

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of :
PacifiCorp for Approval of an IRP-based : Docket No. 03-035-14
Avoided Cost Methodology for QF :
Projects Larger than Three Megawatts :
:

REBUTTAL TESTIMONY OF

PHILIP HAYET

ON BEHALF OF
THE COMMITTEE OF CONSUMER SERVICES

September 8, 2005

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1 **INTRODUCTION**

2 **Q. ARE YOU THE SAME PHILIP HAYET THAT FILED DIRECT**
3 **TESTIMONY IN THIS DOCKET ON BEHALF OF THE COMMITTEE OF**
4 **CONSUMER SERVICES?**

5 A. Yes I am.

6 **SUMMARY AND RECOMMENDATIONS**

7 **Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?**

8 A. Several parties filed direct testimony with the Commission in response to
9 the Company's request for an application for approval of a Differential
10 Revenue Requirement ("DRR") avoided cost method for qualifying facility
11 ("QF") projects between three and 99 megawatts ("MWs") in size. I
12 discuss the Committee's positions regarding issues raised in various
13 parties' testimonies.

14 **Q. WHICH OF THE WITNESSES' TESTIMONY DO YOU ADDRESS?**

15 A. I address issues that were introduced by Dr. Rich Collins on behalf of
16 Wasatch Wind, LLC, Mr. Roger Swenson, who filed two pieces of
17 testimony, one on behalf of U.S. Magnesium, LLC. and another on behalf
18 of Pioneer Ridge, LLC., and Mr. Neal Townsend and Mr. Scott Gutting on
19 behalf of the UAE Intervention Group. I offer no testimony to rebut any of
20 the Division's witnesses, Dr. Artie Powell, Ms. Andrea Coon, or Dr.
21 Abdinasir Abdulle, as the Committee's positions are generally consistent
22 with the Division's position.

1 **Q. PLEASE SUMMARIZE THE ISSUES YOU ADDRESS IN YOUR**
2 **REBUTTAL TESTIMONY.**

3 A. The issues I address are as follows:

- 4 **1. Attributes of an avoided cost method** – The Committee agrees
5 with parties who believe the avoided cost method should be
6 accurate, flexible, transparent, predictable, understandable, and
7 easy-to-use. The DRR method satisfies these criteria better than
8 any other avoided cost method.
- 9 **2. Conflict resolution process** – The Committee agrees with parties
10 who believe a timely conflict resolution process is very important.
11 However, the Committee does not believe that any additional
12 mechanisms to resolve conflicts need to be established.
- 13 **3. Data Modeling Improvements** – In addition to the
14 recommendations for modeling improvements that the Committee
15 raised in its direct testimony, the Committee finds there are some
16 data modeling issues that should also be corrected. This includes
17 changes that would result in all CCCT units having similar data
18 assumptions, and would incorporate wind resources in the base
19 case.
- 20 **4. Avoided transmission capital cost payments** – Payments for
21 avoided transmission capital costs should be made if a
22 transmission study can demonstrate that the QF will allow
23 PacifiCorp to avoid transmission investment costs.
- 24 **5. Avoided transmission energy losses** – Payments for avoided
25 energy losses should be made if a transmission study can
26 demonstrate that the QF will allow PacifiCorp to avoid transmission
27 energy losses.
- 28 **6. Avoided capacity payments prior to 2009** – PacifiCorp's IRP
29 2004 indicates a need to procure up to 1200 MW of firm market
30 purchases prior to 2009, when its next large resource is scheduled
31 to come on-line. These firm market purchases could be avoided if
32 PacifiCorp purchases firm QF energy. The Committee believes
33 that some partial avoided capacity payment should be made to QFs
34 over the 2006 – 2009 time period along the lines suggested in Mr.
35 Townsend's testimony.
- 36 **7. 20 year contract life** – The Committee opposes extending the
37 contract length for a QF beyond 20 years. Twenty years is a
38 reasonable length for any developer to get financing for a QF
39 project.

1 **8. Wind Integration Costs** – The Committee raised an issue in its
2 direct testimony of whether there might be a way to more
3 accurately determine the level of wind integration costs using
4 PacifiCorp’s GRID model. PacifiCorp believes it may have a way
5 to do this, but it appears unlikely that it will be tested in time for the
6 hearing. The Committee recommends using \$4.64/MWh for now,
7 but the Commission should order PacifiCorp to conduct a detailed
8 analysis of wind integration costs using GRID.

9 **9. Wind QF Capacity Payments** – The Committee addressed wind
10 QF capacity payments in its direct testimony. Based on the
11 testimony of other parties and discussions in technical conferences,
12 the Committee amends its position. However, this only applies to
13 wind QFs that help bring PacifiCorp’s total wind capacity up to the
14 amount that PacifiCorp’s IRP 2004 determined to be economic,
15 which is 200 MW per year and 1,400 MW total. For wind QFs that
16 this applies to, the Company should be indifferent to paying them
17 something similar to what the IRP determined to be the cost the
18 Company would have to pay for wind energy. When the total
19 amount of acquired wind capacity on PacifiCorp’s system exceeds
20 the limit, then the Committee’s recommendation from its direct
21 testimony should apply.

22

23 **COMMITTEE’S DRR RECOMMENDATION**

24 **Q. HAVING REVIEWED OTHER PARTIES’ DIRECT TESTIMONY, DOES**
25 **THE COMMITTEE STILL BELIEVE THAT THE DRR AVOIDED COST**
26 **METHOD IS SUPERIOR TO ALTERNATIVE METHODS FOR**
27 **CALCULATING AVOIDED COSTS?**

28 **A.** The Committee is even more convinced that the DRR method is the most
29 accurate method for calculating avoided costs. The DRR method
30 captures the complex interactions of the PacifiCorp system and has the
31 flexibility to model the characteristics of any type of QF willing to supply
32 power to PacifiCorp. We believe various parties’ proxy approaches tend

1 to overstate PacifiCorp's avoided costs and should be rejected by the
2 Commission.

3 **Q. PLEASE BRIEFLY REVIEW THE DRR AVOIDED ENERGY COST**
4 **METHOD.**

5 A. The DRR method requires two production cost runs to be made. In the
6 first run PacifiCorp's system is modeled without the QF; in the second run
7 PacifiCorp's system includes the QF as a zero cost resource. The
8 difference in production costs between the two runs represents the
9 maximum amount that could be paid to the QF without increasing costs to
10 customers. Thus, the avoided energy cost rate (\$/MWh) is the production
11 cost savings divided by the energy supplied by the QF.

12 **Q. WAS THIS THE SAME DRR METHOD THAT PACIFICORP**
13 **RECOMMENDED IN ITS DIRECT TESTIMONY?**

14 A. In essence it was, however, the Company included certain steps that the
15 Committee recommended should be removed.

16 **Q. PLEASE EXPLAIN THE COMMITTEE'S RECOMMENDED**
17 **ADJUSTMENTS.**

18 A. The Company added not only the QF requesting indicative pricing in the
19 second run, but also a second QF modeled as a 525 MW zero cost, 100%
20 capacity factor, unit. With the addition of this second unit, PacifiCorp also
21 removed the 525 MW CCCT unit identified in its IRP 2004. The
22 Committee found this step to be inappropriate and recommended
23 eliminating it.

1 **Q. WILL THE COMMITTEE'S RECOMMENDED CHANGES ADDRESS**
2 **SIMILAR CONCERNS RAISED BY OTHER PARTIES IN THEIR**
3 **TESTIMONIES?**

4 A. We believe it will. As explained in the Committee's direct testimony, it is
5 unreasonable to remove an IRP CCCT resource operating at a 38%
6 capacity factor and replace it with a 100% capacity factor resource of the
7 same size. This step is simply unnecessary. Adding the 100% capacity
8 factor resource and removing the IRP unit causes problems in that a
9 significant amount of low cost coal energy ends up being avoided, which is
10 unrealistic.

11 **Q. HAS THE COMMITTEE WORKED WITH THE COMPANY TO TEST THE**
12 **ROBUSTNESS OF THE DRR RESULTS BASED ON THE**
13 **COMMITTEE'S REVISED DRR METHOD?**

14 A. Yes, we agreed that it would be beneficial to test the DRR results based
15 on the Committee's recommended DRR method using a range of capacity
16 factor assumptions. Common sense suggests that a QF with a low
17 capacity factor (operating for just a few hours each day near the daily
18 peak) should achieve higher avoided energy costs than a QF operating
19 nearly every hour of each day. By examining QFs having different
20 capacity factors, we agreed that we could determine if the revised DRR
21 method produces reasonably expected results. PacifiCorp performed a
22 series of analyses to test the method, and the Committee submitted DR
23 15.4 to PacifiCorp to obtain the results.

1 **Q. DID THE COMMITTEE ALSO RECOMMEND AN ADDITIONAL**
2 **MODELING CHANGE IN ITS DIRECT TESTIMONY THAT IT HAD NOT**
3 **EVALUATED AT THE TIME?**

4 A. Yes, the Committee recommended another adjustment in the second run,
5 which was to reduce the size of the 2009 IRP resource by the capacity of
6 the QF resource that had been added in the second run. This change
7 should be implemented because the QF resource is able to displace an
8 equivalent amount of IRP capacity that no longer has to be added to the
9 system. PacifiCorp evaluated this adjustment as well.

10 **Q. WHAT ANALYSES WERE PERFORMED AND WHAT AVOIDED COST**
11 **ENERGY RESULTS WERE OBTAINED?**

12 A. Four QF cases were examined, each having a different QF capacity factor
13 assumption associated with a 99 MW QF. The table below provides the
14 capacity factor assumption and the 20-year levelized avoided energy cost
15 results derived from each of the four cases that were analyzed.

16

Capacity Factor	PacifiCorp Revised Avoided Energy Costs (\$/MWh)
100% capacity factor	\$38.42
85% capacity factor	\$40.77
70% capacity factor	\$43.79
High Load Hours only – 57% capacity factor	\$47.37

17

18

1 **Q. HOW DO YOU INTERPRET THESE AVOIDED ENERGY COST**
2 **RESULTS?**

3 A. The 100% capacity factor case is effectively the same as the Committee's
4 100% capacity factor case included in my direct testimony. In that
5 testimony, the Committee's levelized avoided energy cost was
6 \$39.21/MWh, which is slightly higher than the \$38.42/MWh obtained in
7 this 100% capacity factor case. The difference is explained by the fact
8 that PacifiCorp implemented the Committee's additional recommendation
9 of reducing the size of the IRP resource in the second run by the size of
10 the QF resource, in this case a 99 MW unit. This result appears intuitively
11 correct because lower avoided energy costs would be expected when
12 removing capacity from the second run.

13 **Q. DO THE RESULTS FOR THE DIFFERENT CAPACITY FACTOR CASES**
14 **APPEAR REASONABLE?**

15 A. Yes. As a QF's capacity factor is lowered in each successive run the
16 average avoided cost increases, as would be expected. Stated differently,
17 the QF becomes more of a premium product when energy is provided in
18 fewer hours that are closer to the peak, and therefore, as the capacity
19 factor is reduced the QF provides increasingly greater value to the utility.
20 When the QF is only dispatched during high load hours, the QF provides
21 the greatest benefit to the utility and it receives the highest energy avoided
22 costs of all the cases.

23 **Q. WOULD A PROXY METHOD PRODUCE SIMILAR RESULTS?**

1 A. No. Proxy methods typically use simplifying assumptions that result in
2 higher avoided energy costs vis-à-vis the DRR method. As Mr. Townsend
3 states in his testimony,

4 *“Of necessity, the proxy model uses some simplifying*
5 *assumptions. The results are reasonable so long as a few*
6 *critical assumptions are reasonable. The most important*
7 *assumption for a reasonable energy price is the expected*
8 *capacity factor of the avoidable resource, the 2009 CCCT*
9 *plant in this case” (Neal Townsend Direct Testimony, for*
10 *UAE, Page 12, Line 17)*
11

12 Also, as Mr. Swenson states in his testimony,

13 *“One shortfall of the Proxy method is that the pricing of*
14 *avoided costs is most accurate if the QF and the avoided*
15 *resource operate in the same manner. For example, if the*
16 *Proxy resource is a CCCT and will be dispatched 45%-60%*
17 *of the time, then the QF Proxy pricing approach will be*
18 *extremely accurate for that 45%-60% of the time, in the*
19 *dispatch hours. If the QF operates outside the dispatch*
20 *hours, some other pricing mechanism must be applied to*
21 *find the ratepayer indifference price, such as one that relies*
22 *upon a market index.”*
23

24 Because of the simplifying assumptions associated with the proxy method,
25 both Mr. Townsend and Mr. Swenson had to find an alternative
26 mechanism to price hours outside of the typical dispatch period of the QF
27 resource. UAE’s proxy method derives average avoided energy costs by
28 blending the costs of a CCCT unit, for the time that the CCCT would be
29 expected to run (57% of the hours), with the costs of market purchases
30 from Palo Verde for the time period outside of the typical dispatch period
31 of a CCCT unit (43% of the hours).

1 **Q. DO YOU AGREE THAT A SIMPLE BLENDING OF CCCT AND PALO**
2 **VERDE MARKET PRICES IS REASONABLE FOR USE IN COMPUTING**
3 **PACIFICORP'S AVOIDED COSTS?**

4 A. No, I do not. First, all these results assume that every QF will supply
5 power to PacifiCorp in a pattern similar to the operation of a CCCT unit.
6 That is an unreasonable assumption. Second, PacifiCorp operates its
7 system using a wide range of resources, including low energy cost coal,
8 hydro, wind and geothermal resources and higher energy cost gas-fired
9 and purchase power resources. During certain hours, PacifiCorp's
10 avoided energy costs would closely track the costs of CCCT resources
11 and/or Palo Verde energy; however, in other hours, it is quite likely that
12 PacifiCorp's avoided energy costs would be based on the lower energy
13 costs associated with operating coal-fired generation. Calculating
14 PacifiCorp's avoided energy costs every hour strictly on the basis of
15 CCCT and/or Palo Verde energy costs will overstate PacifiCorp's avoided
16 energy costs.

17 **Q. DID MR. TOWNSEND DERIVE AVOIDED ENERGY COSTS FOR QFS**
18 **HAVING DIFFERENT OPERATING CHARACTERISTICS?**

19 A. UAE presented avoided energy cost results both in Mr. Townsend's direct
20 testimony and in response to Committee data requests CCS 1.8, CCS 1.9,
21 and CCS 1.10. For each of these analyses, UAE computed avoided
22 energy costs for QFs having different capacity factor assumptions. The
23 following table compares the results of UAE's avoided energy costs for

1 three different capacity factor cases.

Capacity Factor	UAE Avoided Energy Costs (\$/MWh)	CCCT Weighting Factor	Palo Verde Weighting Factor
100% capacity factor	\$51.69	57%	43%
85% capacity factor	\$51.69	57%	43%
High Load Hours only (57% capacity factor)	\$53.70	100%	0%

2

3 No difference exists in the avoided energy cost of the 100% and 85%
 4 capacity factor cases because UAE used the same weighting factors for
 5 the two cases. In the 57% capacity-factor case the weighting factor was
 6 changed and the avoided energy cost increased to \$53.70/MWh. Notably,
 7 there is very little difference in the avoided energy costs derived in the
 8 three cases.

9 **Q. CAN YOU PROVIDE A SIMPLE EXAMPLE THAT DEMONSTRATES**
 10 **THE IMPACT OF HOW THESE COSTS MIGHT HAVE BEEN**
 11 **COMPUTED HAD ENERGY FROM COAL RESOURCES BEEN**
 12 **INCLUDED IN THE WEIGHTING?**

13 A. Based on UAE's high load hour case (CCCT weighting factor equal to
 14 100%) UAE's levelized avoided energy cost is \$53.70/MWh.¹ For the
 15 sake of simplicity, assume that in one particular year the avoided energy
 16 cost also computes to \$53.70/MWh. Using UAE's heat rate assumption for
 17 a CCCT unit (7.599 MBtu/MWh), the gas price for this year could be
 18 calculated as \$7.07/MBtu (53.7 / 7.599). Had coal energy been included

¹ Based on a 20-year stream of costs and with different fuel costs in each year.

1 in the proxy formula, using an 85% CCCT / 15% Coal weighting
 2 assumption, then the avoided energy cost for that year would have been
 3 lower than \$53.70/MWH. For example, assume that the heat rate of a
 4 coal unit is 10.5 MBtu/MWh and its fuel cost is \$1.2/MMBtu, then the
 5 avoided energy cost of a proxy that blends costs attributable to both gas
 6 and coal resources would be approximately:

CCCT	$(7.599 \text{ MBtu/MWh} * \$7.07/\text{MBtu}) * .85 =$	\$45.67/MWh
Coal	$(10.500 \text{ MBtu/MWh} * \$1.2/\text{MBtu}) *.15 =$	\$1.89/MWh
	Weighted Average Avoided Energy Cost =	\$47.56/MWh

8
 9 This is very close to the levelized avoided energy cost that PacifiCorp
 10 calculated using the DRR approach assuming that the QF operates during
 11 the high load hours.

12 **Q. WHY NOT SIMPLY REVISE THE PROXY APPROACH TO BLEND IN**
 13 **THE PRICE OF COAL RESOURCES AS PART OF THE FORMULA?**

14 A. The biggest problem is determining what the appropriate weighting factors
 15 should be. It is very difficult to determine whether coal costs should be
 16 weighted by 10%, 15% or some other value without using a production
 17 cost model. Therefore, the DRR method, which is predicated on
 18 production cost modeling, is the more accurate approach to compute
 19 PacifiCorp's avoided energy costs.

1 **COMMITTEE'S POSITIONS REGARDING OTHER ISSUES**

2 **1. Attributes Of An Avoided Cost Method**

3 **Q. PLEASE DISCUSS THE KEY ATTRIBUTES THAT AN AVOIDED COST**
4 **METHOD SHOULD HAVE.**

5 A. Two of the witnesses for UAE, Mr. Neal Townsend and Mr. Scott Gutting
6 expressed the need for an avoided cost method that is flexible,
7 transparent, predictable, understandable and easy-to-use. Dr. Collins, on
8 behalf of Wasatch Wind LLC. expressed a concern that developers should
9 not have to hire experts to run the model and verify results. While the
10 Committee realizes that the DRR method may be more complicated than
11 a proxy approach, the advantages of using it far outweigh the
12 disadvantages. First, the DRR method is a considerably more accurate
13 and flexible tool for calculating avoided energy costs. Second, as parties
14 gain experience with using the DRR method they can conduct a variety of
15 tests that will make the model more transparent to them. The fact that
16 PacifiCorp provides GRID to parties for free could actually help the
17 developer save money, as some developers in other jurisdictions have
18 had to hire consultants and pay for software license fees to analyze
19 production cost results developed by the utility.

20 **2. Conflict Resolution**

21 **Q. PLEASE DISCUSS THE COMMITTEE'S POSITION CONCERNING**
22 **CONFLICT RESOLUTION.**

1 A. The Committee agrees that a timely conflict resolution process is very
2 important, not only for the QF, but also for PacifiCorp. However, the
3 Committee does not believe that any additional mechanism to resolve
4 conflicts is necessary. Should a conflict arise, parties already have the
5 right to petition the Commission for a hearing to resolve the issue. The
6 Commission has proven quite adept at holding hearings and addressing
7 conflicts on an expedited manner such as the recent hearings held to
8 address Spring Canyon's QF issues.

9 **3. Data Modeling Improvements**

10 **Q. CERTAIN PARTIES PROPOSED DATA MODELING CORRECTIONS**
11 **TO THE DRR METHOD. DO YOU AGREE WITH THOSE PROPOSED**
12 **MODELING CORRECTIONS?**

13 A. In addition to the Committee's recommended changes to the Company's
14 DRR approach, both Mr. Townsend and Dr. Collins identified data
15 modeling inconsistencies that should also be corrected. Mr. Townsend
16 pointed out that the 2009 CCCT IRP resource is modeled with different
17 heat rate and fuel cost assumptions compared to the Currant Creek and
18 Lakeside CCCT units. Most likely these data inconsistencies account for
19 the fact that some of the CCCT units appear to produce differing amounts
20 of energy compared to other CCCT units in the Company's GRID runs.
21 The Committee believes that the Company should revise the inconsistent
22 data unless it can provide a reasonable explanation for the differences in
23 data input assumptions.

1 **Q. ARE YOU SURPRISED BY FINDING THESE SORTS OF DATA**
2 **DISCREPANCIES?**

3 A. Not at all. PacifiCorp undertook a significant modeling effort when it
4 prepared to file testimony in this docket, including setting up a completely
5 new GRID database that contained all of the Company's IRP 2004
6 modeling assumptions. The fact that some data inconsistencies may have
7 arisen in the process of setting up a new database is not at all surprising.
8 Furthermore, once a legitimate problem is identified, I have no reason to
9 doubt that PacifiCorp would strive to fix it as quickly as possible. The fact
10 that Mr. Townsend found these data inconsistencies indicates that the
11 GRID model is not a black box as certain people in this case have
12 suggested. It also indicates that PacifiCorp, the Division and the
13 Committee are not the only parties capable of reviewing input data
14 assumptions and analyzing output results in order to check for
15 reasonableness.

16 **Q. DID ANY OTHER PARTY NOTICE ANY OTHER DATA**
17 **INCONSISTENCY THAT SHOULD BE CORRECTED?**

18 A. Dr. Collins pointed out another problem in the database, which the
19 Company actually discussed in Mr. Duvall's direct testimony. When the
20 Company set up the new GRID database it included all future IRP
21 resources except for wind resources. Mr. Duvall explained that the
22 Company assumed that some of the IRP wind resources will be QF
23 resources and were consequently left out of the base case. I agree with

1 Dr. Collins that all IRP resources need to be included in the base case,
2 including the wind resources.

3 **4 & 5 Avoided Transmission Capital Cost Payments & Avoided**
4 **Transmission Energy Losses**

5 **Q. DO YOU BELIEVE THAT QFS SHOULD RECEIVE AVOIDED**
6 **TRANSMISSION CAPACITY AND AVOIDED TRANSMISSION ENERGY**
7 **LOSS PAYMENTS?**

8 A. The Committee believes that transmission capacity and transmission
9 energy loss payments should be considered in the avoided cost analysis.
10 However, these transmission-related costs may be positive or negative
11 values depending on where the QF is located on PacifiCorp's transmission
12 system. To determine the sign and magnitude of the transmission-related
13 costs, PacifiCorp's transmission business unit should conduct a
14 transmission network analysis. The analysis should demonstrate whether
15 or not the QF will cause PacifiCorp to defer transmission capital expenses,
16 as well as avoid transmission energy losses.

17

18 The transmission business unit will have to conduct two transmission
19 simulations; a base case without the QF and a second case with the QF.
20 If PacifiCorp's transmission capital costs or its transmission energy losses
21 decrease as a result of the QF locating on its system, then the QF is
22 entitled to a transmission capacity payment and a transmission energy
23 loss payment. However, it is also possible that PacifiCorp's transmission

1 capital costs or its transmission energy losses may actually increase as a
2 result of where the QF locates on the transmission system. Therefore, it
3 may be appropriate to assess transmission capacity and transmission
4 energy loss charges, which would effectively reduce a QFs avoided cost
5 payments.

6 **Q. WILL THIS RESULT IN ADDITIONAL COMPLEXITIES IN**
7 **DETERMINING A QF'S TOTAL AVOIDED COSTS?**

8 A. To a certain extent it will; however, QFs between 3 MW and 99 MW are
9 reasonably large generating units and transmission analyses should be
10 required for those QF units to interconnect with PacifiCorp's system.² The
11 Committee believes this is a fundamentally better approach than what has
12 been proposed by either Mr. Townsend or Dr. Collins. Mr. Townsend
13 derives a cost of \$185/kW for transmission construction costs based on
14 assumptions from IRP 2004 and he proposes that figure be used to
15 determine transmission capacity payments. Dr. Collins relies on
16 information from IRP 2003 and he proposes that a \$100/kW transmission
17 construction cost estimate be used to determine transmission capacity
18 payments. The Committee suspects that both of these estimates might
19 overstate PacifiCorp's actual avoided transmission capacity costs.
20 Therefore, the Committee recommends that the Commission order
21 PacifiCorp to conduct transmission network studies to more accurately
22 determine the magnitude of the transmission capital costs and the

1 transmission energy losses that should be used for purposes of adjusting
2 avoided cost payments to QFs.

3 **6. Avoided Capacity Payments Prior To 2009**

4 **Q. SHOULD PACIFICORP BE REQUIRED TO MAKE AVOIDED**
5 **CAPACITY PAYMENTS PRIOR TO 2009?**

6 A. Despite the fact that PacifiCorp's IRP 2004 calls for up to 1200 MW of firm
7 market purchases prior to 2009, the Company proposes to start making
8 avoided capacity payments to QFs beginning in 2009.³ UAE has
9 suggested that PacifiCorp should make avoided capacity payments
10 beginning in 2006 to reflect the fact that these firm market purchases are
11 potentially avoidable resources. The Committee concurs with UAE that
12 firm market purchases are potentially avoidable resources. Therefore,
13 PacifiCorp cannot simply assume that QF resources will only begin
14 providing a capacity value starting in 2009. Given that PacifiCorp has a
15 capacity need starting in 2006, the Committee recommends that an
16 appropriate level of avoided capacity payments should begin as early as
17 2006.

18 **Q. HAS THE COMMITTEE REVIEWED THE CAPACITY PAYMENT**
19 **PROPOSAL SET FORTH BY UAE WITNESS TOWNSEND AND DOES**
20 **THE COMMITTEE FIND IT TO BE A REASONABLE PROPOSAL?**

² Typically both a transmission interconnection study and a system impact study must be performed for any generator that wants to deliver power to PacifiCorp.

³ These firm market purchases are referred to as Front Office Transactions in the IRP 2004 report.

1 A. The Committee has examined UAE's capacity payment recommendation
2 and finds it to be reasonable. Specifically, Mr. Townsend proposes a
3 payment stream that results in the same 20-year levelized capacity
4 payment being made to the QF, yet it begins in 2006 instead of 2009. The
5 following table compares the avoided capacity payments using the
6 Company's original capacity payments (payments starting in 2009), with
7 an alternative payment stream beginning in 2006 as recommended by Mr.
8 Townsend.

	PacifiCorp Payment	UAE Proposed Spread
Year	Capacity Price \$/kW-yr	Capacity Price \$/kW-yr
2006	\$0.00	\$61.43
2007	\$0.00	\$62.67
2008	\$0.00	\$63.94
2009	\$82.51	\$65.23
2010	\$84.18	\$66.55
2011	\$86.66	\$68.50
2012	\$89.20	\$70.52
2013	\$91.83	\$72.59
2014	\$94.53	\$74.72
2015	\$97.31	\$76.92
2016	\$100.17	\$79.18
2017	\$103.11	\$81.51
2018	\$106.14	\$83.91
2019	\$109.26	\$86.37
2020	\$112.48	\$88.91
2021	\$116.91	\$92.42
2022	\$121.51	\$96.06
2023	\$126.30	\$99.84
2024	\$131.28	\$103.78
2025	\$136.45	\$107.86

20 Year Levelized Prices (Nominal) @ 7.20% Discount Rate
 \$/kW 74.94 74.94

1

2 Over the 20-year life, the results show that the levelized avoided capacity
 3 payments will be identical.

4 **7. 20-year Contract Life**

5 **Q. WHAT ARE THE PARTIES CONCERNS REGARDING THE QF**
 6 **CONTRACT LENGTH?**

7 A. Some parties have expressed concerns that PacifiCorp's proposed QF
 8 contract length of 20 years is too short and should be extended to the life
 9 of QF resources (up to 35 years). The Committee believes that it is

1 unreasonable to require PacifiCorp to enter into contractual obligations for
2 such excessively long periods. The Public Utility Commission of Oregon
3 (“PUCO”) holds a similar view. In a recent decision by the PUCO, the
4 contract length for QF projects was increased from five to 15 years, with
5 an additional 5-year extension period, bringing the total contract length to
6 20 years.⁴ In its final order the Commission opined:

7 *We conclude that establishing an appropriate maximum term*
8 *for standard contracts requires us to balance two goals. A*
9 *primary goal in this proceeding is to accurately price QF*
10 *power. We also seek, however, to ensure that QF projects*
11 *that are deemed eligible to receive standard contracts have*
12 *viable opportunities to enter into a standard contract. To*
13 *achieve this latter goal, it is necessary to ensure that the*
14 *terms of the standard contract facilitate appropriate financing*
15 *for a QF project. Consequently, we agree with Staff and*
16 *other parties that our fundamental objective is to establish a*
17 *maximum standard contract term that enables eligible QFs*
18 *to obtain adequate financing, but limits the possible*
19 *divergence of standard contract rates from actual avoided*
20 *costs.*
21

22 There was considerable debate over whether the appropriate length for a
23 QF developer to be able to get project financing should be 15 or 20 years.
24 Ultimately, the Commission determined that the evidence on contract
25 length was inconclusive, but it appears that most of the parties were
26 comfortable with a 20-year term.

27 **Q. WHAT DOES THE COMMITTEE RECOMMEND REGARDING THE**
28 **CONTRACT TERM?**

⁴ Public utility commission of Oregon, Docket UM 1129, Order No. 05-584, May 13, 2005, Staff’s Investigation Relating to Electric Utility Purchases From Qualifying Facilities.

1 A. Twenty-year contract terms have allowed developers to get financing for
2 their projects. Therefore, we recommend that the contract term be limited
3 to 20 years.

4 **8. Wind Integration Costs**

5 **Q. PLEASE DISCUSS THE COMMITTEE POSITION REGARDING WIND**
6 **INTEGRATION COSTS.**

7 A. A utility incurs costs to integrate wind resources into its system. These
8 wind integration costs should be treated as a reduction in payments to
9 wind QFs. In my direct testimony, I raised the possibility of more
10 accurately determining these costs within PacifiCorp's production cost
11 model. While PacifiCorp believes there may be a way to model wind
12 integration cost impacts within GRID modeling, it has yet to test this
13 modeling approach. Therefore, the Committee recommends: (1)
14 PacifiCorp's estimate of \$4.64/MWh should be used on an interim basis to
15 lower payments to wind QFs for integration costs; and (2) the Commission
16 should order PacifiCorp to conduct a more detailed analysis of wind
17 integration costs to determine if those costs could be more accurately
18 captured within GRID.

19 **9. Wind Resource Payments**

20 **Q. HAS THE COMMITTEE RECONSIDERED ITS WIND QF CAPACITY**
21 **PAYMENT POSITION?**

22 A. From reviewing other parties' testimony and through discussions held
23 during technical conferences, the Committee has reconsidered its position

1 regarding wind QF capacity payments. We now recommend that special
2 treatment should be afforded wind QF resources that supply PacifiCorp
3 with capacity that helps bring PacifiCorp's total wind capacity up to the
4 limits specified in PacifiCorp's IRP 2004, 200 MW per year and 1,400 MW
5 in total. Once those limits are reached, then the Committee's
6 recommendation in its direct testimony should be relied upon with regard
7 to the avoided capacity payment.

8 **Q. PLEASE DISCUSS WHY WIND RESOURCES THAT MEET THESE**
9 **CONDITIONS SHOULD BE AFFORDED THIS SPECIAL TREATMENT?**

10 A. PacifiCorp determined that it would be economic to add approximately 200
11 MW of wind per year, and up to 1,400 MW total. As part of implementing
12 its IRP action plan, PacifiCorp has signed some wind contracts and is
13 working to add more wind resources to its system. In meeting the goals
14 that the Company established in IRP 2004, it makes no difference whether
15 a wind resource is acquired through an RFP solicitation or through a QF
16 contract. Customers should be indifferent to paying, for example,
17 \$40/MWh to a bidder that supplies wind energy or to a QF that supplies a
18 similar wind energy product.

19 **Q. WHAT AVOIDED COST PAYMENT DOES THE COMMITTEE PROPOSE**
20 **FOR QFs THAT FALL WITHIN THE LIMIT IT PROPOSES?**

21 A. The Committee believes that it would be fair to pay those QFs an amount
22 equal to the lessor of the levelized energy cost assumed in the IRP, and
23 the levelized energy cost from the first winning wind bidder in the

1 Company's most recent bid solicitation. This would establish the lowest
2 cost that the Company could acquire wind energy for if it was not obligated
3 to purchase that energy from a QF wind energy supplier. Dr. Collins
4 provided an example of the levelized energy cost of a wind resource as
5 Exhibit RSC-1 based on data assumptions that he obtained from IRP
6 2004. Assuming all of the calculations are correct, the levelized cost of
7 energy is \$65.53/MWh.

8 **Q. WHY DID YOU SAY "ASSUMING ALL OF THE CALCULATIONS ARE**
9 **CORRECT"?**

10 A. \$65.53/MWh appears extremely high for the levelized cost of a wind
11 resource. For example, Northwestern Energy in Montana recently
12 received Commission approval for a 150 MW wind power purchase from
13 the Judith Gap Wind Farm project in Montana. According to the Montana
14 Commission's Order approving the contract, the 20-year annual average
15 price is \$31.71/MWh.⁵ This price is less than half the price recommended
16 by Dr. Collins.

17 **Q. HAS THE COMMITTEE COMPUTED THE 20-YEAR LEVELIZED COST**
18 **USING THE ASSUMPTIONS INCLUDED IN PACIFICORP'S IRP 2004?**

19 A. Yes it has. The Committee reviewed Dr. Collins' calculation and found a
20 few items that should be revised. Committee Rebuttal Exhibit 1 is a
21 calculation of the 20-year levelized cost in \$/MWH based on IRP 2004
22 data assumptions. Most of the data assumptions were derived from

1 Tables C.27 and C.28 in PacifiCorp's IRP 2004 report. This analysis is
2 similar to Dr. Collins' analysis, with the following three differences:

- 3 • The Committee did not include a transmission capacity cost payment
4 because a transmission network study (as recommended earlier in my
5 testimony) is required to determine the value of such payment.
- 6 • We used a 35% capacity factor assumption for a wind resource, as
7 was included on Table C.38 of the IRP 2004 report. Dr. Collins,
8 whether intentionally or unintentionally, used a 32% capacity factor
9 assumption.
- 10 • The Committee corrected what it believes is improper treatment of the
11 production tax credit. Dr. Collins assumes that the production tax
12 credit would exist for the entire 20 years. However, the production tax
13 credit only applies for the first 10 years of the life of a wind resource.
14 The Committee also believes that the production tax credit must be
15 grossed up for taxes. While a more accurate value for PacifiCorp's
16 effective tax rate should be used, the Committee used 40% for
17 illustrative purposes.

18 **Q. WHAT DO THE RESULTS OF THE COMMITTEE'S ANALYSIS SHOW?**

19 A. The Committee's revisions to Dr. Collins' analysis produce a levelized cost
20 of wind energy of \$46.05/MWh. While this is still higher than the cost of
21 the Judith Gap project, it is substantially below the estimate that Dr.
22 Collins presented.

⁵ Public Service Commission of the State of Montana, Docket D2005.2.14, Final Order No.

1 **Q. ARE YOU SUGGESTING THAT THE COMMITTEE'S ESTIMATE**
2 **SHOULD BE THE VALUE USED FOR MAKING PAYMENTS TO WIND**
3 **QFS?**

4 A. The Committee provided this calculation simply for illustrative purposes
5 and to demonstrate that the avoided cost payments recommend by wind
6 resource proponents are excessive. The Committee recommends that
7 this methodology be used for wind resources that fall within the 200 MW
8 per year/1,400 MW total limit, and recommends that the Company should
9 verify that these calculations are accurate, particularly the wind power
10 production tax credit treatment.

11 **Q. DOES THIS CONCLUDE YOUR PREFILED DIRECT TESTIMONY?**

12 A. Yes, it does.