term (fast-track) Actions

Avoided cost:

To address the issue of inconsistent and complex tools that are difficult for Staff and other stakeholders to review in a timely manner, Staff will work with stakeholders to develop a standardized template for avoided cost modeling inputs and outputs. This template will be used for the current modeling methodology. A broader investigation into the appropriate modeling methodology will be part of the longer-term activities. Note, this methodology and associated rates could be impacted by the general capacity investigation in Docket No. UM 2011.

Contracts:

Staff proposes to draft a straw proposal of standard contract procedures and terms to initiate a holistic review of contract terms. The terms of a contract are interdependent and previous changes to certain terms of a contract after a complaint proceeding or general investigation can have unintended consequences for the application or implementation of other terms. A holistic examination of PURPA standard contracts, with emphasis on obtaining internal consistency that balances the interests of the utility and QFs would benefit the Oregon wholesale market and ratepayers. The following are some of the broad issues that Staff would want to attempt to address in the near-term:

(1) What would contract timing, term, project size, compensation, security, and renewal encompass?

(2) What is the minimum levels of information to be provided?

(3) Will there be any contractual flexibility due to technology improvements (pre- and post-construction)?

(4) How should damage provisions be incorporated?

(5) What is the appropriate treatment of storage?

Interconnection:

Near-term activities for interconnection are being covered in UM 2001. Proposals for UM 2000 should build on the work that's being done in that docket. The QF Trade association included a list of near-term interconnection issues they believe could help end litigation. Staff believes the majority of the issues identified could be addressed on a fast track. These fast-track issues include more transparent process, access to studies, dispute resolution, and treatment of costs associated with network upgrades, among others. Some of the questions that could be resolved as part of the near-term Staff activities would include:

(1) What is the appropriate level of detail to provide in interconnection studies?

(2) What options does a QF have to perform its own studies, or upgrades?

(3) Should there be modifications to the current process, including more enforceable timelines?

(4) Should independent third parties be retained to review studies?

(5) Are there further data access issues not captured in Docket UM 2001?

(6) In designing the interconnection, are there lower-cost alternatives that are being overlooked?

(7) What is the level of SCADA data needed – and for what size QF?

(8) What rules/guidelines apply to 10-20 MW projects?

Planning:

Staff believes issues related to planning and contract renewals could be addressed on a fast track. There are issues related to planning that have been discussed in multiple dockets, including UM 1610, and PacifiCorp's IRP related to treatment of QFs long-term planning. These revolve around the issues of how to consider QFs and the potential for contract renewals in the IRP. The issue will get at the potential for renewing QFs to receive capacity payments at the beginning of their second contract. Staff believes this is an issue that could be fast-tracked, recognizing that the general capacity investigation could play a role in this value as well.

Additional questions relate to the amount of executed PPAs for QFs that are not yet on-line and how they are treated in the IRP process. As shown above, the amount of QF projects undergoing development is large (especially for PGE) as compared to their resource needs. Assuming all these QFs come online may not be appropriate. How many to include would benefit from stakeholder review. These assumptions may impact the sufficiency/deficiency demarcation, and impact pricing.

Long-Term Actions

Staff believes the issues below will require additional time to develop a record prior to a Commission decision and are not included Staff's proposed scope of near-term activities.

Avoided Costs:

Appropriate avoided cost pricing is fundamental to the fairness for both QFs and utility ratepayers. As such it is important to examine the appropriate methodology for calculating avoided costs as a longer-term issue. Staff believes the current methodology may not reflect market realities. The process to incorporate changing technology and market conditions should be thoroughly reviewed in developing an avoided cost methodology. There are issues that need to be fully examined in order to ensure PURPA implantation is fair, transparent, and flexible enough to adapt to such transformations.

There is a major transformation underway in the market, as the industry transitions to more open markets we will need to see what impact it will have on appropriate avoided cost pricing. Issues such as EIM impacts would be considered here.

Parties have made several suggestions for improving avoided cost pricing, including examining the results of an RFP, treatment of transmission costs, and valuing capacity. Staff believes any change to the current methodology should go through a rigorous analysis prior to implementation.

Staff proposes to examine alternative methodologies for setting avoided costs. Depending on the results of the investigation the outcome could range from minor tweaks, to a complete methodological changes. Other questions to examine may include:

(1) Should all or some QFs (i.e., existing QFs) have the option for levelized prices during the fixed-price term?

(2) Should utilities be allowed to use a modeling approach to determine non-standard prices?

(3) Should there continue to be both renewable and non-renewable price streams?

(4) Should variable QFs with storage be allowed access to baseload QF pricing?

(5) What are the implications of renewable pricing less than non-renewable pricing?

(6) Should renewable QFs be allowed to take non-renewable prices and keep the associated RECs in the case of a price inversion?