

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

UM 1610

In the Matter of)
)
PUBLIC UTILITY COMMISSION OF)
OREGON)
)
Staff Investigation Into Qualifying Facility)
Contracting and Pricing.)
)
)
)
_____)

**REPLY TESTIMONY OF
JOHN R. LOWE
ON BEHALF OF THE
RENEWABLE ENERGY COALITION**

August 7, 2015

1 **I. INTRODUCTION**

2 **Q. Please state your name and business address.**

3 **A.** My name is John R. Lowe. I am the executive director of the Renewable Energy
4 Coalition (the “Coalition”). My business address is 12040 SW Tremont Street,
5 Portland, Oregon 97225.

6 **Q. Are you the same John Lowe you previously testified in this proceeding?**

7 **A.** Yes.
8

9 **Q. Please summarize your reply testimony.**

10
11 **A.** My reply testimony responds in opposition to parts of the testimony of Staff,
12 PacifiCorp, Portland General Electric Company (“PGE”), and Idaho Power. The
13 Coalition supports many aspects of the testimony of Staff, the Oregon Department
14 of Energy, the Community Renewable Energy Association, and the individual
15 qualifying facility (“QF”) parties. Except in limited circumstances, my testimony
16 will not address testimony that the Coalition supports

17 **Q. Do you have any overall observations?**

18 **A.** Yes. First, there is a considerable amount of recent testimony in this proceeding
19 focused on issues that the Coalition believes are of secondary importance. These
20 are capacity calculations relevant to the short duration resource deficiency period
21 at the end of a long period of resource sufficiency, and the question of who should
22 own renewable energy certificates during the last five years of a rare 20-year
23 contract option. Regarding the former issue, for example, PacifiCorp is proposing
24 a resource sufficiency period ending in 2027. When this resource sufficiency
25 period is applied to avoided cost prices, a fifteen year QF contract would only

1 include three years of resource deficiency prices. This results in a capacity
2 payment or value applied for only three years out of a 15-year contract term, and
3 has little net present value associated with such capacity component, given it is
4 applied near the end of the contract term.

5 The Coalition believes that issues related to the correct payment of
6 capacity during resource sufficiency periods, especially for existing QFs replacing
7 contracts under which capacity had long been provided and paid for is far more
8 significant. And furthermore that all issues related to whether parties to an
9 avoided cost price filing have a realistic opportunity to challenge the avoided cost
10 rates inputs and assumptions is a critical fundamental component of PURPA's
11 implementation far outweighing the relatively minor focuses outlined above.

12 The second major observation is the incongruence between this
13 proceeding and the Idaho Power (UM 1725) and PacifiCorp (UM 1734). In Phase
14 I, the parties and the Commission expended considerable resources to adopt
15 policies regarding size thresholds and contract terms only to have Idaho Power
16 and PacifiCorp seek to quickly upend those policies. The parties are proceeding
17 as if the Commission's policies adopted in UM 1610 continue to apply, but very
18 different policies could come out of UM 1725 and UM 1734.

19 In just one of many examples, PacifiCorp is proposing that it be allowed to
20 use its computer model to set avoided cost rates in this proceeding. PacifiCorp
21 claims large QFs can expend the considerable resources to hire experts to analyze
22 and challenge the assumptions in the computer models. However, in UM 1734
23 PacifiCorp is proposing to lower the size threshold for wind and solar QFs to 100

1 kilowatts (“kW”). While almost no QFs above 10 MWs can afford the time,
2 money and delay associated with reviewing the PacifiCorp’s computer model, it
3 seems doubtful that many QFs below 10 MWs will have the resources to do so.
4 Its puzzling and disturbing that we are re- setting generic policies when it is
5 uncertain whether those policies will continue to exist or be appropriate when a
6 final order in this case is issued.

7 **APPROPRIATE FORUM FOR DISPUTED AVOIDED COST INPUTS AND**
8 **ASSUMPTIONS**

9
10 **Q. What is the Coalition’s position on this issue?**

11
12 **A.** There should be a forum for QFs, Staff, and other interested parties to address and
13 challenge the inputs and assumptions that the utilities (often unilaterally) choose
14 to include in avoided cost rates. The Coalition believes that a separate proceeding
15 at the time the Commission processes a utility’s integrated resource plan (“IRP”)
16 is preferable; however, a robust proceeding subsequent to the IRP’s
17 acknowledgement is the minimally acceptable outcome. The most important
18 aspect is that QFs, Staff, and other interested parties have a fair opportunity to
19 challenge and obtain Commission resolution of the inputs and assumptions in
20 avoided cost rates. After reviewing the testimony of the other parties, the
21 Coalition strongly recommends that the Commission adopt the recommendation
22 of the Oregon Department of Energy to ensure that avoided cost rate inputs and
23 assumptions are fully addressed and are not inconsistent with the results of an
24 acknowledged IRP.

25 **Q. Do PGE and PacifiCorp agree that parties should be allowed to have a full**
26 **and fair opportunity to challenge avoided cost rate inputs and assumptions?**

1
2 **A.** No. PGE did not make its position clear until response testimony, but PGE
3 believes that parties should not be allowed to challenge any assumption or input
4 that is included in a Commission acknowledged IRP. PGE/700, Morton-
5 MacFarlane/4-6. While PGE believes that there should be a post-IRP proceeding
6 to review avoided cost rates, this should be limited to ensuring that those inputs
7 and assumptions are consistent with the utility's IRP. Id. at Morton-
8 MacFarlane/5-6. PacifiCorp is even more extreme, and argues that QFs should
9 not have any opportunity to challenge and obtain a Commission resolution on
10 inputs and assumptions in either the IRP or a compliance filing. PAC/1200,
11 Drennan/2-11.

12 **Q. How do PGE and PacifiCorp justify their positions?**

13
14 **A.** They have extensive testimony about the comprehensiveness of their IRPs, and
15 how the parties "have ample opportunity to participate in the IRP process in order
16 to provide input and challenge assumptions." PGE/700, Morton-MacFarlane/4;
17 PAC/1200, Drennan/3-6. The utilities point out that many of the inputs and
18 assumptions that are used in avoided cost rates are included in the IRP and parties
19 have an opportunity to comment on them.

20 **Q. Are PGE and PacifiCorp missing the entire point of the Coalition, Staff,**
21 **ODOE, and others' testimony on this point?**

22
23 **A.** Yes. They have spent considerable ink dancing around the key issue regarding
24 avoided cost rate inputs and assumptions: whether Staff and other parties have a
25 fair opportunity to review and challenge the utilities' assumptions. Regardless of
26 the analysis done in an IRP or the ability to submit comments, the utilities make

1 the ultimate decision on what the IRP's assumptions and inputs are. Simply put,
2 the utilities can ignore these comments. In addition, while the parties have an
3 opportunity to conduct discovery, the IRP is not a contested case and no party can
4 truly challenge the evidence used in the IRP.

5 More importantly, Staff, QFs and other interested parties cannot obtain a
6 Commission resolution on any of these inputs and assumptions. The Commission
7 does not "approve" an IRP, but instead provides a lower form of recognition
8 called "acknowledgement" which has less weight. While the Commission also
9 acknowledges the overall IRP and some major aspects, like the short-term action
10 plan, the Commission does not acknowledge most of the key inputs and
11 assumptions used to set avoided cost rates. The Commission would never accept
12 PGE's and PacifiCorp's proposals for setting retail rates, and they also should be
13 rejected for setting avoided cost rates.

14 The utilities want the discretion to make the ultimate decision to set the
15 avoided cost rates however they want. The only true limitation of the utilities'
16 ability to develop low avoided cost rates is that they may be concerned with other
17 non-QF issues in the IRP. For example, a utility may desire to place its
18 investment capital in transmission resources instead of generation resources, and
19 use the IRP to justify this shareholder goal. Conversely, the utility may decide it
20 is time to place investment capital into generation resources. Both of these
21 decisions will have major impacts on avoided cost rates, but may be driven by
22 other non-PURPA related goals.

1 **Q. Are there any aspects of PGE and PacifiCorp's positions that have any**
2 **underlying legitimacy?**

3
4 **A.** Yes. In addition to primarily wanting to control how avoided cost rates are set
5 without allowing QFs to effectively review or challenge them, PGE and
6 PacifiCorp are concerned about the possibility of an input or assumption in their
7 IRP being found incorrect or inaccurate in an avoided cost rate proceeding that
8 occurs immediately after their IRP is acknowledged.

9 I have a similar concern, but for the opposite reason. Even if the
10 Commission adopts Staff's recommendation or my alternative recommendation
11 that IRP acknowledgment does not prevent parties from challenging avoided cost
12 inputs and assumptions, this may not work on a practical basis. The Commission
13 may be extremely reluctant to conclude that an input or assumption included in an
14 IRP was incorrect or inaccurate, if it was critical to the IRP's action plan or even a
15 small part of the overall IRP. This is one reason why the approach of a separate
16 but simultaneous avoided cost rate proceeding at the time of the IRP is preferable
17 to a post-IRP acknowledgement review.

18 **Q. Do PGE and PacifiCorp support the Coalition's use of minimum filing**
19 **requirements?**

20
21 **A.** No. Their opposition appears to be primarily based on that the inputs and
22 assumptions are already included in their IRPs, and that it will not benefit the
23 parties. PGE/700, Morton-MacFarlane/4; PAC/1200, Drennan/22. This justifies
24 why the minimum filing requirements are reasonable. The utilities know where
25 this information is located and it should not be burdensome for them to merely
26 point out where Staff and other parties can find the information. The fact that

1 Staff and the QFs are asking for this information demonstrates that it is not easily
2 accessible in massive IRP filings.

3 **CAPACITY VALUE DURING THE RESOURCE SUFFICIENCY PERIOD**

4

5 **Q. Do the resource sufficiency prices adequately compensate QFs for the**
6 **capacity value they provide to the utilities and ratepayers?**

7 **A.** No. Kevin Higgins and my earlier testimony demonstrate that avoided cost rates
8 during the sufficiency period undercompensate QFs. Mr. Higgins is separately
9 addressing the arguments raised by other parties on this issue. I have few
10 additional observations, some of which are along the same theme as Mr. Higgins.

11 **Q. Will Mr. Higgins' recommendation result in inflated or a bonus to avoided**
12 **cost rates?**

13

14 **A.** No. PacifiCorp witness Mr. Dickman argues that including the costs of coal
15 plant upgrades will artificially inflate sufficiency rates. PacifiCorp/1100,
16 Dickman/16. Staff witness Brittany Andrus argues that this will be an
17 inappropriate adder or bonus. Staff/600, Andrus/19-20. Ms. Andrus appears to
18 agree that if there are real costs that would be incurred by the utilities, then these
19 should be accounted for in avoided cost rates. Id. Ms. Andrus appears to argue,
20 however, that the costs of coal plant upgrades should not be included because
21 inclusion will recognize the potential benefits of renewable QFs rather than
22 include real costs. Id.

23 **Q. Do you agree?**

24

25 **A.** No. The Coalition is recommending is that those costs included in the utilities
26 IRP (or separate avoided cost rate review case) be reflected in the avoided cost
27 rates for QFs. If the utility is not planning to make investments in its existing

1 capacity resources, then there are no costs to include in avoided cost rates.

2 However, if the utility is planning on investments in their capacity resources, then
3 these should be included in avoided cost rates. This is not fundamentally different
4 than how avoided cost rates are set now. If the utility is planning on entering into
5 market purchases or building a new power plant, then those costs are the basis for
6 setting avoided cost rates. It should be no different for other major investments.

7 **Q. Mr. Dickman asserts that the IRP may be inaccurate and the company may**
8 **not actually make the coal plant investments identified in the IRP.**
9 **PacifiCorp/1100, Dickman/14. Is this a concern?**

10
11 **A.** Yes, but no more than any other input or assumption in the IRP. All inputs and
12 assumptions in the IRP may be inaccurate, which is why parties should have an
13 opportunity to challenge them. Coal plant investments that are planned on in the
14 next few years are less likely to be inaccurate than a resource sufficiency period
15 that is more than a decade out.

16 **Q. PacifiCorp argues that “PacifiCorp cannot avoid these compliance costs by**
17 **simply adding an Oregon QF.” PAC/1100, Dickman/13. Do you agree?**

18
19 **A.** No, Mr. Dickman’s position is fundamentally at odds with how avoided cost rates
20 are set. Avoided cost rates are set for PacifiCorp when it plans to acquire new
21 resources. Avoided cost rates for Oregon QFs include capacity during the
22 deficiency period in their avoided cost rates when the company is planning on
23 acquiring a new thermal resource any where on its system, including Utah. The
24 logical result of Mr. Dickman’s argument is that Oregon QFs should only be paid
25 for the costs of generation resources in Oregon or that directly serve Oregon
26 customers, and that Oregon ratepayers should only pay for the costs of generation

1 resource in Oregon or that directly serve Oregon customers. This is not how retail
2 or avoided cost rates are set.

3 Mr. Dickman is also arguing that it needs to make these investments
4 because they are tied to coal plants that will need to continue to operate. Again,
5 this is inconsistent with how avoided cost rates are set. You do not look at
6 whether a 1 megawatt (“MW”) QF will displace : 1) an entire coal plant; 2) the
7 coal plant’s upgrades that will be added in the next few years; or 3) a new gas
8 plant that will be built in around a decade. The small QF is paid its proportionate
9 share of the overall costs of the proxy resources (currently now market purchases
10 in the sufficiency period and a thermal or renewable resource in the deficiency
11 period). If 500 MWs of new baseload hydro QFs were built, then these could
12 completely replace both the capacity additions and the underlying coal plant itself.
13 In other words, but for the purchase of power from QFs, the utility would make
14 these investments in its capacity resources. The Coalition’s recommendation is
15 actually conservative because it only asks that the QF be compensated for only
16 the investments to retain rather than replace these capacity resources.

17 **THE MOST APPROPRIATE METHODOLOGY FOR CALCULATING NON-STANDARD**
18 **AVOIDED COST PRICES**

- 19
- 20 **Q. Staff supports using the utilities’ computer models because they have been**
21 **thoroughly vetted. Staff/600, Andrus/22 Do you agree?**
22
- 23 **A.** No. While I do not participate in PacifiCorp’s power cost cases in which its
24 computer model is used, it appears to me that there are modeling disputes almost
25 every year. PacifiCorp’s model must continue to be vetted each year for setting
26 retail rates. PacifiCorp’s computer model has never been challenged in an actual

1 avoided cost rate proceeding for the purposes of how well it calculates avoided
2 cost rates. In the end, QFs have no real recourse other than filing an expensive
3 and time consuming complaint. This is not a practical or realistic option for
4 nearly all QFs.

5 A quick review of PacifiCorp's current transition adjustment mechanism
6 case (Docket No. UE 296) demonstrates that PacifiCorp's computer model is too
7 controversial and subject to abuse to be used for setting avoided cost rates. In UE
8 296, Staff, the Citizens' Utility Board of Oregon ("CUB"), Noble Energy
9 Solutions ("Noble") and the Industrial Customers of Northwest Utilities
10 ("ICNU") raised numerous concerns with the company's filing, including
11 potentially over twenty disputes over how the computer model forecast future
12 power costs. CUB witnesses Bob Jenks and Nadine Hanhan testified that the
13 Company made at least seven modeling changes, including to recognize:

- 14 • Previously unrecognized costs related to day-ahead and real-time
15 balancing transactions;
- 16 • Thermal plant forced outage events (heat rate and minimum capacity
17 derate);
- 18 • Natural gas unit start-up costs and energy;
- 19 • Hourly regulation reserve requirements;
- 20 • Compliance curtailment of certain Company-owned wind facilities for
21 • Avian protection; and
- 22 • Actual performance of wind PPAs.

23 Docket No. UE 296, CUB/100, Jenks-Hanhan/2. While their testimony is not
24 entirely clear, CUB appears to have raised concerns with most, if not all, of these
25 modeling changes.
26

27 Commission Staff witness Jorge Ordonez testified that there should be
28 three changes to PacifiCorp's computer model, including:

- 1 • Modeling of the transmission transfer capability between PacifiCorp's east
2 and west balancing authority areas (BAAs; BAAs Nexus Modeling);
3 • A certain portion of the Company's Energy Imbalance Market (EIM)
4 benefits estimation (EIM Benefits); and
5 • A modeling change regarding day-ahead and real-time balancing
6 transactions (Day-Ahead and Real-Time Modeling).
7

8 Docket No. UE 296, Staff/100, Ordonez/2.

9 Next, Noble's witness Kevin Higgins appears to have raised two concerns
10 with the inputs, assumptions, or calculation of the computer model, including:

- 11 • How to reflect the value of renewable energy credits; and
12 • Calculating credits for customers that elect long term direct access.
13

14 Docket No. UE 296, Noble/100, Higgins/4.

15 Finally, ICNU witness Bradley Mullins has over forty five pages of
16 testimony with about a dozen different adjustments, some of which are related to
17 computer modeling. Mr. Mullins adjustments include those related to:

- 18 • System Balancing;
19 • Regulation Reserve Correction;
20 • Reliability Reserves Metric;
21 • PSE & APS Reserve Diversity;
22 • Idaho Power Asset Exchange Reserves;
23 • Inter-regional EIM Dispatch Benefits related to Seasonality;
24 • Inter-regional EIM Dispatch Benefits related to New EIM Participants;
25 • Hermiston Prudence;
26 • Hermiston Expiring Transmission;
27 • Modeling Outages;
28 • Wind Profiles related to Avian Protection; and
29 • Wind Profiles related to Rolling Averages.
30

31 UE 296, ICNU/100, Mullins/2-4.

32 I am not an expert in the company's computer model and not qualified to
33 opine on the reasonableness of the concerns raised by Staff and intervenors. Even
34 if some of these issues overlap, it appears that there are about twenty different

1 issues related to modeling assumptions, inputs, and methodologies in only one
2 power cost case identified by five different expert witnesses. This is after more
3 than a decade of using the power cost model to set retail rates and direct access
4 transition adjustment credits. In their budget for intervenor funding, ICNU's
5 witness Brad Mullins' hourly rate is \$150, and ICNU plans to pay him over
6 \$20,000 for his work in the case. There is simply no way even large and
7 sophisticated QFs can spend the time and resources to investigate the
8 reasonableness of the company's avoided cost modeling forecasts.

9 QFs also have an entirely different incentive than ratepayer advocates.
10 While the computer modeling calculations impact ratepayers and QFs, ratepayers
11 are not harmed by the delay in reviewing the model and they have an easy
12 opportunity to obtain Commission resolution of their issues. QFs negotiating
13 their avoided cost rates need to obtain quick price certainty. Any delay in setting
14 the avoided cost rates can destroy the project or cause significant monetary harm.
15 In addition, to obtain Commission resolution of an issue, the QF would need to
16 file a complaint at the Commission, which would spoil the negotiations on all
17 other issues.

18 **Q. Mr. Dickman supports using the computer model approach because it is**
19 **more accurate. Is this consistent with his position in other cases?**

20
21 **A.** No. PacifiCorp has complained that its computer model consistently under
22 forecasts net power costs. In UE 296, Mr. Dickman testifies that: "Since at least
23 2007, the Company's actual NPC required to serve customers have exceeded the
24 forecast included in TAM filings." Docket No. UM 296, Dickman/21. The

1 company now wants to use this model that it believes under forecasts net power
2 costs to set avoided cost rates for large QFs. And this is before the company
3 makes adjustments to inputs, assumptions, and methodologies to lower avoided
4 cost rates when it actually uses the model for any specific large QF.

5 **Q. Mr. Dickman addresses issues related to capacity payments for existing QFs**
6 **that renew their contracts. Do you agree?**

7
8 **A.** No. My and Donald Schoenbeck’s testimony from Phase I addressed this issue.
9 The Coalition strongly supports paying existing QFs capacity when they renew
10 their contracts; however, my understanding is that this issue is not on the issues
11 list and we are not making this recommendation at this time. Instead, the
12 Coalition supports the recommendation of Mr. Higgins on treating of QFs in the
13 IRP process, which provides all QFs the benefits provided by existing QFs that
14 renew their contracts. The Commission should revisit the issue of payment of
15 capacity to existing QFs in a future proceeding.

16 **WHEN IS THERE A LEGALLY ENFORCEABLE OBLIGATION?**

17 **Q. Does PacifiCorp completely misrepresent your testimony on legally**
18 **enforceable obligations?**

19
20 **A.** Yes. PacifiCorp witness Bruce Griswold claims he is responding to my
21 testimony, but his characterization of my testimony is extremely different from
22 anything I sponsored in this proceeding. Mr. Griswold states that I recommend
23 “to allow the QF to create a LEO if not all project information is provided to
24 complete a draft contract”, which will result in the “drafting a half-baked and
25 incomplete contract” PAC/1300, Griswold/6-7. Mr. Griswold does not
26 provide citations to the testimony he is supposedly responding to.

1 **Q. What did you actually testify?**

2

3 **A.** That **both** the QF should be required to follow the Commission approved process
4 in the utility's avoided cost rate schedule. Contrary to Mr. Griswold's
5 interpretation, I specifically recommended that "QFs should not be allowed to
6 simply fill out and sign a draft contract in order to establish a legally enforceable
7 obligation" and "QFs should be **required to provide complete information** so
8 that the utility can prepare a draft contract." Coalition/400, Lowe/27 (emphasis
9 added). A QF should only be allowed to form a legally enforceable obligation "if
10 negotiations reach an impasse **after the QF complies with these initial**
11 **requirements.**" *Id.* (emphasis added).

12 **Q. What do you believe the real disputes are between Mr. Griswold (and the**
13 **other utilities) and yourself?**

14

15 **A.** What happens if the utility imposes unreasonable restrictions, does not accept the
16 reasonable information provided by the QF to meet the initial requirements, fails
17 to comply with the schedule in its avoided cost rate schedule for contract
18 negotiations, or other problems develop. In addition, I recommended that a
19 legally enforceable obligation be formed only after the QF has made a good faith
20 attempt to comply with these requirements and resolve the dispute with the utility.
21 My view is that the QF should have some remedy and guarantee that if the utility
22 acts inconsistently with its own rate schedule by requesting unreasonable
23 information, failing to comply with the timelines, refuses to provide a contract, or
24 imposes other unreasonable restrictions.

1 My recommendation is that after the QF complies with the first key steps
2 of the Commission approved process, attempts to resolve the dispute, and there
3 still remain a dispute, then the QF can seek Commission resolution and maintain
4 access to then current avoided cost rates. If the Commission agrees with the QF
5 that the utility unreasonably delayed, imposed inappropriate conditions, or
6 whatever else led to the complaint, then the QF is left in the same situation as if
7 there was no dispute: maintaining avoided cost rates at the time the dispute was
8 unresolved. Similarly, if the Commission agrees with the utility that its
9 conditions were reasonable, there were no unreasonable delays, or whatever else,
10 then the parties are returned to the point at which negotiations broke down. In
11 other words, the QF must accept the condition or requirement in order to maintain
12 the avoided cost rates, which is what would have happened if the QF had not filed
13 a complaint and had agreed to the condition in the first place.

14 Essentially, the QF should have the opportunity to obtain a Commission
15 resolution on the dispute without losing its right to the then current avoided cost
16 rates. Otherwise, the utilities have a hammer to hold over the head of the QF to
17 require them to agree to unreasonable restrictions or delays. My
18 recommendation simply intends to provide the QF with the same rights and
19 obligations that it would have if the negotiation process happened in the manner
20 in which it is intended. The QF should be able to get clarification or confirmation
21 of its rights from the Commission without losing its access to then current
22 avoided cost rates.

23 **HOW SHOULD THIRD-PARTY TRANSMISSION COSTS TO MOVE QF**

1 **OUTPUT IN A LOAD POCKET BE CALCULATED AND ACCOUNTED FOR?**

2
3 **Q. Did PacifiCorp make a recommendation on load pocket issues earlier in this**
4 **case?**

5
6 **A.** Not really. PacifiCorp's opening testimony and much of its response testimony is
7 directed toward justifying the need to charge QFs for load pocket costs. This
8 issue was already resolved by the Commission, and is not in dispute in Phase II.
9 PacifiCorp finally made its actual recommendations and provided its justification
10 in response testimony, which only allowed the parties two weeks to review and
11 respond.

12 **Q. What is PacifiCorp's recommendation?**

13
14 **A.** That all QFs should be required to purchase the most expensive form of
15 transmission, regardless of whether there may be lower cost alternatives that
16 provide sufficient reliability and value to ratepayers and the utility. PAC/1300,
17 Griswold/16-19. Also, the company recommends that QFs should not be
18 compensated if other transmission customers can use the third party transmission
19 that is purchased for them and saves the company money. Id. at Griswold/15-17.
20 While PacifiCorp's position has moved closer to mine on the treatment of existing
21 QFs, the company proposes that some existing QFs should be required to pay for
22 third party transmission costs, even if they did not cause them to be incurred. Id.
23 at Griswold/20-21.

24 In addition, it is unclear how many varying circumstances of load pocket
25 issues will be treated, what the implications might be to power purchase processes
26 and the standard form of agreement. It appears that below the surface of a broad

1 proposed policy application is a myriad of undiscussed and unresolved issues of
2 significance. Unilateral requirements and applications of third-party transmission
3 requirements and costs could easily become another tool for discouraging QFs,
4 including those that already exist and had not contributed to load-pocket creation.

5 **Q. Do you agree that long term firm point to point transmission is the only way**
6 **to ensure that the QF reliably meets its obligations?**

7
8 **A.** No. I believe my previous testimony, and that of the Oregon Department of
9 Energy, the Commission Staff, and the Community Renewable Energy
10 Association have adequately rebutted this position. In addition, PacifiCorp's past
11 practices using other transmission for QFs in load pockets also adequately rebuts
12 this position.

13 I only add a couple points. One, it is in the QF's economic interest is to
14 ensure that its generation is transmitted to PacifiCorp's load. Under current
15 standard contracts, QFs do not receive payments based on their nameplate size to
16 reflect their capacity value. Instead, QFs are now only paid for their energy and
17 capacity value when they actually generate electricity. Therefore, QFs are
18 seeking the lowest cost way to get their power to load so that they can be paid.

19 Two, PacifiCorp's approach could produce absurd results. Assume a 10
20 MW QF is in a load pocket, and that for 364 days and 23 hours of the year there is
21 adequate transmission to transmit the QF's entire generation to PacifiCorp's load.
22 Therefore, there is only one hour of the year in which there is insufficient
23 transmission to transmit the QF's generation to PacifiCorp's load. PacifiCorp
24 would require the QF to pay for 10 MWs of firm point to point transmission for

1 every day and hour of the year, even if that 10 MWs is only needed one hour of
2 the year. It would be unreasonable not to use lower cost alternatives to move the
3 generation to load.

4 **Q. Do you agree with PacifiCorp's position on existing QFs?**

5
6 **A.** In part.

7 PacifiCorp changed its position from what it stated in discovery, and now
8 agrees that an existing QF should not lose its network resource status if its
9 contract expires, unless it shuts down permanently. PAC/1300, Griswold/20-21.
10 We appear to be in agreement on this issue.

11 PacifiCorp also appears to agree that an existing QF should not be
12 required to purchase third party transmission that is required because a new QF
13 creates a load pocket. I agree, but this should not be limited to the creation of a
14 load pocket that is created because of new QF generation. The existing QF
15 should not lose its status regardless of whether the new generation is a QF, a
16 utility owned resource, an independent power producer, or another type of
17 generation. It is unclear what the company's position is regarding load pockets
18 created by generation resources that are not QFs.

19 Mr. Griswold and I disagree about whether the QF should be responsible
20 for third party transmission costs when the load pocket was not created because of
21 the QF, but because of a loss of retail load. Mr. Griswold testifies that "where
22 load has dropped significantly and the QF upon PPA renewal is now in excess of
23 load, then the QF would be responsible of the cost of transmission service."

24 PAC/1300, Griswold/21. The existing distribution and transmission system has

1 been built around the assumption of the QFs continued operations. In addition,
2 PacifiCorp has greater control over the existence of its load in terms of the rates
3 and service quality than the QF. PacifiCorp's rapidly increasing rates and service
4 quality issues should not harm QFs as well as end use consumers.

5 Ultimately, the issue of the creation of a load pocket because of retail load
6 changes comes down to fairness and equal treatment. If the QF disappears and
7 PacifiCorp needs to acquire third party transmission to move its own power to
8 serve its load, then PacifiCorp is not proposing that the QF be paid a higher
9 avoided cost rate to reflect the real value associated with the company not needing
10 to build or acquire third party transmission. Similarly, if the load disappears and
11 PacifiCorp needs to acquire third party transmission to move the QF power to
12 serve the company's load, then the QF should not have to pay these transmission
13 costs. In the event that the Commission adopts PacifiCorp's position, the
14 company should be required to perform a transmission analysis regarding the
15 transmission impacts that would occur if the company's existing QFs disappeared,
16 and these QFs should be paid for the transmission benefits they provide to the
17 company.

18 **OTHER ISSUES**

19
20 **Q. Do you have a position on the remaining issues in the case?**

21 **A.** I have no further testimony on the remaining issues in the case, as there is
22 sufficient evidence in the record already or I expect that other parties will
23 adequatley respond to them. My silence on any issue should not be construed as
24 support for any party's position.

1 **CONCLUSION**

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

3 **A. Yes.**