BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1129

In the Matter of PUBLIC UTILITY COMMISSION OF OREGON Staff's Investigation Relating to Electric Utility Purchases From Qualifying Facilities.	STAFF'S REPLY BRIEF Phase II /Track II

I. INTRODUCTON

Staff requested the Commission open Docket UM 1129 to address the lack of Qualifying Facility (QF) development in Oregon and to explore changes that would encourage QF development without harming utilities and their customers. Staff's recommendations for resolving issues in this proceeding have been offered with an objective of "ensur[ing] that QFs have a fair opportunity for development or continuation of their projects, consistent with the law." *See* Staff Opening Brief, Phase I, at 3; Transcript (TR) at 184 (Breen).

Idaho Power asserts that staff has "at times encouraged the Commission to adopt policies that seek to grant advantages to the QFs to the detriment of the utility customers." *See* Idaho Power Opening Brief at 15. Portland General Electric (PGE), on the other hand, states that "Staff has shown in this docket that it is attempting to balance promotion of QF interests with the potential for harm to a utility and its customers…." *See* PGE Opening Brief at 16.

Staff has worked diligently to achieve this balance in its recommendations for power purchases from both small and large QFs and in carrying out the Commission's directives in Order No. 05-584. In this reply brief, Staff will only address selected issues and for any issue not specifically discussed, staff stands by its testimony and its opening brief as its response.[1]

///

[1] For the issues discussed in this Reply Brief, Staff will use the issue numbers as set forth in the adopted Issues List.

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 378-6322 / Fax: (503) 378-5300

II. THE ISSUES

1. Development of negotiation parameters and guidelines for nonstandard QF contracts

PGE asks how to reconcile staff's specific recommendations regarding negotiating guidelines with witness Schwartz's statement that staff's proposed guidelines "are not intended to limit the terms and conditions the utilities can negotiate for PURPA contracts." *See* PGE Opening Brief at 10; Staff/1800, Schwartz/8-9.

The answer is simple. The Commission ordered a second phase of Docket UM 1129 largely to further explore parameters and guidelines for the negotiation of non-standard contracts. In doing so, the Commission declared its intent "to provide maximum incentives for the development of QFs of *all* sizes, while ensuring that ratepayers remain indifferent to QF power having utilities pay no more than their avoided costs." *See* Order No. 05-584 at 11 (emphasis in original). Staff does not believe the Commission intended to strictly limit what the utilities and QFs could negotiate.

PGE further states that "Strictly defining parameters and guidelines for nonstandard contracts (beyond those parameters and guidelines as set forth in the FERC rules) in effect makes these contracts standardized, and not negotiated." *See* PGE Opening Brief at 5. It is staff's view that while the Commission intended to provide flexibility for the utilities and QFs to negotiate, the Commission also intended to provide more guidance and transparency in the negotiation process.

Staff agrees with ICNU and Weyerhaeuser that the FERC adjustment factors do not provide sufficient detail on how to adjust the standard avoided costs for a particular QF to facilitate the negotiation process. *See* ICNU-Weyerhaeuser Opening Brief at 6. Staff's proposed guidelines are just that – guidelines. A utility would not be prohibited from negotiating a QF contract with alternative provisions, such as those based on the QF's operational preferences, which depart from the guidelines the Commission adopts in this proceeding. However, the

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 378-6322 / Fax: (503) 378-5300

1 utility may be required to justify such a provision when it seeks to put the QF resource in rates,
2 or in any complaint by a QF that the utility did not offer contract provisions consistent with the
3 guidelines.

4 **b. How should QF power supply commitments differentiate between "as available"**
5 **and "legally enforceable obligations" for delivery of energy and capacity?**

6 PacifiCorp dismisses staff's argument that "as available" QFs should receive market-
7 based pricing because the proposal complies with federal PURPA regulations. *See* PacifiCorp
8 Opening Brief at 3. Indeed, market-based pricing is aligned with FERC rules which require
9 pricing for as-available QFs to be based on the utility's avoided cost *at the time of delivery*. *See*
10 Staff/1900, Chriss/2-3; Staff Opening Brief at 3. PGE has used quarterly projections of forward
11 market prices for the large non-firm Covanta Marion QF for some time. *See* Staff/2400, Chriss/4-
12 5. Further, PGE offers a market-based option for small QFs (the Dow Jones index rate) that do
13 not wish to make a firm supply commitment, and Idaho Power has asked the Commission to
14 approve its proposed market index rate for small QFs (Idaho Power Exhibit 302).

15 PacifiCorp's proposal to use its energy-only rate, filed every two years, is not consistent
16 with 18 CFR § 292.304(d)(1).

17 As to PacifiCorp's assertion that staff did not give other reasons why market-based
18 pricing is appropriate for non-firm deliveries, staff witness Chriss fully described its benefits for
19 the utility and ratepayers in Phase I of this proceeding. To reiterate: 1) a market index option
20 allows the utility to purchase QF power at the price that most likely represents the utility's
21 opportunity cost, 2) market prices give QFs an incentive to produce during the highest-price
22 periods when the power is most valuable to the utility, and 3) during off-peak hours market
23 prices may be lower than the filed avoided energy cost rate. *See* Staff/700, Chriss/7-8.

24 ///

25 ///

26 ///

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 378-6322 / Fax: (503) 378-5300

c. How should "firm" or "non-firm supply commitments be defined and differentiated through contractual default and damages provisions?

ICNU and Weyerhaeuser characterize staff's position on firm supply commitments as follows: "QFs are generally considered firm resources, unless the contract specifically states otherwise." *See* ICNU-Weyerhaeuser Opening Brief at 32. This is an oversimplification of staff's stated position. Staff interprets 18 C.F.R. § 292.304(d)(2) as follows: Avoided cost rates are based on a firm proxy utility resource. If sanctions for noncompliance in the negotiated QF contract "provide energy or capacity pursuant to a legally enforceable obligation for the delivery of [a specified amount of] energy or capacity over a specified term," it is a contract for firm power.

d. How should avoided costs be adjusted for factors, such as those described in 18 CFR § 292.304, for a Qualifying Facility's specific power supply attributes and commitments?

Reliability and Dispatchability

In their Opening Brief, ICNU and Weyerhaeuser state their agreement with staff that the QF's actual availability should be compared to the assumed availability of the utility proxy plant – not improvements over the QF's contracted capacity level – in determining related adjustments to avoided costs for large QFs. PacifiCorp also holds this view. Further, ICNU and Weyerhaeuser find reasonable staff's proposed sliding scale model to calculate adjustments to capacity payments for actual monthly QF performance. *See* ICNU-Weyerhaeuser Opening Brief at 12-13; Staff Opening Brief at 5-6, 12; Staff/2300, Schwartz/5-8; PPL/404, Griswold/5.

Staff proposes the sliding scale model be used for PGE and PacifiCorp to adjust for inferior or superior availability of the QF during peak hours, compared to the utility proxy plant. However, such an adjustment should be made only during the utility's resource deficiency period, when the proxy plant serves as the basis for avoided costs. Because such an adjustment does not reflect the reduced value of a "24/7" (non-dispatchable) natural gas-fired combined heat and power (CHP) facility, compared to the utility proxy plant, staff continues to recommend that

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 378-6322 / Fax: (503) 378-5300

1 the QF's reduced value relative to the proxy plant be estimated through modeling with stochastic
2 parameters, such as that used for the utility's Integrated Resource Plan (IRP). Staff described in
3 testimony how such an analysis could be used for this adjustment. *See* Staff/1800, Schwartz/11;
4 Staff/2300, Schwartz/9-10; Staff Opening Brief at 7, and Attachment A, pages 1-2.

5 Idaho Power requests that the Commission allow the company to use the IRP
6 methodology approved by the Idaho Public Utilities Commission (IPUC) for calculating avoided
7 cost rates when negotiating with large QFs. ICNU and Weyerhaeuser have raised concerns that
8 Idaho Power has used this methodology to calculate avoided cost rates for large QFs that are
9 significantly lower than the standard rates. Staff noted that the Idaho Commission-approved
10 methodology may be a deviation from Oregon Order No. 05-584 which states (at 12 and 59) that
11 standard avoided cost rates serve as a starting point for negotiations with large QFs. If the
12 Commission is inclined to grant Idaho Power's request (and staff would not object), staff
13 recommends the company be required to incorporate stochastic analysis of electric and natural
14 gas prices, loads, hydro and unplanned outages. Idaho Power appears willing to do so. *See* Idaho
15 Power/400, Gale-Allphin/9-11; Idaho Power Opening Brief at 5-7; Staff/2300, Schwartz/16-17;
16 Staff/2301, Schwartz/8-9; Staff Opening Brief at 12-13.

17 ICNU and Weyerhaeuser recommend the Commission reject use of such IRP modeling
18 because it would make it difficult for QFs to verify whether the reductions the utility proposes in
19 standard avoided cost rates are appropriate. *See* ICNU-Weyerhaeuser Opening Brief at 13-14.
20 Although the utilities' IRP models are vetted in a public process, staff generally agrees with
21 ICNU and Weyerhaeuser that such verification could prove difficult for the QF.

22 PacifiCorp also rejects staff's proposal to require the utilities to perform IRP-type
23 stochastic modeling. The company finds it "unnecessarily burdensome and time consuming"
24 and contrary to a goal of timely turnaround on indicative pricing proposals. *See* PacifiCorp
25 Opening Brief at 7-8. To reduce that burden and improve turnaround time, PacifiCorp and PGE
26 could develop a *standard* avoided cost adjustment that reflects the reduced value, compared to

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 378-6322 / Fax: (503) 378-5300

1 the utility proxy plant, of a large non-dispatchable CHP facility which could be applied to all
2 such QFs. Regarding the assumed facility size for such an analysis, staff notes that PacifiCorp
3 previously used a 50 average megawatt QF unit to estimate avoided costs during the company's
4 resource sufficiency period. *See* Staff/100, Breen/16-17.

5 The Commission could direct the parties to further develop such a modeling approach.
6 Alternatively, the Commission could require each utility to submit, as part of its filing made in
7 compliance with the Commission's order in the Phase II proceeding, a proposed modeling
8 approach and modeling results for review by staff and the parties.

9 Turning to the payment structure for large dispatchable QFs, Idaho Power recommends
10 the Commission allow the company to pay avoided costs using a bundled rate that includes both
11 energy and capacity value. *See* Idaho Power/400, Gale-Allphin/6-8; Idaho Power Opening Brief
12 at 7-9. Staff agrees with ICNU and Weyerhaeuser that QF contracts for firm power may provide
13 strong incentives for high reliability through fixed capacity payments, separate from energy
14 payments. For firm QFs relying on intermittent resources such as wind, staff recommends that
15 utilities negotiate bundled rates (all-in price per megawatt-hour). *See* Staff/1800, Schwartz/11,
16 14; Staff/2300, Schwartz/7; Staff Opening Brief at 8-9 and Attachment A, guidelines 15-16;
17 ICNU-Weyerhaeuser/300, Beach/12; ICNU-Weyerhaeuser Opening Brief at 9.

18 Staff's understanding is that the negotiating parameters the Commission will adopt will
19 serve as guidelines during the negotiation process. A utility would not be prohibited from
20 negotiating a bundled energy/capacity rate with a dispatchable QF. At the same time, if the
21 Commission adopts the guideline staff and ICNU-Weyerhaeuser recommend regarding fixed
22 capacity payments for firm dispatchable QFs, the utility should be willing to accept that
23 provision so long as the QF agrees to default, security and damage provisions that would keep
24 the utility whole in the event the QF did not meet its capacity obligations under the contract.

25 ///

26 ///

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 378-6322 / Fax: (503) 378-5300

1 *Termination*

2 Staff recommended the Commission impose on large QFs the same conditions regarding
3 termination as staff recommended for small QFs in the Phase I Compliance portion of this
4 proceeding with the exception that the Commission should not prescribe the time period over
5 which the utility may seek termination damages. *See* Staff/1000, Schwartz/36-38, 41-43, 48-49;
6 Staff/1500, Schwartz/21-22; Staff/1800, Schwartz/12; Staff Opening Brief at 8. Staff's Opening
7 Brief included a list of proposed guidelines for the negotiation of large QF power purchases
8 (Attachment A), pursuant to Administrative Law Judge Kirkpatrick's memo dated May 4, 2006.
9 Among the guidelines related to termination was the following (guideline 32): "Delay of
10 commercial operation should not be a cause of termination or related damages if the utility
11 determines at the time of contract execution that it will be resource-sufficient as of the QF on-
12 line date specified in the contract."

13 Staff believes that this provision is consistent with Order No. 05-584 (at 47) which
14 indicates that the Commission found the utility and its customers likely would not be harmed by
15 a delay in QF commercial operation if a utility is resource-sufficient. In addition, if the utility is
16 resource-sufficient, there may be an advantage to the utility and its ratepayers if the QF project is
17 delayed, particularly if market prices are low. *See* Staff/1000, Schwartz/32-33; Staff Opening
18 Brief at 6.

19 On reflection, unlike a small QF, a large QF could have a sizable impact on the utility's
20 projected net position (load/resource balance). Thus, depending on QF size, a utility may take
21 action in advance of a large QF's expected on-line date to make additional sales or reduce
22 purchases if the utility expects to be resource-sufficient as of that date. While damages may be
23 appropriate for a large QF in such a case, staff continues to believe that termination is not
24 appropriate, unless the actual on-line date departs significantly from the date in the contract.

25 ///

26 ///

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 378-6322 / Fax: (503) 378-5300

1 *Line Losses and Transmission Savings*

2 ICNU and Weyerhaeuser are willing to accept PacifiCorp's proposal for adjusting
3 avoided cost rates for line losses if it is clear that the determination will be based on the
4 difference between two factors: 1) the distance between the QF and the load area it would
5 actually serve and 2) the distance between the utility proxy plant and the load area it would
6 serve. Further, ICNU and Weyerhaeuser recommend the QF have the option of requesting the
7 utility perform a line loss study to obtain a more accurate adjustment. *See* ICNU-Weyerhaeuser
8 Opening Brief at 16-17.

9 On reflection, staff agrees with ICNU and Weyerhaeuser that PacifiCorp's testimony is
10 unclear regarding the load center(s) that would be used to determine relative line losses for the
11 QF, compared to the utility proxy plant. In testifying that PacifiCorp's proposed method for line
12 loss adjustments is reasonable, staff witness Schwartz assumed that, in determining line losses
13 for the QF, the company would use the load center that the QF power would *actually* serve, not
14 the Utah load center that the Utah proxy plant would serve.

15 Staff agrees with ICNU and Weyerhaeuser that in making the line loss adjustment, the
16 utility should not assume the QF's power would be wheeled to a load center closest to the utility
17 proxy plant. Staff shares ICNU and Weyerhaeuser's view that such an adjustment would ignore
18 how the power would actually be used and the actual line losses the utility would incur or avoid.
19 Therefore, such an adjustment would inappropriately impose a high penalty on Oregon QFs for
20 line losses, ignoring the benefits of QFs sited close to customer loads – a distinct advantage some
21 QFs provide compared to remotely sited utility plants. With this clarification, staff continues to
22 agree with PacifiCorp that its proposed methodology serves as a reasonable proxy in lieu of
23 performing individual calculations. *Id. Also see* PPL/407, Griswold/2-6; PacifiCorp Opening
24 Brief at 6-7; Staff/1800, Schwartz/14-15; Staff/2300, Schwartz/11; and Staff/2301, Schwartz/3.

25 ICNU and Weyerhaeuser state that large QFs should receive a pro rata share of any
26 transmission savings to which they contribute. *See* ICNU-Weyerhaeuser Opening Brief at 18.

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 378-6322 / Fax: (503) 378-5300

1 This is consistent with staff's position on the aggregate value of QFs on the utility's system and
2 the relationship of the availability of QF power to the ability of the utility to avoid costs. *See*
3 Staff Opening Brief at 10-11.
4 *QF Aggregate Value, Smaller Capacity Increments and Shorter Lead Times*
5 Staff generally agrees with ICNU and Weyerhaeuser's recommendation that the
6 Commission not adopt *specific* guidelines that will adjust the avoided costs for large QFs for two
7 of the FERC adjustment factors: 1) the individual and aggregate value of QFs on the utility's
8 system and 2) smaller capacity increments and shorter lead times for QFs. At the same time,
9 ICNU and Weyerhaeuser note that if the Commission decides to use IRP modeling to value
10 dispatchability, the Commission should require the modeling to take these factors into account.
11 Staff and parties did not recommend a definitive method for making adjustments for
12 these FERC factors. Staff's proposed guidelines simply state that, consistent with federal
13 PURPA requirements, the utility may use its resource planning or production cost models to do
14 so. Staff also stated that the QF should receive no more of the aggregate value than the
15 incremental value it contributes.
16 Staff further agrees with ICNU and Weyerhaeuser that the Commission should take these
17 FERC factors into account in determining whether 1) QFs should have the opportunity to earn
18 additional capacity payments for superior availability compared to the utility proxy plant (staff
19 find this appropriate so long as the superior performance is within the QF's contracted capacity
20 level) and 2) QFs should be compensated for their contribution to avoided transmission costs,
21 beyond line losses. *See* ICNU-Weyerhaeuser Opening Brief at 21-23; Staff Opening Brief at 9
22 and Attachment A, guidelines 17-18.
23 ///
24 ///
25 ///
26 ///

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 378-6322 / Fax: (503) 378-5300

f. Can the utilities adjust the avoided cost calculations for Qualifying Facilities over 10 MW based on factors that have not been approved by the Oregon Public Utility Commission?

In its Opening Brief, Idaho Power states, "In 18 CFR §292.304(e), the Federal Energy Regulatory Commission ("FERC") provides a comprehensive (if not exclusive) list of factors which 'shall, to the extent practicable, be taken into account' in determining avoided cost rates for QF contracts." PGE states in its Opening Brief that it "believe[s] that the FERC list is comprehensive." In their Opening Brief, ICNU and Weyerhaeuser state, "It is unclear whether the Commission has authority to allow the utilities to use additional non-FERC approved factors to adjust their avoided costs," and "Allowing the utilities to unilaterally create additional avoided cost factors to adjust their avoided costs is inconsistent with the purpose of this proceeding…." *See* Idaho Power Opening Brief at 2; PGE Opening Brief at 11; ICNU-Weyerhaeuser Opening Brief at 23-24.

PacifiCorp, however, continues to argue that the FERC factors for adjusting avoided cost rates do not constitute an all-inclusive list. *See* PacifiCorp Opening Brief at 5-6. Even if that were true, which staff does not concede, PacifiCorp ignores staff's additional argument that the Commission ordered a second phase of this proceeding in large part to determine the negotiation parameters and guidelines for nonstandard QF contracts, including adjustments to standard avoided cost rates. The utilities and other parties have had 2-1/2 years to raise in Docket UM 1129 any adjustment factors that should be considered in determining avoided cost rates for QFs. If a utility has not raised any such factor in all this time for consideration in the proceeding the Commission established to review such issues, the utility should not be allowed at a later date to devise a new way to reduce payments to QFs. *See* Staff/1800, Schwartz/15-16; Staff/2300, Schwartz/13; Staff Opening Brief at 15.

///

///

///

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 378-6322 / Fax: (503) 378-5300

2. In the event of the inability of a QF to establish creditworthiness, determination of an appropriate amount of default security to be required.

Staff proposes the Commission mandate the same default security requirements for large QFs that are unable to establish creditworthiness as it recommended for QFs eligible for a standard contract. These requirements, which are selected at the QF's discretion, are: senior lien, step-in rights, a cash escrow or a line of credit. *See* Order No. 05-584 at 45. The Commission declined to set an amount of default security and left this to the utility's discretion as provided in its standard contract. *Id.*

PacifiCorp's standard contract amount is based on an average 12 months of replacement power costs over the term of the contract. However, for large QFs the company proposes that unless agreed to by both parties in writing, the required default security will be an amount sufficient to replace a minimum of 12, and a maximum of 36, average months of replacement power over the term of the contract (based on the amount of time expected to replace the large QF resource with forward market purchases). *See* PPL/303, Wessling/2; PacifiCorp Opening Brief at 11-12.

Upon further review, staff does not object to PacifiCorp's 36-month cap proposal in concept. However, in deciding upon the number of months to use in a particular case, the company should take into account the risk associated with the particular QF based upon such factors as its size and the type of supply commitments the QF is making. Staff would not expect the default security provisions for large QFs to be more onerous than for the company's non-PURPA agreements for similar types of power transactions.

3. Further exploration of how the calculation of avoided cost should reflect the nature and quality QF energy. Specifically:

a. How should firm vs. non-firm commitments and integration of intermittent resources affect the calculation of avoided costs?

Integration costs are minimal at low levels of wind in a utility control area and are significantly higher at high wind penetration levels. That makes it particularly inappropriate for

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 378-6322 / Fax: (503) 378-5300

1 utilities to use a long-term planning goal, such as PacifiCorp's 1,400 MW target, to adjust
2 avoided costs for integration. *See* Staff Opening Brief at 16-19.
3 PacifiCorp says that conceptually, it is not opposed to staff's proposed approach to
4 determining integration costs for large intermittent resources such as wind. *See* PacifiCorp
5 Opening Brief at 8. However, the company continues to mischaracterize staff's proposal.
6 First, the company wrongly asserts that staff's approach would require "individual IRP
7 modeling analyses for each proposed intermittent QF project over 10 MW." Second, the
8 company incorrectly describes staff's approach as one that "base[es] the determination on only
9 the cost of integration into the existing system of the utility." *Id.*
10 On the first point, staff simply proposes that the utility use the most recent wind
11 integration cost curve developed for its system (by control area), as it is updated over time for
12 resource planning, competitive bidding and consideration of utility-built projects. In fact, the
13 only thing project-specific about staff's proposal is that the proposed QF would be included in
14 the amount of wind the utility expects to acquire over the next five years and, therefore, the
15 utility's estimated integration costs based on that same cost curve. As Idaho Power has noted,
16 acquisition of wind QFs may offset other utility wind acquisitions. *See* Idaho Power/300,
17 Gale/10. When you consider that some "large" wind QFs will not be very large, the large wind
18 QF at hand may not be a material addition to the utility's five-year wind acquisition plan.
19 On the second point, staff's proposal would take into account the level of wind resources
20 the utility expects to acquire in each control area over a five-year period. In this regard, it is well
21 balanced between a strict adherence to the prudence standard, which would consider only known
22 and measurable resources (the wind resources already in place in the control area), and the
23 utility's long-term plan for acquiring wind resources, which may never come to pass.
24 PGE disagrees with staff's proposal to limit the amount of wind resources used to
25 determine integration costs to the amount the utility plans to acquire over the next five years.
26 The company simply states that the five-year limit "does not align with prudent future planning

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 378-6322 / Fax: (503) 378-5300

for integrating additional such resources." *See* PGE Opening Brief at 12. In response, staff reiterates that planned resource actions beyond the first five years of a utility's IRP Action Plan are highly unreliable. Further, staff views its proposal as going beyond the normal prudence standard, so as not to provide a disincentive to the utility to acquire additional wind resources. *See* Staff/1800, Schwartz/22-28; Staff/2300, Schwartz/17-18.

4. Further exploration of a Mechanical Availability Guarantee (MAG). For example, are avoided cost prices affected by a Mechanical Availability Guarantee?

Staff proposes that for QFs that rely on intermittent renewable resources, the utilities be required to include a Mechanical Availability Guarantee (MAG) in the standard contract that serves as the small QF's minimum delivery commitment. For large QFs, staff proposes that the utilities be allowed to negotiate a MAG or another type of minimum delivery commitment.

PGE asserts that a MAG "should not necessarily be substituted for an actual supply commitment." *See* PGE Opening Brief at 13. Staff and PacifiCorp disagree with the view that a MAG is not an actual supply commitment. The delivery commitment under a MAG is based on fixed percentages of the QF's *full* output when wind and water are available, except for excused events such as too much or too little wind or water, scheduled maintenance and force majeure. Under standard contracts today, the supply commitment is based on the predicted output under *worst-case* motive-force conditions. *See* Staff/1800, Schwartz/29-33; Staff/2300, Schwartz/15-16; Staff Opening Brief at 20-23; PPL/404, Griswold/15-19; PPL/407, Griswold/1. PacifiCorp Opening Brief at 12-13.

5. Further exploration of market pricing options and alternatives to using nameplate capacity to determine the size of a QF project for standard contract eligibility purposes

In its Order, the Commission designated a natural gas-fired CCCT as the avoided resource when PGE or PacifiCorp are resource deficient. *See* Order No. 05-584 at 27. The Commission further recognized that Idaho Power also uses input and cost variables that are associated with a surrogate CCCT. The Commission's determination to use a CCCT as the

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 378-6322 / Fax: (503) 378-5300

1 avoided resource was correct at the time the Commission issued its Order. However, the
2 Commission should recognize that in the future, a utility's avoided resource, based on its
3 acknowledged Integrated Resource Plan, could be a coal plant, wind plant or other resource. *See*
4 Phase I TR at 240 (Schwartz).

5 Along this line, ICNU-Weyerhaeuser state they agree in theory with Idaho Power that a
6 utility "should only be required to offer a gas price index option if the utility has selected a gas-
7 fired resource as its proxy plant." *See* ICNU-Weyerhaeuser Opening Brief at 31. Staff agrees as
8 well. If the Commission is to set a utility's avoided costs on the costs that are actually being
9 avoided, the price of natural gas becomes moot if the avoided resource during the deficiency
10 period is coal or wind. As such, it may be appropriate in future avoided cost filings for the utility
11 to forgo offering the natural gas pricing options for the resource deficiency period. It is
12 important to note that this discussion does not affect any market pricing option based on the
13 electricity market, such as PGE's Dow Jones Mid-Columbia Daily On- and Off-Peak Electricity
14 Firm Price Index and Idaho Power's proposed Schedule 86. Such options are still appropriate
15 offerings even with a change in the avoided resource.

16 **a. Should PacifiCorp offer a market pricing option? [Order No. 05-584 at 35]**

17 PacifiCorp continues to resist staff's recommendation that it offer a power market index
18 rate option for its standard contracts. The company argues that "parity with PGE" should not be
19 used as a reason for requiring the pricing option because "parity with Idaho Power, which does
20 not have such a pricing option, would equally dictate that PacifiCorp should *not* offer the
21 option." PacifiCorp Opening Brief at 15 (emphasis in original).

22 While the point about "parity with Idaho Power" is not of overwhelming importance to
23 staff's position, PacifiCorp's statement is in any event incorrect. Idaho Power in fact asked the
24 Commission to approve its proposed market index pricing option for non-firm QFs 10 MW or
25 less as shown by Idaho Power's Exhibit 302.

26 ///

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 378-6322 / Fax: (503) 378-5300

Staff reiterates above the benefits of a market pricing option for the utility and its ratepayers. Such a rate also benefits QFs that prefer to make minimal supply commitments, as well as those that are able to reduce on-site load to enable additional power sales to the utility when market prices are high (and when the power is most valuable to the utility). *See* Staff/700, Chriss/7-8.

7. Liability insurance for QFs with a design capacity at or under 200 kW.

Phase II includes one insurance issue, which is "Liability insurance for QFs with a design capacity at or under 200 kW."

In its Opening Brief, Idaho Power focuses on two issues:

1) In terms of risk, facility size does not matter; and
2) Although the cost of liability insurance may be more difficult to bear for smaller QFs, it is not a barrier to smaller QFs entering contracts.

See Idaho Power Opening Brief at 13.[2]

Idaho Power omits three other arguments presented by staff. These arguments are:

1) Potential costs and relative risk compared to net metering facilities;
2) Actions by other jurisdictions; and
3) Indemnification clauses of contracts.

Idaho Power's argument about risk and facility size is unpersuasive. Staff witness Breen pointed out that "no utility was able to provide an example where it was liable for damages because of the actions of a QF." *See* Staff/100, Breen/10. Although, Idaho Power argued in its UM 1129 Opening Brief that it was aware of several instances on its system where QFs have maintained dangerous conditions that *could* have resulted in serious personal injury or property damage, Idaho Power failed to provide any information about these instances. *See* Idaho Power Opening Brief at 14. Additionally, the Commission has no records to support Idaho Power's claim about several potential dangerous situations concerning QF interconnections with the Idaho Power system.

[2] In Staff/2600, Dougherty/2, Staff used a 33 percent capacity factor, which would be the capacity factor for an exceptional wind project.

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 378-6322 / Fax: (503) 378-5300

1 Idaho Power also states that it has contracts with 11 QFs whose design capacity is 200
2 kW or less. *See* Idaho Power Opening Brief at 13. Idaho Power's inability to provide an
3 example where it was liable for damages because of the interconnection actions of a small QF
4 indicates a low level of risk resulting from the operations of a small QF.
5 When addressing revenues that a small QF could receive under Idaho Power's Oregon
6 Schedule 85, Option Pricing 1, Idaho Power consistently uses a 200 kW facility at an 85 percent
7 capacity factor for illustrative purposes. *See* Idaho Power Opening Brief at 14. However, Idaho
8 Power ignores the fact that wind projects have a capacity factor of about 30 percent and run of
9 the river projects have capacity factors of approximately 40 percent.[3] So even though Idaho
10 Power attempts to paint its argument where the best case scenario is the norm, staff's table
11 comparing revenues and insurance costs shows a less positive picture. In staff's rebuttal
12 testimony, there are six illustrative scenarios where the estimated cost of insurance equals or
13 exceeds the possible revenues a small QF would receive under Idaho Power's Oregon Schedule
14 85, Option Pricing 1. *See* Staff/2600, Dougherty/3.
15 As previously mentioned, Idaho Power does not address staff's argument about potential
16 costs and relative risk compared to net metering facilities. Oregon has very specific net metering
17 statutes and rules. As staff has consistently pointed out, ORS 757.300(4)(c) does not require net
18 metering facilities to purchase additional liability insurance. Staff witness Schwartz testified that
19 the 2005 Legislature in Senate Bill 84 gave the Commission the authority to increase the net
20 metering eligible facility size for PGE and PacifiCorp. *See* Staff/1500, Schwartz/4. In many
21 states, the eligible facility size for net metering is at or above 100 kW. *See* Staff/2101,
22 Dougherty/1-6.
23 If the Commission, as a result of any rulemaking, was to increase the size of net metering
24 facilities to 200 kW, there could be, depending upon the Commission's resolution of this issue,
25
26 [3] In Staff/2600, Dougherty/2, Staff used a 33 percent capacity factor, which would be the capacity factor for an exceptional wind project.

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 378-6322 / Fax: (503) 378-5300

disparate treatment concerning liability insurance requirements for net metering facilities and those for small QFs at or under 200 kW under PURPA power purchase agreements. If the size of net metering facilities is increased, it is plausible that a larger net metering facility would not be required to maintain liability insurance, while a smaller QF under a PURPA power purchase agreement would have to show proof of insurance.

Idaho Power also does not address staff's argument concerning actions in other jurisdictions. Many states do not impose an insurance requirement on small QFs. *See* Staff/2100, Dougherty/11. As a result, Oregon would not be the first state to relieve small QFs of the burden of additional liability insurance if staff's position is adopted.

Finally, Idaho Power ignores the fact that any prudent contract would have indemnification language that each party would agree to hold harmless and to indemnify against all loss, damage, fines, penalties, expense, and liability to third persons for such instances as injury, death, or property damage.[4] The indemnification clauses, if pursued aggressively by the utilities, are sufficient legal remedies and adequately protect the interest of the utility, its customers, and small QFs.

In summary, the Commission should not allow the utilities to impose mandatory liability insurance for small QFs under 200 kW.

11. Should competitive bidding be used to set pricing for Qualifying Facilities greater than a certain size (e.g., larger than 100 MW) if the utility has recently completed an RFP, or a bidding process is in progress or imminent? If so, how?

Staff recognizes the value of competitive bidding to inform the cost of the utility's proxy resource during the resource deficiency period. *See* Staff Opening Brief at 29-31.

PGE notes that "an RFP process may be useful in determining and calibrating an appropriate price, but should not necessarily be used in all circumstances because already available avoided cost information may be a reasonable proxy." *See* PGE Opening Brief at 16.

[4] Indemnification language for QFs up to 10 MW is stated in PacifiCorp's PPA Section 12; Idaho Power's PPA Section XI, 11.1; and PGE's Schedule 201, Qualifying Facility Power Purchase Information, Section 11.

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 378-6322 / Fax: (503) 378-5300

1 PacifiCorp continues to recommend the use of competitive bidding to set the terms,
2 conditions and price for capacity purchases from QFs 100 MW or larger with contract terms of
3 five years of more. *See* PacifiCorp Opening Brief at 16-17; PPL/404, Griswold/24-26. Further,
4 under the company's proposal, QFs would not receive a capacity payment unless they submit a
5 winning proposal in the utility's competitive bidding process. PacifiCorp clarified in its Opening
6 Brief that such capacity payments would not be made "at least during the period of resource
7 sufficiency." *Id.*

8 Even as clarified by PacifiCorp, staff continues to find PacifiCorp's proposal contrary to
9 PURPA, which requires that the utility pay avoided costs for all capacity offered by the QF, as
10 well as Order No. 05-584, which determined that capacity has value even during the utility's
11 resource sufficiency period.

12 ICNU and Weyerhaeuser oppose the use of competitive bidding in developing avoided
13 cost rates for QFs except in the utility's next avoided cost filing. This generally appears to be
14 consistent with, rather than contrary to, staff's position. However, rather than *requiring* the
15 utilities to update their avoided costs whenever they determine they need new long-term supply-
16 side resources, as ICNU and Weyerhaeuser recommend, the Commission already has determined
17 that utilities and other parties may notify the Commission when it may be appropriate to review
18 avoided cost rates between the two-year filing period. *See* ICNU-Weyerhaeuser Opening Brief at
19 35-36; Staff Opening Brief at 29-31; Order No. 05-584 at 29.

20 Further, it is unclear to staff exactly when the utility would be required to make an
21 avoided cost filing under ICNU-Weyerhaeuser's proposal. Historically, avoided cost filings
22 have been made immediately following acknowledgment of the utility's IRP. That is because
23 the IRP Action Plan sets out near-term resource needs and timelines. At the same time,
24 load/resource balances change over time, as do natural gas and market price forecasts. Such
25 changing circumstances support the Commission's decision regarding frequency of avoided cost
26 filings.

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 378-6322 / Fax: (503) 378-5300

12. Do provisions of the Energy Policy Act of 2005 affect the rules regarding new contracts with Qualifying Facilities? Specifically, should an Oregon electric company be required to enter into a new contract with a Qualifying Facility that is located in the service territory of an electric utility that has been relieved by FERC of a mandatory purchase obligation under PURPA?

PacifiCorp recommends the Commission consider the Energy Policy Act's "departure from the prior absolute mandate" of purchasing from QFs when balancing the dual objectives of promoting the development of QFs and ensuring ratepayer neutrality. *See* PacifiCorp Opening Brief at 18.

FERC has not completed its rules for relieving a utility from PURPA's purchase requirements. The rules appear to staff to be designed for areas with regional transmission organizations and more advanced markets than exist in the West. Until the rules are clear, and until the utility applies to FERC and receives an exemption from its mandatory purchase requirement under PURPA, the policy implications PacifiCorp suggests are not relevant.

PGE states that "a plain reading of the new statutory language in the 2005 Energy Policy Act suggests that PGE would not be required to purchase from out of service territory QFs to which the exemption applies." *See* PGE Opening Brief at 17. In other words, the issue is whether PGE is still required to purchase from a QF located in the service territory of another utility – say, PacifiCorp – when PacifiCorp has been exempted by FERC from PURPA's requirement to make a purchase from that QF (and PGE has not received such an exemption).

PGE's above-stated conclusion is flawed because the exemption is not tied to the QF but instead to the particular electric utility (PacifiCorp in the above example). As such, if PGE wants an exemption from PURPA's mandatory purchase obligation, it must apply to FERC for it, regardless of whether PacifiCorp has already received its own exemption. This interpretation is plain from the Notice that accompanied proposed rule 18 CFR § 292.310(a) (which requires "any utility" desiring relief from the mandatory purchase option to file its own application for an exemption). A copy of the Notice is attached as Exhibit A.

///

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 378-6322 / Fax: (503) 378-5300

14. How shall the standard form contracts for off-system QFs of PacifiCorp and PGE address where title to the power changes hands? Development of terms for standard off-system QF contracts, and development of negotiation parameters and guidelines for nonstandard off-system QF contracts to address issues related to the transfer of title to off-system power.

Staff does not agree with the positions taken by ICNU and Weyerhaeuser that the "Commission ... require the utilities to follow the general provisions of the standard off-system QF contracts when they offer large QFs off-system contracts," and that "the utility should identify the provision and provide an explanation to the large off-system QF of why a change in the standard off-system QF contract was made." The standard off-system contract for small QFs may provide a starting point for negotiating a contract for a large QF. However, utilities should not be required to identify and explain changes from provisions in the standard contract when negotiating with large QFs. *See* Staff Opening Brief at 13; ICNU-Weyerhaeuser Opening Brief at 36-37.

III. CONCLUSION

For the reasons stated, the Commission should adopt Staff's recommendations for all remaining disputed issues.

DATED this 12th day of July 2006.

Respectfully submitted,

HARDY MYERS
Attorney General

Michael T. Weirich, #82425
Assistant Attorney General
Of Attorneys for staff of the Public Utility Commission of Oregon

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 378-6322 / Fax: (503) 378-5300

• An area where the percentage of the population living in poverty is at least 20 percent;

• An area in a Metropolitan Area where the median family income is at or below 80 percent of the Metropolitan Area median family income or the national Metropolitan Area median family income, whichever is greater;

• An area outside of a Metropolitan Area, where the median family income is at or below 80 percent of the statewide non-Metropolitan Area median family income or the national non-Metropolitan Area median family income, whichever is greater;

• An area where the unemployment rate is at least 1.5 times the national average;

• An area meeting the criteria for economic distress that may be established by the Community Development Financial Institutions Fund (CDFI) of the United States Department of the Treasury.

In addition, the local community, neighborhood, or rural district must be underserved, based on data considered by the NCUA Board and the Federal banking agencies.

Once an underserved area has been added to a federal credit union's field of membership, the credit union must establish and maintain an office or service facility in the community within two years. A service facility is defined as a place where shares are accepted for members' accounts, loan applications are accepted and loans are disbursed. This definition includes a credit union owned branch, a shared branch, a mobile branch, or an office operated on a regularly scheduled weekly basis. This definition does not include an ATM or the credit union's Internet Web site.

The federal credit union adding the underserved community must document that the community meets the definition for serving underserved areas in the Federal Credit Union Act. The charter type of a multiple common-bond federal credit union adding such a community will not change. Therefore, the multiple common-bond federal credit union will not be able to receive the benefits afforded to low-income designated credit unions, such as expanded use of nonmember deposits and access to the Community Development Revolving Loan Program for Credit Unions.

A federal credit union that desires to include an underserved community in its field of membership must first develop a business plan specifying how it will serve the community. The business plan, at a minimum, must identify the credit and depository needs of the community and detail how the credit union plans to serve those needs. The credit union will be expected to regularly review the business plan to determine if the community is being adequately served. The regional director may require periodic service status reports from a credit union about the underserved area to ensure that the needs of the community are being met as well as requiring such reports before NCUA allows a multiple common-bond federal credit union to add an additional underserved area.

[FR Doc. E6–908 Filed 1–26–06; 8:45 am]

BILLING CODE 7535–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 292

[Docket No. RM06–10–000]

New PURPA Section 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities

Issued January 19, 2006.

AGENCY: Federal Energy Regulatory Commission, DOE.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is proposing to amend its regulations governing small power production and cogeneration in response to section 1253 of the Energy Policy Act of 2005 (EPAct 2005), which added section 210(m) to the Public Utility Regulatory Policies Act of 1978 (PURPA). The Commission seeks public comment on the amended regulations proposed herein.

DATES: Comments are due February 27, 2006. Reply Comments are due March 28, 2006.

ADDRESSES: Comments may be filed electronically via the eFiling link on the Commission's Web site at *http://www.ferc.gov*. Commenters unable to file comments electronically must send an original and 14 copies of their comments to: Federal Energy Regulatory Commission, Office of the Secretary, 888 First Street, NE., Washington, DC 20426. Refer to the Comment Procedures section of the preamble for additional information on how to file comments.

FOR FURTHER INFORMATION CONTACT:

Deborah Wyrick (Technical Information), Office of Energy Markets and Reliability, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, (202) 502–6113.

Marka Shaw (Technical Information), Office of Energy Markets and Reliability, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, (202) 502–8641.

Samuel Higginbottom (Legal Information), Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, (202) 502–8561.

Giuseppe Fina (Legal Information), Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426, (202) 502–8696.

SUPPLEMENTARY INFORMATION:

Before Commissioners: Joseph T. Kelliher, Chairman; Nora Mead Brownell, and Suedeen G. Kelly.

I. Introduction

1. On August 8, 2005, the Energy Policy Act of 2005 (EPAct 2005) [1] was signed into law. Section 1253(a) of EPAct 2005 adds a new section 210(m) to the Public Utility Regulatory Policies Act of 1978 (PURPA) [2] which provides for termination of an electric utility's obligation to purchase energy and capacity from qualifying cogeneration facilities and qualifying small power production facilities (QFs), if the Federal Energy Regulatory Commission (Commission) finds that certain conditions are met. Section 210(m) [3]: (1) Provides a procedure for an electric utility to file an application for relief from the mandatory purchase obligation on a service territory-wide basis; (2) provides a procedure for any affected entity or person to apply to the Commission for an order reinstating the electric utility's obligation to purchase energy; (3) provides for termination of an electric utility's obligation to sell to QFs energy and capacity if the Commission finds that certain conditions are met; (4) protects existing rights and remedies under any contract or obligation in effect or pending approval involving the purchase of energy or capacity or sale of energy or capacity to a QF; and (5) allows the Commission to issue and enforce

[1] Public Law 109–58, § 1253, 119 Stat. 594 (2005).

[2] 16 U.S.C. 824a–3 (2000).

[3] We note that the Commission has issued a notice of proposed rulemaking regarding added section 210(n) in Docket No. RM05–36–000. That section makes clear that no new qualifying cogeneration facility can enter into a contract with an electric utility unless the cogeneration facility satisfies criteria for new qualifying cogeneration facilities that will be established by the Commission. *Revised Regulations Governing Small Power Production and Cogeneration Facilities*, Notice of Proposed Rulemaking, 70 FR 60,456 (Oct. 18, 2005), FERC Stats. & Regs. ¶ 32,590 (2005).

regulations to ensure that an electric utility recovers all prudently incurred costs associated with the purchase of energy from a QF.

2. The Commission proposes to amend its regulations, specifically 18 CFR 292.303, to implement the requirements in section 210(m).[4] The Commission seeks public comment on the regulations proposed herein.

II. Background

3. When Congress enacted section 210 of PURPA, it required the Commission to prescribe rules as the Commission determined necessary to encourage cogeneration and small power production, including rules requiring electric utilities to offer to purchase electric power from and sell electric power to QFs. Additionally, section 210 of PURPA authorized the Commission to exempt QFs from certain federal and state laws and regulations.

4. Under section 201 of PURPA, cogeneration facilities and small power production facilities which meet certain standards and which are not owned by persons primarily engaged in the generation or sale of electric power[5] can become QFs, and thus become eligible for the rates and exemptions pursuant to section 210 of PURPA and found in our regulations.[6]

5. A cogeneration facility is defined in the Federal Power Act (FPA)[7] as a facility which produces electric energy and steam or forms of useful energy (such as heat) which are used for industrial, commercial, heating, or cooling purposes.[8] Thus, cogeneration facilities simultaneously produce two forms of useful energy, namely electric power and heat. Cogeneration facilities can use significantly less fuel to produce electricity and steam (or other forms of energy) than would be needed to produce the two separately.

6. Small power production facilities as defined in the FPA use biomass, waste, or renewable resources, including wind, solar energy and water, to produce electric power and have a power production capacity which, together with any other facilities located at the same site, are not greater than 80 megawatts.[9] Reliance on these sources of energy can reduce the need to consume fossil fuels to generate electric power.

7. Prior to the enactment of PURPA, a cogenerator or small power producer seeking to establish interconnected operation with a utility faced three major obstacles. First, utilities were not generally willing to purchase this electric output or were not willing to pay an appropriate rate for that output. Second, utilities generally charged discriminatorily high rates for back-up service to cogenerators and small power producers. Third, a cogenerator or small power producer which provided electricity to a utility's grid ran the risk of being considered a public utility and thus being subjected to extensive state and federal regulation.

8. Section 210 of PURPA was designed to remove these obstacles. Each electric utility is required under section 210 to offer to purchase available electric energy from cogeneration and small power production facilities which obtain qualifying status. The rates for such purchases from QFs must be just and reasonable to the ratepayers of the utility, in the public interest, and must not discriminate against cogenerators or small power producers. Rates also must not exceed the incremental cost to the electric utility of alternative electric energy (also known as the electric utility's "avoided costs"). Section 210 also requires electric utilities to provide electric service to QFs at rates which are just and reasonable, in the public interest, and which do not discriminate against cogenerators and small power producers.

9. Since Congress enacted PURPA, electric utilities have complained that their obligation to purchase from and sell to QFs, as implemented by the Commission in 18 CFR 292.303(a)–(b), was not economically beneficial and that they were purchasing energy they did not need and selling energy they did not want to sell. In 1995, the Commission clarified that in determining the avoided cost rate, the electric utility must take into account all alternative sources including third-party suppliers and does not have to buy power it does not need.[10] In the past decade, with the development of exempt wholesale generators (EWGs) introduced by the Energy Policy Act of 1992,[11] and increasing competition in wholesale electric markets as well as some retail electric markets, Congress has debated whether to repeal PURPA altogether, or to revise it. The result is new section 210(m), which is the subject of this rulemaking, and new section 210(n), which is being addressed in Docket No. RM05–36–000. New section 210(m) requires the Commission to lift the mandatory purchase obligation if it finds, in effect, that there is a sufficiently competitive market for the QF to sell its power. While the provision permits electric utilities to file applications for relief from the mandatory purchase obligation, and requires the Commission to act on such applications within 90 days, the Commission has determined that it can more appropriately address this issue through rulemaking.

III. Proposed Revisions to Regulations

A. Obligation To Purchase

10. Section 292.303(a) of the Commission's regulations, 18 CFR 292.303(a), states that:

> *Obligation to purchase from qualifying facilities.* Each electric utility shall purchase, in accordance with § 292.304, any energy and capacity which is made available from a qualifying facility:
> (1) Directly to the electric utility; or
> (2) Indirectly to the electric utility in accordance with paragraph (d) of this section.

11. The new PURPA section 210(m)(1) amends the obligation to purchase and states that:

> * * * no electric utility shall be required to enter into a new contract or obligation to purchase electric energy from a qualifying cogeneration facility or a qualifying small power production facility under this section if the Commission finds that the qualifying cogeneration facility or qualifying small power production facility has nondiscriminatory access to—
> (A)(i) Independently administered, auction-based day ahead and real time wholesale markets for the sale of electric energy; and (ii) wholesale markets for long-term sales of capacity and electric energy; or
> (B)(i) Transmission and interconnection services that are provided by a Commission-approved regional transmission entity and administered pursuant to an open access transmission tariff that affords nondiscriminatory treatment to all customers; and (ii) competitive wholesale markets that provide a meaningful

[4] We will generally refer to EPAct 2005's added section 210(m) of PURPA as "amended section 210." All other references to PURPA section 210 are as it currently exists.

[5] The ownership requirement was codified in sections 3(17)(A) and 3(18)(A) of the FPA. Section 1253(b) of EPAct 2005 removed the ownership requirement from sections 3(17)(A) and 3(18)(A) of the FPA, and the Commission has proposed to remove the ownership requirement from its regulations in Docket No. RM05–36–000. *Revised Regulations Governing Small Power Production and Cogeneration Facilities*, Notice of Proposed Rulemaking, 70 FR 60456 (Oct.18, 2005), FERC Stats. & Regs. ¶ 32,590 (2005).

[6] 18 CFR Part 292 (2005).

[7] 16 U.S.C. 824 *et seq.* (2000).

[8] 16 U.S.C. 796(18) (2000).

[9] 16 U.S.C. 796(17)(A)(i)–(ii) (2000).

[10] *Southern California Edison Company and San Diego Gas & Electric Company*, 70 FERC ¶ 61,215 at 61,677–78, *reconsideration denied*, 71 FERC ¶ 61,269 at 62,078 (1995) (finding that the determination of avoided cost must take into account "all sources").

[11] Energy Policy Act of 1992, Public Law No. 102–486, 106 Stat. 2776, (1993) (EPAct 1992). EPAct 1992 added a new section 32 to the Public Utility Holding Company Act of 1935 (PUHCA) to permit a category of sellers called EWGs to be exempt from PUHCA.

opportunity to sell capacity, including long-term and short-term sales, and electric energy, including long-term, short-term and real-time sales, to buyers other than the utility to which the qualifying facility is interconnected. In determining whether a meaningful opportunity to sell exists, the Commission shall consider, among other factors, evidence of transactions within the relevant market; or

(C) Wholesale markets for the sale of capacity and electric energy that are, at a minimum, of comparable competitive quality as markets described in subparagraphs (A) and (B).

Section 210(m)(1) thus relieves an electric utility of its obligation to enter into a new contract or obligation to purchase QF power upon a Commission finding that certain market conditions exist.

12. As discussed below, the Commission will: (1) Discuss its interpretation of the criteria for electric utility relief from the purchase obligation; (2) make a preliminary finding that QFs interconnected with utilities that are members of Midwest Independent Transmission System Operator, Inc. (Midwest ISO), PJM Interconnection, L.L.C. (PJM), ISO New England, Inc. (ISO–NE), and New York Independent System Operator (NYISO) have nondiscriminatory access to those markets and that those markets satisfy the section 210(m)(1)(A) criteria for removing the obligation of those electric utilities to enter into new contracts or obligations with QFs; and (3) provide guidance on the definition of "nondiscriminatory access," and "new contract or obligation."

1. Meaning of Section 210(m)(1)

13. Section 210(m)(1) states that no utility shall be obligated to enter into a new contract or obligation if the Commission finds that QFs have nondiscriminatory access to one of the three market circumstances described in section 210(m)(1)(A), (B), and (C). In effect, Congress has required the Commission to remove the mandatory purchase obligation if it finds that there is access to a sufficiently competitive market for QFs to sell their power. Based on this statutory language, in this section, we discuss our interpretation of what type of markets are required by section 210(m)(1) of PURPA to relieve a utility of the mandatory purchase obligation.

14. Subparagraph (A) waives the purchase obligation if QFs have nondiscriminatory access to (i) independently administered, auction-based day-ahead and real-time wholesale markets for the sale of electric energy; and (ii) wholesale markets for long-term sales of capacity and electric energy. We conclude that the most reasonable interpretation of subsection (A) is that it was crafted to apply in regions in which Independent System Operators (ISO) and Regional Transmission Organizations (RTO) administer day-ahead and real-time markets, and bilateral long-term contracts for the sale of capacity and electric energy are available to participants/QFs in these markets.

15. We note that the second prong of subparagraph (A) does not require auction-based long-term capacity or energy markets and such an interpretation would not be consistent with the statutory text. First, subparagraph (A)(ii) does not use the terms "organized," "independently administered," or "competitive" when describing the long term markets. As evidenced by subparagraph (B)(ii), discussed below, Congress could have imposed such requirements for the long-term wholesale markets, but did not. Therefore, we conclude that no such requirement was intended for the long-term markets of section 210(m)(1)(A)(ii). Second, unlike subparagraph (B)(ii), subparagraph (A)(ii) does not require the Commission to consider "evidence of transactions within the relevant market" when determining whether QFs have meaningful opportunities to sell into wholesale markets outside the host utility. This suggests that Congress presumed there was a meaningful opportunity to sell for QFs that have "nondiscriminatory access to" ISO and RTO regions with day-ahead and real-time markets.

16. A reasonable interpretation of subparagraph (B) is that it is intended to apply in non-auction-based markets because it waives the mandatory purchase requirement so long as there is (i) a Commission-approved regional transmission entity providing nondiscriminatory transmission and interconnection services; and (ii) "competitive wholesale markets" for short- and long-term energy and capacity sales and real-time energy sales. To meet subparagraph (B)(i), QFs must have nondiscriminatory access to transmission and interconnection service that is nondiscriminatory, which we interpret to mean access pursuant to a Commission-approved open access transmission tariff (OATT) and interconnection rules and provided by an entity that is regional in scope. Amended section 210 does not contain any express definition, and, therefore, the Commission has discretion in this context to deem an entity to be "regional" based on factors such as sufficient regional scope or configuration or the multiple discrete transmission systems it controls.

17. As to the second prong, subparagraph (B)(ii) requires that QFs have access to "*competitive* wholesale markets that provide a *meaningful opportunity*" to sell capacity and energy on both a short- and long-term basis and energy on a real-time basis (emphasis added). "Meaningful opportunity" is to be determined by the Commission after considering, among other factors, "evidence of transactions within the relevant market." Taken together, the terms "competitive," "meaningful opportunity" and "evidence of transactions" suggest that Congress intended that waiver occur in a non-auction-based market only if it could be established that QFs had opportunities to sell their output into competitive wholesale markets.

18. Subparagraph (C) removes the purchase obligation in wholesale markets for the sale of capacity and electric energy that are, "at a minimum," of comparable competitive quality as markets described in subparagraphs (A) and (B). Although this provision is not clear on its face, its reference to subparagraphs (A) and (B) requires the Commission to be mindful, in interpreting the provision, of the two types of requirements that are embodied in those sections, *i.e.*, (1) nondiscriminatory access to transmission and interconnection services, and (2) competitive short-term and long-term markets. These provisions appear to require a case-by-case approach, but we seek comments on whether the Commission can make generic findings on these provisions.

19. The Commission's existing OATT, adopted in Order No. 888,[12] and interconnection rules, adopted in Order Nos. 2003 [13] and 2006,[14] are designed to

[12] Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, FERC Stats. & Regs. Regulations Preambles January 1991-June 1996 ¶ 31,036 (1996), Order No. 888–A, FERC Stats. & Regs., Regulations Preambles July 1996–December 2000 ¶ 31,048 (1997), *order on reh'g*, Order No. 888–B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888–C, 82 FERC ¶ 61,046 (1998), *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).

[13] Standardization of Generator Interconnection Agreements and Procedures, Order No. 2003, 68 FR 49,845 (Aug. 19, 2003), FERC Stats. & Regs. ¶ 31,146 (2003), *order on reh'g*, Order No. 2003–A, 69 FR 15,932 (Mar. 26, 2004), FERC Stats. & Regs. ¶ 31,160 (2004), *order on reh'g*, Order No. 2003–B, 70 FR 265 (Jan. 4, 2005), FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g*, Order No. 2003–C, 70 FR 37,661 (June 30, 2005), FERC Stats. & Regs. ¶ 31,190 (2005).

[14] Standardization of Small Generator Interconnection Agreements and Procedures, Order

eliminate undue discrimination in the provision of transmission and interconnection services. Although the Commission recently issued a Notice Of Inquiry regarding changes to the OATT, the OATT has been considered sufficient to provide non-discriminatory access to transmission until such time as modified. Accordingly, we conclude that QFs have non-discriminatory access to transmission and interconnection if they have access to utilities providing service under an Order No. 888 OATT (or to utilities providing service under a Commission-accepted reciprocity tariff) and interconnection services pursuant to the Commission's interconnection rules. However, we seek comment on whether there are any circumstances in which an OATT should be considered insufficient for purposes of section 210(m). We also seek comment on whether a Commission-accepted reciprocity tariff filed by a nonjurisdictional electric utility has the same effect as an OATT for purposes of meeting section 210(m)(1)(C). We also seek comment on whether nonjurisdictional utilities provide nondiscriminatory interconnection services for purposes of section 210(m)(1)(C) of PURPA.

20. We also recognize that small QFs may be in a unique situation with respect to nondiscriminatory access because they interconnect with the host utility at a distribution level. For instance, Granite State has recently filed a petition in Docket No. EL06–26–000 asking the Commission to initiate a rulemaking implementing section 210(m) of PURPA and as part of that rulemaking, issue rules retaining the mandatory purchase obligation for small QFs (those with a nameplate capacity of 5 MW or less) and creating a rebuttable presumption in favor of retaining the mandatory purchase obligation for small power production facilities with a capacity over 5 MW and up to 20 MW. Granite State suggests that small hydro QFs do not have nondiscriminatory access to RTO/ISO markets. Therefore, we seek comment on whether the purchase obligation should be retained for small renewable projects and, if so, how to define "small," *e.g.*, 5 MWs or below, 20 MWs or below as proposed by Granite State. In addition, we seek comment on whether there may be other categories of QFs that lack nondiscriminatory access to RTO/ISO short-term or long-term wholesale markets for which we should retain the obligation to purchase.

21. With respect to whether the second prong of section 210(m)(B)(ii) is met in non-ISO/non-RTO markets, *i.e.*, whether QFs in non-ISO/non-RTO markets have access to wholesale markets for long-term sales of capacity and electric energy, would that prong be satisfied if there is a demonstration that an organized power procurement process exists in which QFs can participate (albeit not an auction-based process)? We seek comments on ways the prong may be satisfied.

2. Implementation of Section 210(m)(1)

(a) Subparagraph A

22. As we discussed above, the Commission interprets section 210(m)(1)(A) to apply in regions in which ISOs and RTOs administer day-ahead and real-time markets, and bilateral long-term contracts for the sale of capacity and electric energy are available to participants/QFs in these markets. The Commission proposes to find that the Midwest ISO, PJM, ISO–NE, and NYISO satisfy the requirements of section 210(m)(1)(A).[15] These entities are Commission approved ISO or RTOs that provide non-discriminatory open access transmission services and independently administer auction-based wholesale markets for day-ahead and real-time energy sales. Additionally, with respect to (A)(ii), the existence of bilateral long-term contracts for long-term sales of capacity and energy is an indication of a market. It is reasonable to conclude that the second prong of subparagraph (A) is met because bilateral long-term contracts are available to participants in the footprints of the Midwest ISO, PJM, ISO–NE, and NYISO. Therefore, we propose to find that electric utilities that are members of the Midwest ISO, PJM, ISO–NE, and NYISO would meet the requirements for relief from the mandatory purchase obligation. We describe these markets in more detail below.

(1) Midwest ISO

23. On December 20, 2001, the Commission found that the Midwest ISO satisfied the requirements, including independence from market participants, of Order No. 2000, and thus granted the Midwest ISO RTO status.[16] Thus, we believe that the Midwest ISO "independently administers" auction-based real-time markets. With respect to subparagraph (1)(A)(i), the Commission approved the Midwest ISO's proposed Transmission and Energy Markets Tariff (TEMT), which allowed the Midwest ISO to initiate Day 2 operations in its 15-state region.[17] The Midwest ISO's Day 2 operations include, among other things, day-ahead and real-time energy markets and a Financial Transmission Rights (FTR) market for transmission capacity. The Midwest ISO began Day 2 operations on April 1, 2005. Since market participants have access to the Midwest ISO's day-ahead and real-time energy markets to sell their electric energy, a QF that has "non-discriminatory access" would have the same opportunity. Also, bilateral contracts exist in the Midwest ISO for the long-term sales of capacity and energy. Accordingly, we would expect that such long-term sales would be available to all participants in the Midwest ISO's footprint. Based on the foregoing, we propose to find that the Midwest ISO meets the conditions of subparagraph (A).

(2) PJM

24. PJM received Commission approval as an independent regional transmission organization on July 12, 2001.[18] Since independence from market participants is one of four characteristics that PJM had shown for Commission approval to operate as an RTO, PJM satisfies the "independently administered" condition. Second, since 1997, PJM has operated auction-based, day-ahead and real-time wholesale energy markets pursuant to its OATT and Operating Agreement.[19] Because PJM's market participants have access to auction-based day ahead and real time wholesale energy markets, a QF would have the same opportunity as other generators to sell energy in that market. Also, there are bilateral contracts in PJM for the long-term sales of capacity and

No. 2006, 70 FR 34,100 (Jun. 13, 2005), FERC Stats. & Regs. ¶ 31,180 at 31,406–31,551 (2005), *order on reh'g*, Order No. 2006–A, 70 FR 71,760 (Nov. 30, 2005), FERC Stats. & Regs. ¶ 31,196 (2005).

[15] While Southwest Power Pool, Inc. (SPP) and the California Independent System Operator Corporation (Cal ISO), respectively are a Commission-approved RTO and ISO, they do not satisfy the requirements of section 210(m)(1)(A) because neither has day-ahead markets. However, any utility within SPP and Cal ISO may file an application with the Commission to seek relief from the mandatory purchase obligation under sections 210(m)(1)(B) or (C), on a case-by-case basis.

[16] *See Midwest Independent Transmission System Operator, Inc.*, 97 FERC ¶ 61,326 (2001) *order on reh'g*, 103 FERC ¶ 61,169 (2003).

[17] *See Midwest Independent Transmission System Operator, Inc.*, 108 FERC ¶ 61,163 (Midwest ISO, FERC Electric Tariff, Third Revised Volume No. 1, Module C), *order on reh'g*, 109 FERC ¶ 61,157 (2004), *order on reh'g*, 111 FERC ¶ 61,043 (2005).

[18] *PJM Interconnection, L.L.C.*, 96 FERC ¶ 61,061 (2001). On December 20, 2002, in *PJM Interconnection, L.L.C.*, 101 FERC ¶ 61,345 (2002), PJM was granted full, rather than provisional, RTO status. Independence was one of the matters considered in the 2002 Order.

[19] PJM Interconnection, L.L.C., FERC Electric Tariff, Sixth Revised Volume No. 1.

energy. Accordingly, we would expect that such long-term sales would be available to all participants in PJM's footprint. Therefore, we propose to find that PJM meets the conditions of subparagraph (A).

(3) ISO–NE

25. ISO–NE received Commission approval as an independent regional transmission operator on March 24, 2004, by having satisfied the Commission's criterion of independence from market participants.[20] Due to ISO–NE's status as an RTO, we believe that the ISO–NE satisfies the "independently administered" condition of subparagraph (A)(i). With respect to the second condition of subparagraph (A)(i), ISO–NE, pursuant to Market Rule 1 of its OATT, commenced operation of its auction-based energy markets on March 1, 2003. Since ISO–NE's market participants have access to auction-based day ahead and real time wholesale energy markets, a QF would have the same opportunity. Also, there are bilateral contracts in ISO–NE for the long-term sales of capacity and energy. Accordingly, we would expect that such long-term sales would be available to all participants in ISO–NE's footprint. Therefore we propose to find that ISO–NE meets the conditions of subparagraph (A).

(4) NYISO

26. The NYISO received Commission authorization to operate as an independent transmission operator on June 30, 1998 after showing that it is independent of market participants.[21] On November 18, 1999, the NYISO commenced operation of its auction-based energy markets. Under the ISO Market Administration and Control Area Services Tariff, NYISO's market participants have access to auction-based day ahead and real time wholesale energy markets,[22] and a QF would have the same opportunity as other generators within NYISO to sell energy into NYISO's auction-based day ahead and real time wholesale energy markets. Also, there are bilateral contracts in NYISO for the long-term sales of capacity and energy. Accordingly, we would expect that such long-term sales would be available to all participants in NYISO's footprint. Therefore we propose to find that NYISO meets the conditions of subparagraph (A).

(5) Conclusion

27. The Commission thus proposes to find in this rulemaking proceeding that QFs interconnected with electric utilities that are members of Midwest ISO, PJM, ISO–NE, and NYISO have nondiscriminatory access to those markets and those markets meet the section 210(m)(1)(A) criteria for removing the obligation of those electric utilities to enter into new contracts or obligations with the QFs. We seek comments, including specific evidence, which either support or refute this preliminary finding Finally, as noted previously, we seek comment on whether the obligation to purchase should be retained in these markets for "small" QFs.

28. Under our proposed regulations, to claim relief from the purchase obligation, electric utilities that are members of Midwest ISO, PJM, ISO–NE, and NYISO will need to make compliance filings pursuant to section 210(m)(3). This compliance filing is discussed in more detail in our discussion of section 210(m)(3).

(b) Subparagraphs B and C

29. The Commission proposes to determine on a case-by-case basis [23] whether a utility has met the requirements of sections 210(m)(1)(B) and 210(m)(1)(C) for relief from its purchase obligation. An electric utility filing an application claiming to meet the requirements of section 210(m)(1)(B) or section 210(m)(1)(C) of PURPA must demonstrate the "factual basis upon which relief is requested." Applicants should provide, among other evidence, actual sales data for (1) long-term and short-term capacity and (2) long-term, short-term, and real-time electric energy as well as evidence that the utility operates in a competitive wholesale market. Accordingly, to be relieved of their mandatory purchase obligations, electric utilities that are not members of Midwest ISO, PJM, ISO–NE, and NYISO would be required to file such applications with the Commission pursuant to section 210(m)(3) of PURPA.

30. We propose that other markets, *i.e.*, both non-auction-based markets and non-RTO markets, as well as new auction-based markets, and utility-specific markets would be addressed on a case-by-case basis, pursuant to section 210(m)(3) discussed below. In addition, subsequent changes to market conditions in all markets would be handled on a case-by-case basis, pursuant to section 210(m)(4) discussed below.

3. Other Issues

31. Section 210(m)(1) states that no electric utility shall be obligated to purchase from a QF if the Commission finds that the QF has *nondiscriminatory access* to the market conditions identified in each subparagraph. We propose that there be a rebuttable presumption that a utility provides *nondiscriminatory access* if it has an open access transmission tariff in compliance with our *pro forma* OATT (or a Commission-approved reciprocity tariff).[24] We also propose that QFs or any other affected party should be allowed to rebut that presumption, for example, by providing specific and credible evidence that the QF does not have non-discriminatory access to wholesale markets. However, the presumption cannot be rebutted by an argument that the utility has not properly implemented or administered its OATT. Improper implementation of an OATT is more properly the subject of a complaint and the Commission will take appropriate steps in response to a complaint to ensure that the OATT is properly implemented.

32. Section 210(m)(1) also states that no electric utility "shall be required to enter into a new contract or obligation" to purchase electric energy from a QF if the Commission makes the required finding. The Commission proposes to find that when a contract terminates by its own accord, an electric utility is not compelled to enter into a new, successor contract with the QF if the Commission has found that the QF has nondiscriminatory access to markets that satisfy the criteria of section 210(m)(1). Some have alleged that the grant of QF status means that electric utilities have an "obligation" to purchase from that QF in perpetuity. We disagree. That a facility has QF status does not mean that an electric utility has an "obligation" to purchase from the QF in perpetuity, or, conversely, that the QF has the right to demand that the utility purchase at avoided-cost rates in perpetuity. The Commission proposes to find that if a contract is entered into after August 8, 2005, the date of enactment, but before the

[20] *ISO New England, Inc.*, 106 FERC 61,280 (2004).

[21] *Central Hudson Gas & Electric Co.*, 83 FERC ¶ 61,352 (1998), *order on reh'g*, 87 FERC ¶ 61,135 (1999).

[22] New York Independent System Operator, Inc., FERC Electric Tariff Original Volume No. 2.

[23] We will allow joint applications to be filed by a number of utilities in a region if the applications for relief from the purchase obligation present common issues of law and fact. We would expect common issues of law and fact to exist where one or more utilities operate within the same market.

[24] In Docket No. RM05–25–000, the Commission is currently reviewing the adequacy and sufficiency of the pro forma OATT to ensure that it prevents undue discrimination in the provision of transmission service.

Commission has determined that an electric utility is entitled to relief from the obligation to purchase from a QF, the contract already entered into will be treated as though it was in effect on August 8, 2005 for purposes of section 210(m)(1).

B. Purchase and Sale Obligations for New Cogeneration Facilities

33. Section 210(m)(2)(A) of PURPA reads:

REVISED PURCHASE AND SALE OBLIGATIONS FOR NEW FACILITIES—(A) After the date of enactment of this subsection, no electric utility shall be required pursuant to this section to enter into a new contract or obligation to purchase from or sell electric energy to a facility that is not an existing qualifying cogeneration facility unless the facility meets the criteria for qualifying cogeneration facilities established by the Commission pursuant to the rulemaking required by subsection (n).

34. This provision reinforces the requirement that new qualifying cogeneration facilities must satisfy the section 210(n) criteria for new qualifying cogeneration facilities, which the Commission is implementing in pending Docket No. RM05–36–000. The Commission proposes to make this clarification in section 292.309(d) of its regulations.

35. Section 210(m)(2)(B) defines the term "existing qualifying cogeneration facility" to mean a facility that: (i) Was a qualifying cogeneration facility on the date of enactment of subsection (m), or (ii) had filed with the Commission a notice of self-certification, self-recertification or an application for Commission certification under 18 CFR 292.207 prior to the date on which the Commission issues the final rule required by subsection 210(n). The Commission proposes to adopt this definition in new section 292.309(b)(1) of its regulations.

C. Application for Relief

36. Section 210(m)(3) of PURPA states:

COMMISSION REVIEW—Any electric utility may file an application with the Commission for relief from the mandatory purchase obligation pursuant to this subsection on a service territory-wide basis. Such application shall set forth the factual basis upon which relief is requested and describe why the conditions set forth in subparagraphs (A), (B) or (C) of paragraph (1) of this subsection have been met. After notice, including sufficient notice to potentially affected qualifying cogeneration facilities and qualifying small power production facilities, and an opportunity for comment, the Commission shall make a final determination within 90 days of such application regarding whether the conditions set forth in subparagraphs (A), (B) or (C) of paragraph (1) have been met.

37. The Commission proposes to include in new section 292.310 the language of section 210(m)(3) of PURPA. Since the enactment of EPAct 2005, two applications for relief from the mandatory purchase obligation have been filed with the Commission.[25] In *Alliant*, the Commission explained that, in order to meet the express statutory requirement of "notice," including "sufficient notice to potentially affected qualifying cogeneration facilities and qualifying small power production facilities," contained in section 210(m)(3) of PURPA, it would require that an applicant identify all potentially affected QFs in any application for relief filed pursuant to section 210(m)(3).[26] The Commission then described which facilities constitute "all potentially affected QFs." [27]

38. Consistent with *Alliant* and *Montana-Dakota*, before the Commission will consider an application filed pursuant to section 210(m)(3) of PURPA, an applicant must first identify in the application all potentially affected QFs (with their names and current addresses)—including: (1) Those QFs that have existing power purchase contracts with the applicant; (2) other QFs that sell their output to the applicant or that have pending requests for the applicant to purchase their output; (3) any developer of generating facilities with whom the applicant has agreed to enter into power purchase contracts or is discussing power purchase contacts; (4) the developers of facilities that have pending state avoided cost proceedings; and (5) any other QFs that the applicant reasonably believes to be affected by its petition. This will ensure that the statutory obligation is met to provide notice and an opportunity to comment to all potentially affected QFs. The Commission proposes to incorporate this interpretation of "sufficient notice" and "all potentially affected QFs" in new section 292.310(b) and (c).

39. We point out that under section 210(m)(3) the Commission must make a *finding* regarding an application for relief of the purchase obligation and that the finding must be made within 90 days of the date of such application. The Commission, accordingly, will expect an application for relief to be fully supported by documentation upon which the required finding can be made, *i.e.*, a case in chief. For those not in one of the Commission-certified markets, such documentation should include, but is not limited to: (1) Prepared testimony; (2) affidavits; (3) exhibits; and (4) any other evidence. Given the statutory 90-day time limit for finding, we stress that the burden will be on the applicant to provide a fully-supported application in the first instance.

40. With regard to applications filed by electric utilities that are members of Midwest ISO, PJM, NYISO, or ISO–NE, an electric utility need only submit a compliance filing showing that: (1) It is a member of one of these RTOs/ISOs; (2) the Commission has made a final finding that the RTO/ISO that it is a member of provides QFs with nondiscriminatory access;[28] (3) a list of all potentially affected QFs; and (4) the QFs have the right to request service under an OATT or OATTs (or reciprocity tariffs) on file. Once a final rule issues and the Commission has acted on rehearing of the final rule, the Commission will not reevaluate its decision on specific markets made in the instant proceeding, absent changed circumstances. The Commission seeks comments on whether there are any QFs within the service territories of members of the Midwest ISO, PJM, ISO–NE, and NYISO that, although they have access to an OATT or OATTs (or reciprocal tariffs), nonetheless do not have nondiscriminatory access to those markets.

41. We anticipate that the compliance filings of the electric utilities that are members of the Midwest ISO, PJM, NYISO, or ISO–NE and seeking relief from the purchase obligation will be essentially ministerial; we do not expect the findings made in this rulemaking to be re-litigated in the compliance filing proceeding. In this regard, we conclude that the existence of a filed OATT (or reciprocity tariff) will be construed to provide nondiscriminatory access. If a QF believes that the administration or implementation of the OATT denies it access to markets, it is not an issue for the compliance filing proceeding; instead the QF may file a complaint challenging the implementation or administration of an OATT.

[25] *See Alliant Energy Corporate Services, Inc.*, 113 FERC ¶ 61,024 (2005) (*Alliant*); *Montana-Dakota Utilities Co.*, 113 FERC ¶ 61,045 (2005) (*Montana-Dakota*). In both instances, the Commission dismissed petitions for declaratory orders pursuant to section 210(m)(3) of PURPA requesting relief from the mandatory purchase obligation on the grounds of insufficient notice.

[26] *Alliant*, 113 FERC ¶ 61,024 at P 18.

[27] *Id.* at P 19–20.

[28] The final rule in this proceeding must have become effective before an electric utility may rely upon it. As a result, any electric utilities that file early and seek to rely on the preliminary findings with respect to Midwest ISO, PJM, NYISO or ISO–NE in this NOPR will not be permitted to do so.

D. Reinstatement of Obligation To Purchase

42. Section 210(m)(4) provides:

REINSTATEMENT OF OBLIGATION TO PURCHASE. At any time after the Commission makes a finding under paragraph (3) relieving an electric utility of its obligation to purchase electric energy, a qualifying cogeneration facility, a qualifying small power production facility, a State agency, or any other affected person may apply to the Commission for an order reinstating the electric utility's obligation to purchase electric energy under this section. Such application shall set forth the factual basis upon which the application is based and describe why the conditions set forth in subparagraphs (A), (B) or (C) of paragraph (1) of this subsection are no longer met. After notice, including sufficient notice to potentially affected utilities, and opportunity for comment, the Commission shall issue an order within 90 days of such application reinstating the electric utility's obligation to purchase electric energy under this section if the Commission finds that the conditions set forth in subparagraphs (A), (B) or (C) of paragraph (1) which relieved the obligation to purchase, are no longer met.

43. The Commission views this section as an opportunity for a QF, a state agency, or any affected person to seek to reinstate the purchase obligation should there be a material change in the circumstances under which the Commission granted relief. We note that the applicant bears the burden to "set forth the factual basis" upon which the application is based. The requirement for a "factual basis" indicates that allegations of a change in the conditions upon which relief was granted must be supported with evidence. The Commission proposes to consider these applications on a case-by-case basis.

44. Consistent with our interpretation of "notice" under section 210(m)(3), the Commission will require an applicant to identify all potentially affected utilities in the application so that the Commission will be able to meet its statutory requirement to provide sufficient notice and an opportunity for comment.

E. Obligation To Sell

45. Section 292.303(b) of the Commission's regulations, 18 CFR 292.303(b), states that: "Each electric utility shall sell to any qualifying facility, in accordance with § 292.305, any energy and capacity requested by the qualifying facility." Under new section 210(m)(5), this mandatory obligation to sell can be terminated if the Commission finds that: "Competing retail electric suppliers are willing and able to sell and deliver electric energy to the qualifying cogeneration facility or qualifying small power production facility; and the electric utility is not required by State law to sell electric energy in its service territory."

46. The Commission proposes to incorporate the language of section 210(m)(5) of PURPA in new section 292.312 of the Commission's regulations. The Commission proposes to interpret the phrase "new contract or obligation" contained in section 210(m)(3) consistently with its interpretation of the same words contained in section 210(m)(1) of PURPA.[29]

47. The Commission is also proposing to include a provision, section 292.313, allowing a QF, State agency, or any other affected person to apply to the Commission for an order reinstating the electric utility's obligation to sell electric energy if the factual predicate for the determination that the obligation to purchase should be terminated no longer exists.

F. Section 210(m)(6)

48. Section 210(m)(6) of PURPA requires that:

Nothing in this subsection affects the rights or remedies of any party under any contract or obligation, in effect *or* pending approval before the appropriate State regulatory authority or non-regulated electric utility on the date of enactment of this subsection, to purchase electric energy or capacity from or to sell electric energy or capacity to a qualifying cogeneration facility or qualifying small power production facility under this Act (including the right to recover costs of purchasing electric energy or capacity).

49. We propose to implement section 210(m)(6) of PURPA by adopting the language of the statute in section 292.314. In addition, the Commission will clarify that the stage of the construction of a facility has no bearing on whether the protections of section 210(m)(6) are triggered. The Commission interprets section 210(m)(6) to protect the rights and remedies under a contract or obligation in effect *or* pending approval before the state regulatory authority, regardless of the construction stage of the facility that may be the subject of the contract or obligation. We solicit comments on whether further or different language and/or clarifications other than those proposed here should be incorporated into our regulations.

G. Section 210(m)(7)

50. Section 210(m)(7) of PURPA requires that:

(A) The Commission shall issue and enforce such regulations as are necessary to ensure that an electric utility that purchases electric energy or capacity from a qualifying cogeneration facility or qualifying small power production facility in accordance with any legally enforceable obligation entered into or imposed under this section recovers all prudently incurred costs associated with the purchase. (B) A regulation under subparagraph (A) shall be enforceable in accordance with the provisions of law applicable to enforcement of regulations under the Federal Power Act (16 U.S.C. 791a *et seq.*).

51. The Commission does not believe that regulations are necessary at this time; this is a matter that the Commission can address on a case-by-case basis. However, the Commission will consider a regulation under this section in the future if a need becomes apparent.

52. We solicit comments on whether there is a need for the Commission to consider a regulation, and if so what that regulation should state, to ensure that an electric utility that purchases electric energy or capacity from a cogeneration QF or qualifying small power production facility in accordance with any legally enforceable obligation entered into or imposed under section 210(m)(7) recovers all prudently incurred costs associated with the purchase.

IV. Information Collection Statement

53. The Commission is submitting the following collection of information contained in this proposed rulemaking to the Office of Management and Budget (OMB) for review under section 3507(d) of the Paperwork Reduction Act of 1995.[30] The Commission identifies the information provided for under part 292 as FERC–556. These collections of information are specifically mandated by statute.

54. The Commission solicits comments on the Commission's need for this information, whether the information will have practical utility, the accuracy of the provided burden estimates, ways to enhance the quality and clarity of the information that the Commission will collect, and any suggested methods for minimizing the respondent's burden, including the use of information techniques. The burden estimates for complying with this proposed rule are as follows:

[29] *See* P 29 *supra*.

[30] 44 U.S.C. 3507(d) (2000).

Data collection FERC–556	Number of respondents	Number of responses	Hour per response	Total annual hours
§ 292.310	230	1	2	460
§ 292.312	230	1	2	460
§ 292.413	630	1	3	1,890
Totals	860	1		2,810

Total Annual Hours for the Collection: (reporting + recordkeeping if appropriate)

Information Collection Costs: Because of the regional differences and the various staffing levels that will be involved in preparing the documentation (legal, technical and support) the Commission is using an hourly rate of $150 to estimate the costs for filing and other administrative processes (reviewing instructions, searching data sources, completing and transmitting the collection of information). The estimated cost is anticipated to be $421,500.

Title: FERC–556 Small Power Production and Cogeneration Facilities.

Action: Proposed Data Collections.

OMB Control Nos.: 1902–0075.

Upon approval of a collection of information, OMB will assign an OMB control number and an expiration date. Respondents subject to the filing requirements of this rule will not be penalized for failing to respond to these collections of information unless the collections of information display a valid OMB control number or the Commission has provided justification as to why the control number should not be displayed.

Respondents: Businesses or other for profit, state, local or tribal government.

Necessity of the Information: The Commission proposes amending its regulations to implement section 210(m) of PURPA which was enacted in section 1253 of the EPAct 2005; specifically, its regulations governing purchases of electric energy from and sales of electric energy to qualifying small power production and cogeneration facilities

These requirements conform to the Commission's plan for efficient information collection, communication, and management within the energy industry. The Commission has assured itself, by means of internal review, that there is specific, objective support for the burden estimates associated with the information requirements.

Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street, NE., Washington, DC 20426 [Attention: Michael Miller, Office of the Executive Director, Phone: (202) 502–8415, fax: (202) 273–0873, e-mail: *michael.miller@ferc.gov*].

55. For submitting comments concerning the collection(s) of information and the associated burden estimate(s), please send your comments to the contact listed above and to the Office of Management and Budget, Office of Information and Regulatory Affairs, Washington, DC 20503, [Attention: Desk Officer for the Federal Energy Regulatory Commission, phone: (202) 395–4650, fax: (202) 395–7285, e-mail: *oira_submission@omb.eop.gov*.

V. Environmental Analysis

56. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment. The Commission has categorically excluded certain actions from this requirement as not having a significant effect on the human environment. As explained above, this proposed rule is clarifying in nature. It interprets several amendments made to PURPA by EPAct 2005, and clarifies the applicability of these amendments to electric utilities and QFs; it does not substantially change the effect of the legislation. Accordingly, no environmental consideration is necessary.

VI. Regulatory Flexibility Act Analysis

57. The Regulatory Flexibility Act of 1980 (RFA) [31] generally requires a description and analysis of rules that will have significant economic impact on a substantial number of small entities and where notice and comment rulemaking is required. Certain rules are exempt from notice and comment from the RFA requirements; exempt rules include interpretative rules, general statements of policy, or rules of agency organization procedure or practice.[32] Interpretative rules "generally interpret the intent expressed by Congress, where an agency does not insert its own judgments or interpretations in implementing a rule and simply regurgitates statutory language." [33] The rule we are proposing in this docket is an interpretative rule. Accordingly, no regulatory flexibility analysis is required.

VII. Comment Procedures

58. The Commission invites interested persons to submit comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Comments are due February 27, 2006. Reply comments are due March 28, 2006. Comments and reply comments must refer to Docket No. RM06–10–000, and must include the commenters' names, the organizations they represent, if applicable, and their address in their comments. Comments and reply comments may be filed either in electronic or paper format.

59. Comments and reply comments may be filed electronically via the eFiling link on the Commission's Web site at *http://www.ferc.gov*. The Commission accepts most standard word processing formats and commenters may attach additional files with supporting information in certain other file formats. Commenters filing electronically do not need to make paper filings. Commenters that are not able to file comments and reply comments electronically must send an original and 14 copies of their comments to: Federal Energy Regulatory Commission, Office of the Secretary, 888 First Street, NE., Washington, DC 20426.

60. All comments and reply comments will be placed in the Commission's public files and may be viewed, printed, or downloaded remotely as described in the Document Availability section below. Commenters on this proposal are not required to serve copies of their comments and reply comments on other commenters.

VIII. Document Availability

61. In addition to publishing the full text of this document in the **Federal Register**, the Commission provides all

[31] 5 U.S.C. 601–12.

[32] 5 U.S.C. 553(b)(A).

[33] "How to Comply with the Regulatory Flexibility Act: A Guide for Government Agencies", Small Business Administration, Office of Advocacy, P.5, May 2003.

interested persons an opportunity to view and/or print the contents of this document via the Internet through the Commission's Home Page (*http://www.ferc.gov*) and in the Commission's Public Reference Room during normal business hours (8:30 a.m. to 5 p.m. Eastern time) at 888 First Street, NE., Room 2A, Washington, DC 20426.

62. From the Commission's Home Page on the Internet, this information is available in the Commission's document management system, eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

63. User assistance is available for eLibrary and the Commission's Web site during normal business hours. For assistance, please contact FERC Online Support at 1–866–208–3676 (toll free) or (202) 502–8222 (e-mail at *FERCOnlineSupport@FERC.gov*), or the Public Reference Room at (202) 502–8371, TTY (202) 502–8659 (e-mail at *public.referenceroom@ferc.gov*).

List of Subjects in 18 CFR Part 292

Electricity, Electric power plants, Electric utilities, Natural gas, Reporting and recordkeeping requirements.

By direction of the Commission.

Magalie R. Salas,

Secretary.

In consideration of the foregoing, the Commission proposes to amend part 292, Chapter I, Title 18, *Code of Federal Regulations*, as follows:

PART 292—REGULATIONS UNDER SECTIONS 201 AND 210 OF THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978 WITH REGARD TO SMALL POWER PRODUCTION AND COGENERATION

1. The authority citation for part 292 continues to read as follows:

Authority: 16 U.S.C. 791a–825r, 2601–2645; 31 U.S.C. 9701; 42 U.S.C. 7101–7352.

2. Section 292.303 is amended by revising paragraphs (a) and (b) to read as follows:

§ 292.303 Electric utility obligations under this subpart.

(a) *Obligation to purchase from qualifying facilities.* Each electric utility shall purchase, in accordance with § 292.304, unless exempted by § 292.309, any energy and capacity which is generated from a qualifying facility

(1) Directly to the electric utility; or

(2) Indirectly to the electric utility in accordance with paragraph (d) of this section.

(b) *Obligation to sell to qualifying facilities.* Each electric utility shall sell to any qualifying facility, in accordance with § 292.305, unless exempted by § 292.312 of this chapter, energy and capacity requested by the qualifying facility.

* * * * *

3. Sections 292.309 through 292.314 are added to read as follows:

§ 292.309 Termination of obligation to purchase from qualifying facilities.

(a) An electric utility shall no longer be required to enter into a new contract or obligation to purchase electric energy from a qualifying cogeneration facility or a qualifying small power production facility if the Commission finds that the qualifying cogeneration facility or qualifying small power production facility has nondiscriminatory access to:

(1)(i) Independently administered, auction-based day ahead and real time wholesale markets for the sale of electric energy; and

(ii) Wholesale markets for long-term sales of capacity and electric energy; or

(2)(i) Transmission and interconnection services that are provided by a Commission-approved regional transmission entity and administered pursuant to an open access transmission tariff that affords nondiscriminatory treatment to all customers; and

(ii) Competitive wholesale markets that provide a meaningful opportunity to sell capacity, including long-term and short-term sales, and electric energy, including long-term, short-term and real-time sales, to buyers other than the utility to which the qualifying facility is interconnected; in determining whether a meaningful opportunity to sell exists within the meaning of § 292.309(a)(2)(ii), the Commission shall consider, among other factors, evidence of transactions within the relevant market; or

(3) Wholesale markets for the sale of capacity and electric energy that are, at a minimum, of comparable competitive quality as markets described in paragraphs (a)(1) and (a)(2) of this section.

(b) *Definitions.* (1) For purposes of this section, an "existing qualifying cogeneration facility" is a facility that:

(i) Was a qualifying cogeneration facility before or on August 8, 2005; or

(ii) Had filed with the Commission a notice of self-certification, self-recertification or an application for Commission certification under § 292.207 prior to [the date the Commission issues a final rule].

(2) For the purposes of this section, a "new qualifying cogeneration facility" is a facility that satisfies the criteria for qualifying cogeneration facilities under § 292.205.

(3) For the purposes of this section, a renewal of a contract that expires by its own terms is a "new contract or obligation."

(c) For the purposes of this section, there is a rebuttable presumption that there is "non-discriminatory access" to wholesale markets when a qualifying facility is provided transmission services pursuant to a Commission-approved open access transmission tariff or reciprocity tariff, and interconnection services pursuant to Commission-approved interconnection rules.

(d) No electric utility shall be required to enter into a new contract or obligation to purchase from or sell electric energy to a facility that is not an existing qualifying cogeneration facility unless the facility meets the criteria for new qualifying cogeneration facilities established by the Commission in § 292.205.

§ 292.310 Procedures for utilities requesting termination of obligation to purchase from qualifying facilities.

(a) Any electric utility may file an application with the Commission for relief from the mandatory purchase obligation in § 292.303(a) pursuant to this section on a service territory-wide basis. Such application shall set forth the factual basis upon which relief is requested and describe why the conditions set forth in § 292.309(a)(1), (2) or (3) have been met. After notice, including sufficient notice to potentially affected qualifying cogeneration facilities and qualifying small power production facilities, and an opportunity for comment, the Commission shall make a final determination within 90 days of such application regarding whether the conditions set forth in § 292.309(a)(1), (2) or (3) have been met; provided, however, that if the Commission has made a determination pursuant to notice and comment rulemaking or order that a particular market meets the criteria for relief in § 292.309(a)(1), (2) or (3), an applicant may make a ministerial application under this section and the application will be treated as a compliance filing.

(b) Sufficient notice shall mean that an electric utility must identify with names and addresses all potentially affected qualifying facilities in an

application filed pursuant to paragraph (a) of this section.

(c) All potentially affected qualifying facilities shall include:

(1) Those qualifying facilities that have existing power purchase contracts with the applicant;

(2) Other qualifying facilities that sell their output to the applicant or that have pending self-certification or Commission certification with the Commission for qualifying facility status whereby the applicant will be the purchaser of the qualifying facility's output;

(3) Any developer of generating facilities with whom the applicant has agreed to enter into power purchase contracts or are in discussion with regard to power purchase contacts;

(4) The developers of facilities that have pending state avoided cost proceedings; and

(5) Any other qualifying facilities that the applicant reasonably believes to be affected by its application filed pursuant to paragraph (a) of this section.

§ 292.311 Reinstatement of obligation to purchase.

At any time after the Commission makes a finding under § 292.310 relieving an electric utility of its obligation to purchase electric energy, a qualifying cogeneration facility, a qualifying small power production facility, a State agency, or any other affected person may apply to the Commission for an order reinstating the electric utility's obligation to purchase electric energy under this section, if there has been a change in the conditions upon which the Commission based its finding. Such application shall set forth the factual basis upon which the application is based and describe why the conditions set forth in § 292.309 (a)(1), (2) or (3) are no longer met. After notice, including sufficient notice to potentially affected utilities, and opportunity for comment, the Commission shall issue an order within 90 days of such application reinstating the electric utility's obligation to purchase electric energy under this section if the Commission finds that the conditions set forth in § 292.309 (a)(1), (2), or (3) which relieved the obligation to purchase, are no longer met.

§ 292.312 Procedures for utilities requesting termination of obligation to sell to qualifying facilities.

(a) An electric utility shall not be required to enter into a new contract or obligation to sell electric energy to a qualifying small power production facility, an existing qualifying cogeneration qualifying facility, or a new qualifying cogeneration facility if the Commission has found that:

(1) Competing retail electric suppliers are willing and able to sell and deliver electric energy to the qualifying cogeneration facility or qualifying small power production facility; and

(2) The electric utility is not required by State law to sell electric energy in its service territory.

(b) Any electric utility may file an application with this Commission for relief from the mandatory obligation to sell under this paragraph on a service territory-wide basis or a single qualifying facility basis. Such application shall set forth the factual basis upon which relief is requested and describe why the conditions set forth in paragraphs (a)(1) and (a)(2) of this section have been met. After notice, including sufficient notice to potentially affected qualifying facilities, and an opportunity for comment, the Commission shall make a final determination within 90 days of such application regarding whether the conditions set forth in paragraphs (a)(1) and (a)(2) of this section have been met.

§ 292.313 Reinstatement of obligation to sell.

At any time after the Commission makes a finding under § 292.312 relieving an electric utility of its obligation to sell electric energy, a qualifying cogeneration facility, a qualifying small power production facility, a State agency, or any other affected person may apply to the Commission for an order reinstating the electric utility's obligation to sell electric energy under this section, if there has been a change in the conditions upon which the Commission based its finding. Such application shall set forth the factual basis upon which the application is based and describe why the conditions set forth in § 292.312 (a)(1) and (a)(2) are no longer met. After notice, including sufficient notice to potentially affected utilities, and opportunity for comment, the Commission shall issue an order within 90 days of such application reinstating the electric utility's obligation to sell electric energy under this section if the Commission finds that the conditions set forth in § 292.312 (a)(1) and (a)(2) are no longer met.

§ 292.314 Existing rights and remedies.

Nothing in this §§ 292.303 through 292.314 affects the rights or remedies of any party under any contract or obligation, in effect or pending approval before the appropriate State regulatory authority or non-regulated electric utility on or before August 8, 2005, to purchase electric energy or capacity from or to sell electric energy or capacity to a qualifying cogeneration facility or qualifying small power production facility (including the right to recover costs of purchasing electric energy or capacity).

[FR Doc. E6–940 Filed 1–26–06; 8:45 am]

BILLING CODE 6717–01–P

NATIONAL ARCHIVES AND RECORDS ADMINISTRATION

Information Security Oversight Office

32 CFR Part 2004

RIN 3095–AB34

Information Security Oversight Office; National Industrial Security Program Directive No. 1

AGENCY: Information Security Oversight Office (ISOO), National Archives and Records Administration (NARA).

ACTION: Implementing directive; proposed rule.

SUMMARY: The Information Security Oversight Office (ISOO), National Archives and Records Administration (NARA), is publishing this Directive as a proposed rule and pursuant to section 102(b)(1) of Executive Order 12829, as amended, relating to the National Industrial Security Program. This order establishes a National Industrial Security Program (NISP) to safeguard Federal Government classified information that is released to contractors, licensees, and grantees of the United States Government. Redundant, overlapping, or unnecessary requirements impede those interests. Therefore, the NISP serves as the single, integrated, cohesive industrial security program to protect classified information and to preserve our Nation's economic and technological interests. This Directive sets forth guidance to agencies to set uniform standards throughout the NISP that promote these objectives.

DATES: Comments must be received on or before March 13, 2006.

ADDRESSES: You may submit comments, identified by "RIN 3095–AB34," by any of the following methods:

Federal eRulemaking Portal: *http://www.regulations.gov.* Follow the instructions for submitting comments.

E-mail: *comments@nara.gov.* Include "RIN 3095–AB34" in the subject line of the message.

Fax: (301) 837–0319.

Mail: Regulation Comments Desk (NPOL), Room 4100, National Archives

1 **CERTIFICATE OF SERVICE**

2

3 I certify that on July 12, 2006, I served the foregoing upon all parties of record in this

4 proceeding by delivering a copy by electronic mail and by mailing a copy by postage prepaid

5 first class mail or by hand delivery/shuttle mail to the parties accepting paper service.

6 **UM 1129 PHASE II**

7 PORTLAND GENERAL ELECTRIC CO. RATES &
REGULATORY AFFAIRS
8 PORTLAND GENERAL ELECTRIC COMPANY
121 SW SALMON ST 1WTC0702
PORTLAND OR 97204
9 pge.opuc.filings@pgn.com

10 **ASCENTERGY CORP**
BRUCE CRAIG
11 440 BENMAR DR STE 2230
HOUSTON TX 77060
12 bcraig@asc-co.com

W
13 **ATER WYNNE LLP**
LISA F RACKNER **- CONFIDENTIAL**
14 ATTORNEY
222 SW COLUMBIA ST STE 1800
PORTLAND OR 97201-6618
15 lfr@aterwynne.com

16 **W**
ATER WYNNE, LLP
17 WENDY L MARTIN
222 SW COLUMBIA ST - STE 1800
PORTLAND OR 97201
18 wlm@aterwynne.com

19 **BEN JOHNSON ASSOCIATES**
DON READING **- CONFIDENTIAL**
20 6070 HILL ROAD
BOISE ID 83703
21 dreading@mindspring.com

CABLE HUSTON BENEDICT ET AL
22 THOMAS M GRIM
ATTORNEY
23 1001 SW FIFTH AVE STE 2000
PORTLAND OR 97204-1136
24 tgrim@chbh.com

CENTRAL OREGON IRRIGATION DISTRICT
25 STEVEN C JOHNSON
DISTRICT MANAGER
26 1055 SW LAKE CT
REDMOND OR 97756
stevej@coid.org

CITIZENS' UTILITY BOARD OF OREGON
LOWREY R BROWN
UTILITY ANALYST
610 SW BROADWAY - STE 308
PORTLAND OR 97205
lowrey@oregoncub.org

CITIZENS' UTILITY BOARD OF OREGON
JASON EISDORFER
ENERGY PROGRAM DIRECTOR
610 SW BROADWAY STE 308
PORTLAND OR 97205
jason@oregoncub.org

COLUMBIA ENERGY PARTNERS
CHRIS CROWLEY
100 E 19TH STE 400
VANCOUVER WA 98663
ccrowley@columbiaep.com

CROSSBORDER ENERGY
R THOMAS BEACH **- CONFIDENTIAL**
2560 NINTH ST - STE 316
BERKELEY CA 94710
tomb@crossborderenergy.com

D R JOHNSON LUMBER COMPANY
RANDY CROCKET
CHIEF FINANCIAL OFFICER
PO BOX 66
RIDDLE OR 97469
randyc@drjlumber.com

DAVISON VAN CLEVE
IRION A SANGER **- CONFIDENTIAL**
ASSOCIATE ATTORNEY
333 SW TAYLOR - STE 400
PORTLAND OR 97204
ias@dvclaw.com

DAVISON VAN CLEVE PC
S BRADLEY VAN CLEVE **- CONFIDENTIAL**
333 SW TAYLOR - STE 400
PORTLAND OR 97204
mail@dvclaw.com

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 378-6322

DEPARTMENT OF JUSTICE
JANET L PREWITT - **CONFIDENTIAL**
ASST AG
1162 COURT ST NE
SALEM OR 97301-4096
janet.prewitt@doj.state.or.us

DOUGLAS COUNTY FOREST PRODUCTS
MICK BARANKO
CONTROLLER
PO BOX 848
WINCHESTER OR 97495
mick@dcfp.com

HURLEY, LYNCH & RE, PC
ELIZABETH DICKSON
747 SW MILLVIEW WAY
BEND OR 97702
eadickson@hlr-law.com

W
IDAHO POWER COMPANY
RANDY ALLPHIN
PO BOX 70
BOISE ID 83707-0070
rallphin@idahopower.com

KARL BOKENKAMP
GENERAL MANAGER-POWER SUPPLY PLANNING
PO BOX 70
BOISE ID 83707-0070
kbokenkamp@idahopower.com

JOHN R GALE
VICE PRESIDENT, REGULATORY AFFAIRS
PO BOX 70
BOISE ID 83707-0070
rgale@idahopower.com

SANDRA D HOLMES
PO BOX 70
BOISE ID 83707-0070
sholmes@idahopower.com

BARTON L KLINE
SENIOR ATTORNEY
PO BOX 70
BOISE ID 83707-0070
bkline@idahopower.com

MONICA B MOEN
ATTORNEY
PO BOX 70
BOISE ID 83707-0070
mmoen@idahopower.com

MICHAEL YOUNGBLOOD
PRICING ANALYST
PO BOX 70
BOISE ID 83707
myoungblood@idahopower.com

J R SIMPLOT COMPANY
DAVID HAWK
PO BOX 27
BOISE ID 83707
david.hawk@simplot.com

KAFOURY & MCDOUGAL
LINDA K WILLIAMS
ATTORNEY AT LAW
10266 SW LANCASTER RD
PORTLAND OR 97219-6305
linda@lindawilliams.net

MIDDLEFORK IRRIGATION DISTRICT
CRAIG DEHART
PO BOX 291
PARKDALE OR 97041
mfidcraig@hoodriverelectric.net

OREGON DEPARTMENT OF ENERGY
CAREL DE WINKEL - **CONFIDENTIAL**
625 MARION STREET NE
SALEM OR 97301
carel.dewinkel@state.or.us

OREGON PUBLIC UTILITY COMMISSION
LISA C SCHWARTZ - **CONFIDENTIAL**
SENIOR ANALYST
PO BOX 2148
SALEM OR 97308-2148
lisa.c.schwartz@state.or.us

OREGON WINDFARMS LLC
GLENN IKEMOTO
PRINCIPAL
672 BLAIR AVENUE
PIEDMONT CA 94611
glenni@pacbell.net

W
PACIFICORP
LAURA BEANE
MANAGER, REGULATORY
825 MULTNOMAH STE 800
PORTLAND OR 97232-2153
laura.beane@pacificorp.com

DATA REQUEST RESPONSE CENTER
825 NE MULTNOMAH - STE 800
PORTLAND OR 97232
datarequest@pacificorp.com

MARK TALLMAN
MANAGING DIRECTOR, TRADING
825 MULTNOMAH STE 800
PORTLAND OR 97232-2153
mark.tallman@pacificorp.com

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 378-6322

PORTLAND GENERAL ELECTRIC COMPANY
J RICHARD GEORGE - **CONFIDENTIAL**
ASST GENERAL COUNSEL
121 SW SALMON ST 1WTC1301
PORTLAND OR 97204
richard.george@pgn.com

RICHARDSON & O'LEARY
PETER J RICHARDSON - **CONFIDENTIAL**
PO BOX 7218
BOISE ID 83707
peter@richardsonandoleary.com

W
STOEL RIVES LLP
JOHN M ERIKSSON - **CONFIDENTIAL**
201 SOUTH MAIN ST
SALT LAKE CITY UT 84111
jmeriksson@stoel.com

KEVIN T FOX
ATTORNEY
900 SW FIFTH AVENUE, SUITE 2600
PORTLAND OR 97204-1268
ktfox@stoel.com

SYMBIOTICS, LLC
BRIAN COLE
DIRECTOR, GOVERNMENT & COMMUNITY RELATIONS
PO BOX 1088
BAKER CITY OR 97814
bc@orbisgroup.org

THOMAS H NELSON & ASSOCIATES
THOMAS H NELSON
825 NE MULTNOMAH STE 925
PORTLAND OR 97232
nelson@thnelson.com

VULCAN POWER COMPANY
MARK ALBERT
MARKETING & REGULATORY AFFAIRS
1183 NW WALL ST STE G
BEND OR 97701
malbert@vulcanpower.com

WESTERN WIND POWER
PAUL R WOODIN
PRESIDENT
282 LARGENT LN
GOLDENDALE WA 98620-3519
pwoodin@gorge.net

WEYERHAEUSER COMPANY
ALAN MEYER - **CONFIDENTIAL**
DIRECTOR OF ENERGY MANAGEMENT
698 12TH ST - STE 220
SALEM OR 97301-4010
alan.meyer@weyerhaeuser.com

SETH HOOPER
ENERGY MANAGER
MAIL STOP CH 1K32
33663 WEYERHAEUSER WAY SOUTH
FEDERAL WAY WA 98003
seth.hooper@weyerhaeuser.com

Neoma A. Lane
Legal Secretary
Department of Justice
Regulated Utility & Business Section

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 378-6322