Regulation
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PACIFICORP

PACIFIC POWER • UTAH POWER

February 3, 2004

Julie Orchard
Utah Public Service Commission
Heber M. Wells Building
160 East 300 South
Salt Lake City, UT 84111

Re: Docket No. 03-035-14

Dear Ms. Orchard:

Please find enclosed for filing with the Commission PacifiCorp's direct testimony in this case. The Company's filing consists of the Direct Testimony of Mark R. Tallman, Rodger Weaver, Bruce W. Griswold, David J. Mendez and Bruce N. Williams.

Please contact me if you have any questions.

Very truly yours,

John W. Stewart
Managing Director
Utah - Regulation

CERTIFICATE OF SERVICE

I hereby certify that on this 3rd day of February, 2004, I caused to be served via overnight delivery, a true and correct copy of the foregoing to the following:

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BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

	)	
IN THE MATTER OF THE	)	Docket No. 03-035-14
APPLICATION OF PACIFICORP	)	
FOR AN ORDER APPROVING	)	
AVOIDED COST RATES	)	

FEBRUARY 2004

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF THE APPLICATION OF PACIFICORP FOR AN ORDER APPROVING AVOIDED COST RATES	)	Docket No. 03-035-14 DIRECT TESTIMONY OF MARK R. TALLMAN

FEBRUARY 2004

Q. Please state your name, business address and present position with PacifiCorp (the Company).

A. My name is Mark R. Tallman, my business address is 825 N.E. Multnomah, Suite 600, Portland, Oregon 97232, and my present position is Managing Director of Trading & Origination for the Commercial & Trading Department. My position is part of PacifiCorp's regulated merchant function.

Q. How long have you been the Managing Director of Trading & Origination at PacifiCorp?

A. I have been the Managing Director of Trading & Origination since September 12, 2003. Prior to that date, I worked in the Origination Department, first as an Originator (beginning March 1995), then as the Manager of Origination (beginning January 1999), and finally as the Director of Origination (beginning September 2000).

Q. What did you do before working in the wholesale side of PacifiCorp's business?

A. I served in a variety of different roles in PacifiCorp's engineering organization and retail distribution organization, including five years as a District Manager. I have worked at PacifiCorp for more than 18 years.

Q. Please describe your educational history.

A. I have a Bachelor of Science degree in Electrical Engineering from Oregon State University and a Masters of Business Administration from City University. I am also a Registered Professional Engineer in the states of Oregon and Washington.

Q. Have you previously appeared in any proceedings before the Utah Public Service Commission?

A. Yes. I testified in Docket No. 01-035-37 (the certificate proceeding for the Gadsby peaker project), and in Docket No. 03-035-29 (the certificate proceeding for the Currant Creek Project).

Summary of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide the Commission with an overview of PacifiCorp's case, to discuss some of the factors we believe the Commission should consider in adopting a Qualifying Facility ("QF") avoided cost methodology and to provide information about the status of QF development on PacifiCorp's system.

Q. Would you please summarize your testimony in this proceeding?

A. I explain that, in our view, the ratepayer indifference standard should be one of the critical driving factors in establishing an avoided cost method. In order to meet that standard, an avoided cost method should be able to keep pace with the Company's changing load and resource needs, as well as with changing market conditions. The method should also, as the Commission directed in its September 24, 2003 Order, be able to classify costs between capacity and energy. As Dr. Weaver discusses in his testimony, the Company's proposed method reflects those factors and is also the same as the method previously adopted by the Commission to establish avoided costs for Schedule 37. I also provide an overview of PacifiCorp's current QF purchases (range in size, total capacity, and cost) and summarize the level of interest that PacifiCorp has received from QF developers to date. Based on that information, I point out the vital importance for customers and the Company of establishing an avoided cost methodology that produces reasonable results that reflect the costs that QF purchases can truly avoid. Finally, I identify the Company's witnesses and briefly describe the subjects they address.

Factors to Consider

Q. Would you please discuss some of the factors that the Commission should consider in establishing an avoided cost method?

A. In our opinion, the "ratepayer indifference" standard should be one of the primary considerations in adopting an avoided cost model. Under the Public Utility Regulatory Policies Act of 1978 ("PURPA"), the Federal Energy Regulatory Commission ("FERC") implementing regulations and Utah's "mini-PURPA" statutes, PacifiCorp has an obligation to purchase energy and capacity from QFs in the state of Utah at Commission-approved prices. Those Commission-approved prices cannot, under PURPA and the FERC regulations, exceed the costs the QF would allow the Company to avoid. This avoided cost concept, as adopted by FERC, is designed to implement PURPA's "ratepayer indifference" standard. Under this standard, prices paid to QF projects must hold the Company's customers harmless, i.e. purchases from QF projects at those prices must not result in higher costs to customers than the costs of Company production or purchases from other suppliers.

As Dr. Weaver discusses in his testimony, the Company's proposed method will produce avoided costs that are based on its resource needs and resource alternatives. As a result, the method and those costs will be consistent with both the Company's PURPA obligations and the ratepayer neutrality standard. Another factor the Commission has directed us to consider is that the avoided cost method be able to identify the capacity cost component of the Company's avoided costs. As Dr. Weaver discusses, the Company's proposed method will be able to clearly identify the capacity cost element of the avoided cost calculation. Finally, we believe that the Commission should take into account the fact that the Company's proposed method is the same as the method previously used in this jurisdiction for avoided cost determination. The method has been analyzed in past proceedings, is based on a model familiar to regulators and has produced reasonable results, as Dr. Weaver can discuss. In addition, adopting a generic method for evaluating avoided costs provides clarity to the Commission and to potential QF developers.

QF Development

Q. Please generally describe the number and size range of the Company's QF contracts.

A. The Company currently purchases power from approximately fifty QFs ranging in size from 4 kW to 53,000 kW (or 53 MW).

Q. Please generally describe the volume of energy that the Company purchases from these QFs and the impact on purchased power costs.

A. The Company is expected to purchase more than 900,000 MWh (or 900,000,000 kWh) of energy from QF projects in fiscal year 2004 at an expected cost in excess of $75,000,000.

Q. What is the significance of this information with respect to this docket?

A. The above information underscores that QF resources are a material component of PacifiCorp's overall resource portfolio and that the impact upon net power costs can be significant. Although QF purchases represent only 1.1% of PacifiCorp's system resources on an energy basis, they make up over 11% of the Company's net power costs.

Q. Do you expect that QF resources will continue to play an important role in PacifiCorp's overall resource portfolio?

A. Yes. The above information represents nearly 200 MW of installed capacity. At the present time, PacifiCorp has a large number of QF developers who have come forth with potential new projects. These new projects range in size from 50 kW to nearly 200 MW and would be located throughout PacifiCorp's system.

Q. If all of these proposed projects were to come to fruition, what would be the total installed capacity? A. While it is hard to say if all of these projects will come to fruition, the total installed capacity would be in excess of 500 MW, or more than double the existing QF portion of PacifiCorp's portfolio. However, because PURPA does not place a maximum size limitation on cogeneration based QF projects, the impact to the Company's portfolio may ultimately be larger.

Q. What conclusion can you draw from this information?

A. I conclude, based on the potential for the Company to make material amounts of QF purchases in the future, that it is vitally important for the Commission to implement PURPA avoided cost policy in a manner such that the impact to customers and Company is consistent with the ratepayer indifference standard.

Q. Are there any other issues that you feel the Commission should take into consideration?

A. Yes. The advent of renewable energy credits ("green tags") associated with renewable resources necessitates the need for the Commission to determine if customers should be entitled to the green tags from a QF or if the owner of the QF should be able to retain the green tags.

Q. Should customers receive green tags from renewable QFs?

A. Yes. The Company believes that customers should receive the benefit of the renewable attributes that are inherent with certain QFs and that the avoided cost should be adjusted accordingly.

PacifiCorp Witnesses

Q. Would you please identify the witnesses who have prefiled testimony in this case?

A. The Company's other witnesses presenting direct testimony are as follows:

- Dr. Rodger Weaver will describe the Company's proposed methodology for determining avoided costs, and recommends Commission approval of the methodology.
- Mr. Bruce W. Griswold will discuss adjustments to the prices derived under the method described by Dr. Weaver in determining the actual price components and structure for specific QF projects.

- Mr. David J. Mendez will explain the impact on the Company's financial statements of power purchase agreements with QFs as a result of a recently adopted accounting standards.
- Mr. Bruce N. Williams will then discuss the ways in which the Company finances its operations, and the reasons why the accounting standards discussed by Mr. Mendez will impose additional costs on the Company and its customers.

Q. Does this conclude your testimony?

A. Yes

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF THE APPLICATION OF PACIFICORP FOR AN ORDER APPROVING AVOIDED COST RATES	))))))	Docket No. 03-035-14 DIRECT TESTIMONY OF RODGER WEAVER

FEBRUARY 2004

Q. Please state your name, business address and present position with PacifiCorp (the Company).

A. My name is Rodger Weaver, my business address is 825 N. E. Multnomah, Suite 800, Portland, Oregon 97232, and my present position is Director, Regulation and External Affairs Department Strategy and Planning.

Q. Please briefly describe your education and business experience.

A. I received an undergraduate degree in Economics and a PhD. in Economics from the University of Utah. I worked for the Public Service Commission of Utah from 1984-1987 and from 1987 to 1992 for the Utah Division of Public Utilities. In both positions my title was Senior Economist. I began working for PacifiCorp in 1992.

Q. Please describe your current duties.

A. In my current position, I am responsible for developing and leading the implementation of REA Company-wide strategies for meeting PacifiCorp's obligation to provide reliable and efficient electric service to its retail customers as a customer service-oriented US regulated utility.

Q. What is the purpose of your testimony?

A. My testimony describes the Company's proposed methodology for developing avoided cost-based pricing for Public Utilities Regulatory Policies Act of 1978 ("PURPA") qualifying facilities ("QFs") proposing to sell electric capacity and energy to the Company in the state of Utah and requests that the Commission adopt this method.

Q. Attached to your testimony are Exhibits UP&L___(RW-1) through UP&L___(RW-3). Were those exhibits prepared by you or under your direction?

A. Yes.

Q. As background for the following discussion, please provide a general description of the proxy and differential revenue requirement methods of calculating avoided cost rates.

A. The proxy method assumes that the fixed and variable costs of a single resource, the proxy resource, are the utility's long-run avoided costs. The differential revenue requirement method assumes an amount of zero cost QF capacity with given characteristics and calculates the utility's system cost with and without this assumed QF capacity over a specified period of years. The difference in total system costs, i.e. differential revenue requirement, between the with-QF and without-QF cases is the avoided cost for the assumed block of QF generation.

Q. Please state the overall philosophy and purpose embodied in the Company's method for developing its avoided costs.

A. In compliance with the requirements of PURPA, the Company's system avoided costs are calculated on the basis of what it would cost the Company to purchase power from others, or produce power using the Company's own generation resources, but for the power being made available by QF suppliers. Thus, in simplest terms, the Company's objective is to determine the costs the QF project allow the Company to avoid in compliance with the PURPA ratepayer indifference standard.

Q. In general terms, what is the Company's approach to computing avoided costs?

A. The approach involves two distinct steps. The first step consists of computing the capacity and energy costs a QF facility would allow the Company to avoid if it were an optimum resource which did not impose any facility-specific costs on the system. For QFs larger than one megawatt, the second step consists of identifying QF-specific characteristics affecting the extent to which the QF will, in fact, allow the Company to avoid costs at the level computed in step 1. To the extent such characteristics are identified, as Mr. Griswold discusses, these standard avoided costs will be adjusted to reflect those characteristics. Commission approval of the resulting prices will be required.

Q. What general sorts of issues would be addressed in step 2 adjustments?

A. The avoided costs computed in step 1 assume optimum QF operating characteristics associated with the Combined Cycle Combustion Turbine (CCCT) proxy resource into the Company's system. The company recognizes that this is unlikely to be the case for all new QFs located in Utah, especially as the size of the QF increases. Therefore, the adjustments discussed in Mr. Griswold's testimony are necessary to determine the costs that a specific QF will allow the Company to avoid.

Q. Are there other objectives or principles the Company's proposed method supports?

A. Yes. First, this proposal complies with the Commission's September 24, 2003 Order in this docket requiring the Company to file a method for developing indicative prices for QFs greater than 1000 kW, including a description of how capacity payments will be determined and applied. The proposed method is consistent with methodologies authorized in the Company's other jurisdictions, it is simple to calculate and easy to use and update; and it provides consistent treatment for QFs greater than and less than 1000 kW in capacity.

Q. Does your testimony address details of both step 1 and step 2?

A. No. My testimony lays out the Company's step 1 computation proposal in detail. I recommend that the Commission adopt this method for step 1. Mr. Griswold addresses the details of step 2 adjustments.

Avoided Cost Methodology

Q. Why is the Company requesting approval of its proposed avoided cost methodology at this time?

A. The Company believes it is important to have an approved methodology in place so both the Company and potential developers can effectively review potential QFs.

Q. Please describe in general terms how step 1 computed avoided cost rates are developed.

A. Step 1 computation of avoided costs is carried out in two distinct time periods: (1) a Short-Run period of energy sufficiency in which the avoided costs are based on the marginal production cost of existing resources (a differential revenue requirement approach) plus the cost of purchasing either summer or winter capacity if necessary (a proxy approach); and (2) a Long-Run period in which new resources are required to provide both summer and winter capacity and energy to meet the Company's resource requirements. In the Long-Run period, a proxy approach is used.

Q. How are the two periods delineated?

A. They are separated based on the Company's projected load and resource balance. The load and resource projections need to be made as up to date as possible.

Q. Please explain PacifiCorp Exhibit UP&L___(RW-1).

A. Exhibit UP&L___(RW-1) is a one page exhibit that summarizes the Company's load and resource overview as of October 2004. Exhibit UP&L___(RW-1) establishes the Short-Run period and the Long-Run period. The first and second sections show the summer and winter capacity load and resource balances, respectively. The third section shows the balance of energy requirements and resources. The exhibit shows that the Company would not require any new deferrable resources to satisfy energy and winter capacity resource requirements through June 2007. However, starting in 2005, new deferrable summer capacity resources, in the form of short term summer capacity purchases, are needed to satisfy summer peak capacity requirements.

Q. How were the figures developed in Exhibit UP&L___(RW-1)?

A. The Company's updated Integrated Resource Plan (IRP) filed in Utah in October 2003 provided the starting point. Some of the inputs have been updated for known changes occurring after that date. Long-term sales and purchase contracts were updated to include information available as of January 2004. These changes include the addition or revision of several long-term purchase contracts, including Powerex, Combine Hills and two Arizona Public Service purchases. While we recognize that the Commission has yet to grant a certificate for the Currant Creek plant, the Company has included the Currant Creek thermal unit as an existing resource in this analysis. Currant Creek will provide 280 MW of Simple Cycle Combustion Turbine (SCCT) capacity beginning in June 2005 that is converted to 525 MW of CCCT and duct firing capacity on line in 2006.

Exhibit UP&L___(RW-1) shows that currently the Short-Run period extends through June 2007 and the Long-Run period begins in July 2007. As the method is applied over time, updated load and resource information will be used as in Exhibit UP&L___(RW-1) to update the Short-Run/ Long-Run delineation.

Q. Please describe the Company's calculation of short-run avoided costs.

A. During the Short-Run period from 2004 through June 2007, the Company's avoided energy costs are based on the displacement of power purchased from the wholesale market and power producible by PacifiCorp's owned generation resource fleet as modeled by the

Company's GRID model. GRID model input data includes the hourly load and resource data, which are the basis for the annual summary of loads and resources shown in Exhibit UP&L___(RW-1).

To calculate short-term avoided energy costs, two production cost studies are prepared using GRID. The only difference between the two studies is the inclusion of a 10 MW zero running cost resource in the existing resource stack. This resource serves as a proxy for qualifying facility generation. The resulting difference in system production costs between the two studies represents the Company's avoided energy costs. The avoided energy costs can be thought of as the highest variable cost incurred to serve total system load from existing and non-deferrable resources. As avoided costs are updated through time, new GRID studies will be prepared based on then-current data.

Summer capacity costs in the Short-Run period are based on three-month capacity purchases and are presented in column (b) of the Avoided Resource panel on page 2 of Exhibit UP&L___(RW-1). Since the purchases would be for only one-fourth of the year, the annual value is one-fourth of the capacity cost of a simple cycle combustion turbine (SCCT).

Q. Please describe the assumed 10 MWa zero running cost resource in terms of location and production characteristics.

A. The 10 MW zero running cost resource serves as a surrogate for QF generation. It is located in Utah, and is assumed to operate at a 100 percent capacity factor.

Q. What is shown in Exhibit UP&L___(RW-2)?

A. Exhibit UP&L___(RW-2) summarizes the calculation of Short-Run avoided costs based on current information.

Q. Please describe the Company's calculation of long-run avoided costs.

A. During the Long-Run period beginning July 2007, the period during which new resource additions will be required, avoided costs are based on the fixed and variable costs of the planned resource which could be avoided or deferred. For the purposes of this analysis, the Company uses a combined cycle combustion turbine (CCCT) as a proxy for future resource costs.

The operational and cost characteristics of CCCTs represent a highly efficient unit that provides both capacity and energy. Thus, it is appropriate to split the fixed costs of this unit into capacity and energy components. The fixed cost of the less efficient SCCT, which is usually acquired when initial capital cost is a primary factor or when other constraints (such as when shorter construction times are required) defines the portion of the fixed cost of the CCCT that is assigned to capacity. Fixed costs associated with the construction of a CCCT which are in excess of SCCT costs, i.e., those associated with adding the steam cycle and duct firing, are classified as energy in the form of capitalized energy costs, and are added to the variable production (fuel) cost of the CCCT to determine the total avoided energy costs. Pages 1, 2, 3 and 4 in Exhibit UP&L___(RW-3) show these calculations based on current information. As avoided cost is updated through time, the input data in Exhibit UP&L___(RW-3) will be updated to reflect then-current information.

Q. Why is the proposed method the Company's preferred method of calculating avoided cost prices?

A. The major reason is that the method produces avoided cost rates that meet PURPA's ratepayer indifference standard by reflecting the costs the Company can actually avoid, based on its existing resources and requirements, and its least-cost resource options, with purchases from QFs. It also appropriately reflects the method requested by the Commission to develop published avoided cost rates.

The method recognizes that in the short run, during a period of energy and winter capacity sufficiency, purchases from QFs would only allow the Company to avoid the incremental cost of energy production from the existing power supply resource portfolio and the cost of a summer capacity purchase. Therefore, the energy component of the Company's Short-Run avoided costs is properly reflected as the incremental cost of energy production from the existing portfolio and the capacity component of the Company's short term avoided cost is reflected by a three month summer capacity purchase.

In the Long Run, when the Company requires additional energy and capacity resources in both the summer and winter, the method recognizes that the Company can avoid the fixed costs of a highly efficient unit. Since a CCCT is the Company's current view of its least-cost resource option, the Company's long-run avoided costs are based on the fixed and variable costs of a CCCT. This is consistent with the Company's IRP action plan. The Company believes the cost of the CCCT is also representative of the cost of future resources.

Q. Does the proposed method have other attributes which are desirable for an avoided cost methodology?

A. Yes. The proposed method is consistent with methodologies authorized in the Company's other jurisdictions and is easily updated, simple to use, and easy to understand. The Company believes these are desirable attributes for an avoided cost methodology, because they will allow the Company, potential developers, and the Commission to more effectively evaluate potential QF projects in a timely and cost effective manner and arrive at avoided costs that are proper and protect customers under PURPA's ratepayer indifference standard.

Q. How does the method you propose relate to the method used to produce the avoided cost filing made by the Company on January 29, 2004 in Docket No. 03-035-T10?

A. The January 29 filing was made using the method I propose here. The data in my exhibits is taken from that filing.

Q. Does this conclude your testimony?

A. Yes.

PacifiCorp
Exhibit UP&L___(RW-1)
Docket No. 03-035-14
Witness: Rodger Weaver

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

PACIFICORP

Exhibit Accompanying Direct Testimony of Rodger Weaver
Load and Resources

February 2004

Load and Resources
Avoided Cost Study January 2004

	2004	2005	2006	2007[1]	2008
Peak (August)					
Net Load	8,214	8,682	8,870	9,156	9,482
Special Sales	2,308	1,112	983	546	511
Total Requirements	10,522	9,794	9,853	9,702	9,993
Purchases	3,996	2,638	1,622	1,053	954
Thermal Generation	6,290	6,548	6,789	6,565	6,565
Other Generation	574	574	652	652	649
Reserves	(643)	(661)	(681)	(666)	(666)
Total Resources	10,217	9,100	8,381	7,605	7,503
Surplus / (Deficit)	(305)	(694)	(1,472)	(2,097)	(2,490)
Percent Surplus / (Deficit)	(2.9%)	(7.1%)	(14.9%)	(21.6%)	(24.9%)
Peak (January)					
Net Load	7,586	7,925	8,010	8,202	8,398
Special Sales	2,469	1,087	859	486	459
Total Requirements	10,055	9,012	8,869	8,688	8,857
Purchases	3,972	2,946	2,489	2,374	1,938
Thermal Generation	6,290	6,290	6,548	6,565	6,565
Other Generation	845	844	959	962	966
Reserves	(656)	(655)	(679)	(681)	(681)
Total Resources	10,452	9,424	9,317	9,221	8,787
Surplus / (Deficit)	397	412	448	533	(69)
Percent Surplus / (Deficit)	4.0%	4.6%	5.0%	6.1%	(0.8%)
aMW					
Net Load	6,131	6,369	6,491	6,645	6,803
Special Sales	1,802	979	609	365	331
Total Requirements	7,933	7,348	7,100	7,010	7,135
Purchases	2,120	1,521	1,311	1,053	710
Thermal Generation	5,912	5,983	6,229	6,187	6,188
Other Generation	585	586	586	586	585
Reserves	(618)	(623)	(640)	(637)	(637)
Total Resources	7,999	7,467	7,486	7,190	6,845
Surplus / (Deficit)	66	119	386	180	(289)
Percent Surplus / (Deficit)	0.8%	1.6%	5.4%	2.6%	(4.1%)

(1) The deficit period starts June 2007

PacifiCorp
Exhibit UP&L___(RW-2)
Docket No. 03-035-14
Witness: Rodger Weaver

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

PACIFICORP

Exhibit Accompanying Direct Testimony of Rodger Weaver
Avoided Energy Costs

February 2004

Avoided Energy Costs
Avoided Resource (2004 through June 2007)
Combined Cycle CT (July 2007 through 2008)
$/MWH

Year	Winter Season				Summer Season						Winter Season	
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
On-Peak												
2004	$39.80	$37.26	$35.45	$30.66	$26.45	$25.24	$43.07	$42.32	$30.18	$31.52	$37.31	$40.61
2005	$43.73	$41.92	$38.99	$35.30	$32.00	$40.84	$98.35	$64.66	$37.35	$35.02	$38.69	$41.98
2006	$44.11	$43.10	$40.27	$36.79	$33.83	$32.93	$85.51	$68.48	$36.50	$29.34	$33.14	$39.25
2007 (1)	$43.62	$42.24	$38.70	$35.01	$33.44	$54.06	$54.80	$54.80	$54.80	$54.80	$54.80	$54.80
2008	$54.89	$54.89	$54.89	$54.89	$54.89	$54.89	$54.89	$54.89	$54.89	$54.89	$54.89	$54.89
Off-Peak												
2004	$36.01	$33.47	$31.66	$26.87	$22.67	$21.45	$39.29	$38.53	$26.39	$27.74	$33.52	$36.83
2005	$39.85	$38.04	$35.11	$31.42	$28.12	$36.96	$94.47	$60.78	$33.47	$31.14	$34.81	$38.10
2006	$40.14	$39.13	$36.29	$32.82	$29.85	$28.95	$81.54	$64.50	$32.53	$25.36	$29.16	$35.27
2007 (1)	$39.54	$38.17	$34.62	$30.93	$29.37	$49.98	$34.30	$34.30	$34.30	$34.30	$34.30	$34.30
2008	$33.88	$33.88	$33.88	$33.88	$33.88	$33.88	$33.88	$33.88	$33.88	$33.88	$33.88	$33.88
Combined												
2004	$38.17	$35.63	$33.82	$29.03	$24.83	$23.61	$41.44	$40.69	$28.55	$29.89	$35.68	$38.98
2005	$42.06	$40.25	$37.32	$33.63	$30.33	$39.17	$96.68	$62.99	$35.68	$33.35	$37.02	$40.32
2006	$42.40	$41.39	$38.56	$35.08	$32.12	$31.22	$83.80	$66.77	$34.79	$27.63	$31.43	$37.53
2007 (1)	$41.86	$40.49	$36.95	$33.25	$31.69	$52.31	$45.99	$45.99	$45.99	$45.99	$45.99	$45.99
2008	$45.86	$45.86	$45.86	$45.86	$45.86	$45.86	$45.86	$45.86	$45.86	$45.86	$45.86	$45.86

Annual Seasonal Average

	Winter Season			Summer Season		
	On-Peak	Off-Peak	Combined	On-Peak	Off-Peak	Combined
2004	$36.85	$33.06	$35.22	$33.13	$29.34	$31.50
2005	$40.10	$36.22	$38.43	$51.37	$47.49	$49.70
2006	$39.44	$35.47	$37.73	$47.77	$43.79	$46.06
2007 (1)	$44.86	$35.31	$40.75	$51.12	$36.09	$44.66
2008	$54.89	$33.88	$45.86	$54.89	$33.88	$45.86

Annual Average

	On-Peak	Off-Peak	Combined
2004	$34.99	$31.20	$33.36
2005	$45.74	$41.85	$44.07
2006	$43.61	$39.63	$41.89
2007 (1)	$47.99	$35.70	$42.71
2008	$54.89	$33.88	$45.86

Source Official Price Forecast - Quoted December 31, 2003
CCCT Avoided Costs: Table 6 - Combined costs are 57% On-Peak 43% Off-Peak

(1) 2007 costs are based on 6 months of an Avoided Resource (January - June) and 6 months of a CCCT (July - December)

PacifiCorp
Exhibit UP&L___(RW-3)
Docket No. 03-035-14
Witness: Rodger Weaver

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

PACIFICORP

Exhibit Accompanying Direct Testimony of Rodger Weaver
Capitalized Energy Costs

February 2004

Capitalized Energy Costs

Year	Combined Cycle CT Fixed Costs ($/kW-yr)	Simple Cycle CT Fixed Costs ($/kW-yr)	Capitalized Energy Costs ($/kW-yr)	Capitalized Energy Costs 85% CF ($/MWH)
	(a)	(b)	(c)	(d)
			(a) - (b)	(c)/(8.76*0.85)
Avoided Resource				
2004		$16.07 (2)		
2005		$16.47		
2006		$16.88		
2007 (1)		$17.30		
Combined Cycle				
2007 (1)	$94.90	$86.99	$7.91	$1.06
2008	$97.27	$89.17	$8.10	$1.09
2009	$99.70	$91.40	$8.31	$1.12
2010	$102.20	$93.68	$8.51	$1.14
2011	$104.75	$96.02	$8.73	$1.17
2012	$107.37	$98.42	$8.95	$1.20
2013	$110.05	$100.89	$9.17	$1.23
2014	$112.81	$103.41	$9.40	$1.26
2015	$115.63	$105.99	$9.63	$1.29
2016	$118.52	$108.64	$9.87	$1.33
2017	$121.48	$111.36	$10.12	$1.36
2018	$124.52	$114.14	$10.37	$1.39
2019	$127.63	$117.00	$10.63	$1.43
2020	$130.82	$119.92	$10.90	$1.46
2021	$134.09	$122.92	$11.17	$1.50
2022	$137.44	$125.99	$11.45	$1.54
2023	$140.88	$129.14	$11.74	$1.58
2024	$144.40	$132.37	$12.03	$1.62
2025	$148.01	$135.68	$12.33	$1.66
2026	$151.71	$139.07	$12.64	$1.70
2027	$155.50	$142.55	$12.96	$1.74
2028	$159.39	$146.11	$13.28	$1.78

Columns
- (a) Table 8 Column (f)
- (b) Table 8 Column (f)

(1) 2007 costs are based on 6 months of an Avoided Resource (January - June) and 6 months of a CCCT (July - December)

(2) Capacity payments are for a three month summer capacity purchase June through August (Table 8 Column (f) / (3/12)). Capacity Payments are based on the fixed costs of a SCCT excluding transmission upgrades

Total Avoided Energy Cost

Year	Combined Cycle Gas Price ($/MMBtu)	Combined Cycle Energy Cost ($/MWH)	Capitalized Energy Costs 85% CF ($/MWH)	Total Avoided Energy Cost ($/MWH)
	(a)	(b)	(c)	(d)
				(b) + (c)
Avoided Resource				
2004				$31.20
2005				$41.85
2006				$39.63
2007 (1)				$37.10
Combined Cycle		(a) x 7.623		
2007 (1)	$4.36	$33.24	$1.06	$34.30
2008	$4.30	$32.79	$1.09	$33.88
2009	$4.27	$32.58	$1.12	$33.69
2010	$4.09	$31.18	$1.14	$32.32
2011	$4.09	$31.18	$1.17	$32.35
2012	$4.17	$31.81	$1.20	$33.01
2013	$4.26	$32.47	$1.23	$33.70
2014	$4.34	$33.10	$1.26	$34.36
2015	$4.45	$33.91	$1.29	$35.20
2016	$4.58	$34.94	$1.33	$36.26
2017	$4.71	$35.88	$1.36	$37.24
2018	$4.84	$36.88	$1.39	$38.28
2019	$4.97	$37.91	$1.43	$39.34
2020	$5.12	$39.06	$1.46	$40.53
2021	$5.27	$40.20	$1.50	$41.71
2022	$5.43	$41.35	$1.54	$42.89
2023	$5.57	$42.49	$1.58	$44.07
2024	$5.74	$43.73	$1.62	$45.35
2025	$5.91	$45.05	$1.66	$46.71
2026	$6.08	$46.32	$1.70	$48.01
2027	$6.25	$47.61	$1.74	$49.35
2028	$6.45	$49.17	$1.78	$50.95

Columns

(a) Table 9 Column (d)
(c) Column (d)
(d) For 2004-2007

(1) 2007 costs are based on 6 months of an Avoided Resource (January - June) and 6 months of a CCCT (July - December)

Total Avoided Cost

Year	Avoided Firm Capacity Costs	Total Avoided Energy Cost	Total Avoided Costs At Stated Capacity Factor		
			75%	85%	95%
	($/kW-yr)	($/MWH)	($/MWH)	($/MWH)	($/MWH)
	(a)	(b)	(c)	(d)	(e)
			(b)+((a)/8.76 x 0.75)	(b)+((a)/8.76 x 0.85)	(b)+((a)/8.76 x 0.95)
Avoided Resource					
2004	$16.07	$31.20	$33.65	$33.36	$33.13
2005	$16.47	$41.85	$44.36	$44.07	$43.83
2006	$16.88	$39.63	$42.20	$41.89	$41.66
2007 (1)	$17.30	$37.10	$39.74	$39.43	$39.18
Combined Cycle					
2007 (1)	$86.99	$34.30	$47.54	$45.99	$44.76
2008	$89.17	$33.88	$47.45	$45.86	$44.60
2009	$91.40	$33.69	$47.61	$45.97	$44.68
2010	$93.68	$32.32	$46.58	$44.90	$43.58
2011	$96.02	$32.35	$46.97	$45.25	$43.89
2012	$98.42	$33.01	$48.00	$46.23	$44.84
2013	$100.89	$33.70	$49.05	$47.25	$45.82
2014	$103.41	$34.36	$50.10	$48.25	$46.78
2015	$105.99	$35.20	$51.34	$49.44	$47.94
2016	$108.64	$36.26	$52.80	$50.86	$49.32
2017	$111.36	$37.24	$54.19	$52.19	$50.62
2018	$114.14	$38.28	$55.65	$53.61	$51.99
2019	$117.00	$39.34	$57.15	$55.05	$53.40
2020	$119.92	$40.53	$58.78	$56.63	$54.94
2021	$122.92	$41.71	$60.41	$58.21	$56.48
2022	$125.99	$42.89	$62.07	$59.81	$58.03
2023	$129.14	$44.07	$63.72	$61.41	$59.59
2024	$132.37	$45.35	$65.49	$63.12	$61.25
2025	$135.68	$46.71	$67.36	$64.93	$63.01
2026	$139.07	$48.01	$69.18	$66.69	$64.72
2027	$142.55	$49.35	$71.05	$68.50	$66.48
2028	$146.11	$50.95	$73.19	$70.57	$68.51

Columns
- (a) Column (b)
- (b) Column (d)

(1) 2007 costs are based on 6 months of an Avoided Resource (January - June) and 6 months of a CCCT (July - December)

On- & Off- Peak Energy Prices

Year	Avoided Firm Capacity Costs	Total Avoided Energy Cost	Capacity Cost Allocated to On-Peak Hours	On-Peak 4,993 Hours	Off-Peak 3,767 Hours
	($/kW-yr)	($/MWH)	($/MWH)	($/MWH)	($/MWH)
	(a)	(b)	(c)	(d)	(e)
			(a) /(8.76 x 85% x 57%)	(b) + (c)	(b)
Avoided Resource					
2004	$16.07	$31.20	$3.79	$34.99	$31.20
2005	$16.47	$41.85	$3.88	$45.74	$41.85
2006	$16.88	$39.63	$3.98	$43.61	$39.63
2007 (1)	$17.30	$37.10	$4.08	$41.18	$37.10
Combined Cycle					
2007 (1)	$86.99	$34.30	$20.50	$54.80	$34.30
2008	$89.17	$33.88	$21.01	$54.89	$33.88
2009	$91.40	$33.69	$21.53	$55.23	$33.69
2010	$93.68	$32.32	$22.07	$54.40	$32.32
2011	$96.02	$32.35	$22.62	$54.97	$32.35
2012	$98.42	$33.01	$23.19	$56.21	$33.01
2013	$100.89	$33.70	$23.77	$57.47	$33.70
2014	$103.41	$34.36	$24.36	$58.72	$34.36
2015	$105.99	$35.20	$24.97	$60.18	$35.20
2016	$108.64	$36.26	$25.60	$61.86	$36.26
2017	$111.36	$37.24	$26.24	$63.48	$37.24
2018	$114.14	$38.28	$26.89	$65.17	$38.28
2019	$117.00	$39.34	$27.57	$66.91	$39.34
2020	$119.92	$40.53	$28.26	$68.78	$40.53
2021	$122.92	$41.71	$28.96	$70.67	$41.71
2022	$125.99	$42.89	$29.69	$72.58	$42.89
2023	$129.14	$44.07	$30.43	$74.50	$44.07
2024	$132.37	$45.35	$31.19	$76.53	$45.35
2025	$135.68	$46.71	$31.97	$78.68	$46.71
2026	$139.07	$48.01	$32.77	$80.78	$48.01
2027	$142.55	$49.35	$33.59	$82.94	$49.35
2028	$146.11	$50.95	$34.43	$85.38	$50.95

Columns
- (a) Column (b)
- (b) Column (d)

(1) 2007 costs are based on 6 months of an Avoided Resource (January - June) and 6 months of a CCCT (July - December)

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF THE APPLICATION OF PACIFICORP FOR AN ORDER APPROVING AVOIDED COST RATES	))))))	Docket No. 03-035-14 DIRECT TESTIMONY OF BRUCE W. GRISWOLD

FEBRUARY 2004

Q. Please state your name, business address and position with PacifiCorp dba Utah Power & Light Company (the Company).

A. My name is Bruce W. Griswold. My business address is 825 N. E. Multnomah, Suite 600, Portland, Oregon 97232. I am a Manager in the Origination section of the Company's Commercial and Trading Department.

Qualifications

Q. Please briefly describe your education and business experience.

A. I have a B.S. and M.S. degree in Agricultural Engineering from Montana State and Oregon State, respectively. I have been employed with PacifiCorp over eighteen years in various positions of responsibility in retail energy services, engineering, marketing and wholesale energy services. I have also worked in private industry and with an environmental firm as a project engineer. I currently work in the Commercial and Trading Business unit of PacifiCorp. My responsibilities are wholesale and large retail transactions including the negotiation and management of the non-tariff power supply and resource acquisition agreements with PacifiCorp's largest retail customers.

Q. Have you previously appeared in any regulatory proceedings?

A. Yes. I have appeared in proceedings in Utah and Idaho.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. I will discuss the way the standard avoided cost prices discussed by Dr. Weaver are utilized in the calculation of avoided costs prices for individual qualifying facilities ("QFs") over one megawatt. My primary focus is to identify some of the factors used to determine the components and structure of avoided cost prices for individual QF projects and to explain how these factors are applied. I will also identify some of the factors which should be reflected in power purchase agreements with large QFs.

Q. What factors are considered in determining the avoided cost price paid to an individual QF project?

A. As Dr. Weaver notes in his direct testimony, there are two steps required to determine avoided cost prices for large QFs. The first step is to determine the Company's standard avoided costs. These standard avoided cost prices assume that a QF will have optimum operating characteristics and will impose no additional integration costs on the Company's system above that of system interconnection. The second step is to identify, pursuant to PURPA, the level of costs the large QF actually allows the Company to avoid. PURPA identifies a number of factors that affect rates for purchases from QFs, including:

a. *The type of power being delivered to the utility by the QF project.* One of the key factors affecting the prices paid to the QF is the type of power delivered to PacifiCorp. Rates for purchases should reflect the duration and firmness of the energy and capacity provided. When the QF has contractually committed to make capacity and energy available on a firm basis, the QF is entitled to capacity and energy payments that reflect the energy and capacity costs it allows the Company to avoid. If the QF will only agree to make power available on a non-firm basis, it is entitled to only an energy payment. This means, in instances where the QF decides when the Company is to receive energy, the Company is unable to count on the QF for planning purposes. As a result, the QF should not be entitled to capacity payments for any period and the energy payments during the sufficiency period should be discounted (by 7 percent) to reflect the value of capacity embedded in market prices. This 7 percent discount is a based on the WECC Minimum Operating Reliability Criteria ("MORC") standard for operating reserves and is intended to reflect the cost of the operating reserves that the source control area must carry when making firm market sales. Since the QF is not providing operating reserves as part of its sale to the Company, the Company should discount the energy price by that amount.

b. *The QF's availability during daily and seasonal peak periods.* The Company's standard avoided cost prices assume that energy and capacity from a QF will be available during the Company's daily and seasonal peak periods. If the large QF cannot, or will not commit to provide energy and capacity during peak periods, then no capacity payments should be made to the QF project for those months when the QF is not providing capacity and energy during the peak periods.

c. *The ability of the utility to dispatch the QF.* The ability of a utility to dispatch QF generation on demand (as the proxy resources described in Dr. Weaver's testimony would allow the utility to do) is a key consideration that should be taken into account when establishing avoided costs. Any QF that offers to sell PacifiCorp capacity and energy with a dispatch ability which is lower than the proxy should have a decreased capacity payment, with the converse applying if the dispatch ability is higher than the proxy provides. The methodology for determining this adjustment should be based on the difference between the expected monthly capacity factor of the QF and the proxy unit. Under this method, the QF would submit a schedule of expected monthly capacity factors for each month of the term. A straight-line adjustment would be calculated as the ratio of the QF's expected monthly capacity factor to the proxy's 85 percent capacity factor, multiplied by the capacity payment. A QF's adherence to its proposed availability would be based on actual measured output of the QF each month and the power purchase agreement would include terms for non-performance. Since this analysis is resource specific, it would be applied on a case by case basis.

d. *The reliability of the QF.* The specific rates paid to the QF should be adjusted to reflect the actual, or valid operator estimate, of the facility's operating reliability and capacity production capability, including its heat rate or capacity degradation over time, as compared to the proxy resource. This adjustment is an adjustment to the standard avoided cost capacity payment because it affects the extent to which PacifiCorp can rely on the QF resource for planning purposes. This straight-line adjustment is included in item c above in the calculation of the adjustment for the monthly availability.

Q. Are there additional factors that should be considered in determining avoided cost prices for a large QF?

A. Yes. As Mr. Mendez and Mr. Williams explain, there are accounting standards that should be considered in determining the avoided cost price for an individual QF. Since these debt calculations must be done on an agreement by agreement basis, it is appropriate for the debt-related cost to be addressed as a defined term in the power purchase agreement that should be applied as a monthly line-item adjustment to the QF monthly payment.

Q. Would you address some of the contractual issues that should be considered in the contract with a large QF?

A. Yes. As the PURPA regulations note, there are a number of issues that affect the overall payment for purchases from QFs that are reflected in the non-price provisions of the contract with the QF. A QF contract should contain other cost adjustments to address the contractual arrangement between PacifiCorp and the QF project. These adjustments are mainly for non-compliance, credit requirements, and performance variance. PacifiCorp feels that these issues are adequately captured in the base power purchase agreement template that the Company utilizes for QF agreements.

Q. Can the type of generation technology and fuel source affect the avoided cost price for a large QF?

A. Yes. For example, the avoided cost price for a wind QF project should reflect any costs required for the integration of the resource into PacifiCorp's electrical system because of its intermittent nature and PURPA's requirement to maintain ratepayer neutrality.

Q. What type of integration cost should be ascribed to a QF wind purchase?

A. As noted in PacifiCorp's Integrated Resource Plan ("IRP"), PacifiCorp will have increased operating reserve requirements for wind QF projects and also incur costs for system imbalance because of the intermittent delivery of the wind generation. The amount of those costs should be determined by the results of the most recent IRP and would include, among other adjustments that may be deemed appropriate by the IRP, an adjustment to the avoided cost price paid due to incremental reserve and imbalance costs.

Q. Should a wind QF be paid based on a capacity and energy payment basis or on a volumetric only basis?

A. It is industry practice for wind purchases to be made on a purely volumetric pricing basis (i.e., the buyer pays a $/MWh price only and not does not make fixed monthly capacity payments). This industry practice illustrates the unique nature of wind resources and, therefore, leads to the conclusion that avoided costs for intermittent resources requires an additional pricing step.

Q. How should the avoided cost for an intermittent resource such as wind QF be determined?

A. First, it is appropriate to re-combine the capacity and energy prices determined by the proxy resources using a specified capacity factor. The IRP projected the cost of incremental reserves and imbalance costs associated with wind by comparing wind resources against a firm contract delivery at constant rates over time (i.e, deliveries at a 100 percent capacity factor). Therefore, the appropriate capacity factor to use in re-combining the proxy capacity and energy prices is 100 percent. However, since the proxy resource during the sufficiency period uses the avoidance of firm market purchases to establish the energy price, the energy price during the sufficiency period should be discounted by 7 percent to reflect the value of operating reserves embedded in market prices. This adjustment for operating reserves would only apply during the sufficiency period since market prices are not utilized during the deficiency period. Finally, the incremental reserves and imbalance costs identified by the IRP should be deducted. In PacifiCorp's most recent IRP, the costs associated with incremental reserves and imbalance costs amounted to $5.50 per MWh escalating at inflation.

Q. Are there any other adjustments that should be made to the resulting avoided cost for a wind QF?

A. Yes. If the Commission determines that the renewable energy credits ("green tags") associated with renewable QF resources such as wind should belong to customers then there should be an adjustment for the value of those green tags. The IRP used a green tag value for wind resources of $5 per MWh for the first five-years. If the Commission determines that the green tags inherent in such resources should remain with the QF owner then no such adjustment would be warranted.

Q. Should green tags associated with other renewable QF resources be considered?

A. Yes. The green tags associated with other renewable resources, such as geothermal, should also be considered. However, PacifiCorp's experience has been that green tags from these types of resources have lower avoided costs. In the event the Commission determines that the customer should always receive the green tags associated with renewable QF resources, then the Company should supply the Commission with an update to its view of green tag avoided costs at such time as avoided costs are filed with the Commission.

Q. What type of QF resources are renewable resources?

A. The Company considers renewable resources to be electricity generation facilities fueled by wind, waste, solar or geothermal power or by low-emission non-toxic biomass based on solid organic fuels from wood, forest, and field residues; dedicated energy crops available on a renewable basis; landfill gas and digester gas and hydroelectric facilities located outside protected areas as defined by federal law in effect on July 23, 1999.

Q. Does PURPA allow for the distinction between existing and new QF generation?

A. Yes. Consistent with the statutory policy of promoting cogeneration and small power production, PURPA distinguishes between facilities constructed before and after the date of enactment of the statute, November 9, 1978. PURPA requires a utility to purchase new capacity from QFs at the utility's avoided costs. However, as discussed above, the filed and approved avoided costs are the starting point and the specific price components for a QF project are to be determined on an individualized basis after applying the factors discussed above. In contrast to new capacity, PURPA provides that rates for purchases of existing capacity may be less than the utility's avoided costs if the state commission determines that the rates proposed for the existing QF capacity are just and reasonable and sufficient to encourage cogeneration and small power production.

Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF THE APPLICATION OF PACIFICORP FOR AN ORDER APPROVING AVOIDED COST RATES	))))))	Docket No. 03-035-14 DIRECT TESTIMONY OF DAVID J. MENDEZ

FEBRUARY 2004

Q. Please state your name, business address and present position with PacifiCorp.

A. My name is David Mendez. My business address is 825 N.E. Multnomah, Suite 1900, Portland Oregon. I am the Chief Accounting Officer for PacifiCorp.

Qualifications

Q. Please briefly describe your education and business experience.

A. I've been employed by PacifiCorp since October of 2002. Prior to that time, I was employed by PricewaterhouseCoopers as a senior manager in their audit group. I earned my Bachelor of Science degree in business administration with a concentration in accounting at San Jose State University in California.

Q. As Chief Accounting Officer, have you been involved in an analysis of the impact of new accounting standards on PacifiCorp.

A. Yes. In conjunction with our independent external auditors, I have reviewed the impact on PacifiCorp of Emerging Issues Taskforce ("EITF") 01-08, entitled "Determining whether an arrangement contains a lease" and Financial Interpretation No. 46R ("FIN 46R"), "Consolidation of Variable Interest Entities."

Purpose of Testimony

Q. What is the purpose of your testimony?

A. To explain the impact of new standards on PacifiCorp's financial statements as they relate to power purchase agreements with qualifying facilities (QF's) as a result of the recently adopted EITF 01-08 and FIN 46R.

Q. Would you please explain the potential financial statement impacts of the EITF 01-08 and FIN 46R in relation to long-term power purchase agreements with QFs?

A. EITF 01-08 and FIN 46R address an issue commonly known as "off balance sheet financing." The intent of the two standards is to provide better transparency to potential investors, shareholders and bondholders regarding the fixed obligations of an entity for financial reporting purposes. Under EITF 01-08, PacifiCorp is required to review contracts with QFs to determine whether or not they must be analyzed under Financial Accounting Standard 13 ("FAS 13"), Accounting for Leases. If the contract with the QF meets the EITF criteria, then EITF 01-08 potentially requires that the contract be reviewed under the lease accounting rules. If, after reviewing the contract under the FAS 13 rules, it qualifies for capital lease treatment, then PacifiCorp would be required to record the contract as debt on its balance sheet with a corresponding capital lease asset on the balance sheet. When applied to QF's, FIN 46R could require the assets and liabilities of the QF to be consolidated on the books of the power purchaser if it is determined that the power purchaser is the primary beneficiary. The determination of the primary beneficiary is a complex process that takes many factors into account and is, as of yet, untested at PacifiCorp with respect to a new QF agreement. Exhibit UP&L___(DJM-1) illustrates the application of EITF 01-08 and FIN 46R to QF purchase agreements.

Q. What are the EITF 01-08 criteria?

A. When fulfillment of contract with a QF is dependent upon a specific plant and the contract allows the purchaser the ability or right to operate the plant, or the purchaser has control over physical access to the plant, or it is unlikely that other parties will take more than a minor amount of output from the plant, the lease criteria of FAS 13 must be reviewed for applicability. EITF 01-08 does not apply to power purchases where the energy can be supplied from more than one power plant (not unit specific).

Q. What are the FAS 13 capital lease criteria?

A. If a contract meets any one of the following conditions, it is considered a capital lease and a debt obligation is recorded on the purchaser's books:

i. Ownership transfer at the end of term;
ii. Bargain purchase option;
iii. Term greater than 75 percent of the useful plant life; or
iv. Net present value of fixed payments is greater than 90 percent of asset fair value;

The guidance under FAS 13 is mirrored by the FERC equivalent in 18 CFR, Pt. 101, General Instructions, paragraph 19, *Criteria for classifying leases*.

Q. What must be known before FIN 46R or EITF 01-08 can be applied to a QF agreement?

A. The specific terms and conditions of the agreement, as well as information regarding the particular QF project.

Q. Does this conclude your testimony?

A. Yes.

PacifiCorp
Exhibit UP&L___(DJM-1)
Docket No. 03-035-14
Witness: David J. Mendez

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

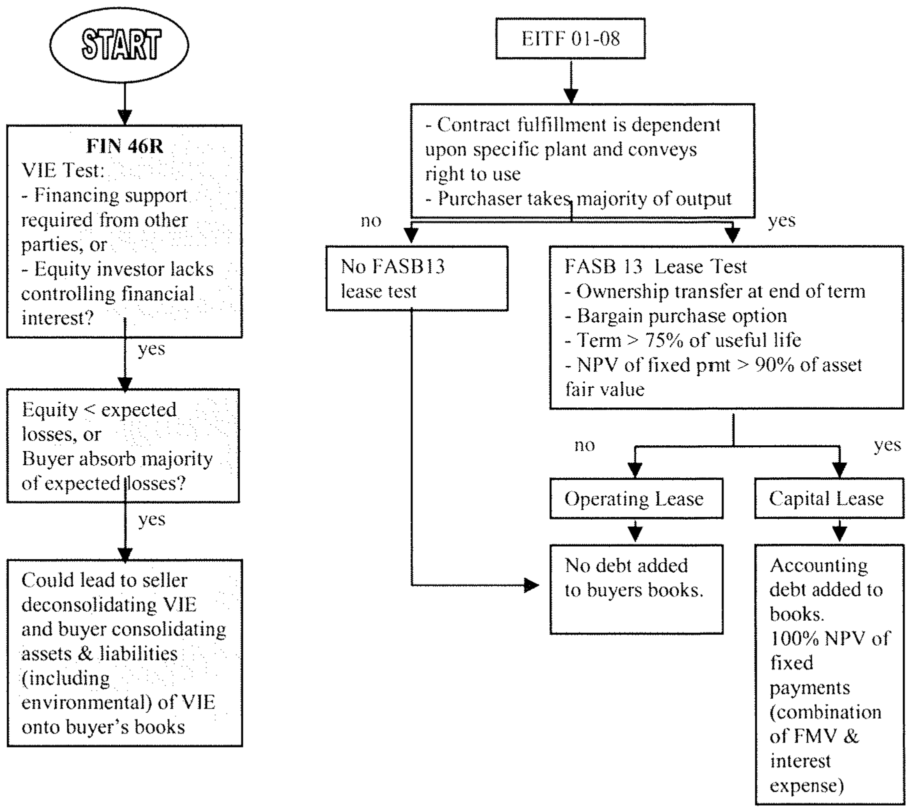
PACIFICORP

Exhibit Accompanying Direct Testimony of David J. Mendez
How PPA Impacts Balance Sheet

February 2004

PacifiCorp
Exhibit UP&L___(DJM-1)
Docket No. 03-035-14
Witness: David J. Mendez

How PPA Impacts Balance Sheet



BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

	)	
IN THE MATTER OF THE	)	Docket No. 03-035-14
APPLICATION OF PACIFICORP	)	
FOR AN ORDER APPROVING	)	DIRECT TESTIMONY
AVOIDED COST RATES	)	OF BRUCE N. WILLIAMS
	)	

FEBRUARY 2004

Q. Please state your name, business address and present position with PacifiCorp.

A. My name is Bruce N. Williams. My business address is 825 N.E. Multnomah, Suite 1900, Portland, Oregon 97232. I am the Treasurer of PacifiCorp.

Qualifications

Q. Please briefly describe your education and business experience.

A. I received a Bachelor of Science degree in Business Administration with a concentration in Finance from Oregon State University in June 1980. I received the Chartered Financial Analyst designation in 1986 after passing the examination. I have been employed by PacifiCorp for 18 years. My business experience has included financing of PacifiCorp's electric operations and non-utility activities, investment management, investor relations and responsibility for non-regulated activities.

Q. Please describe your present duties.

A. I am responsible for the Company's treasury, pension and other investment management and certain non-regulated activities.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. As Mr. Mendez explains in his direct testimony, Emerging Issues Taskforce 01-08 ("EITF 01-08") and Financial Interpretation No. 46R ("FIN 46R") require PacifiCorp to recognize its obligations under certain Qualifying Facility ("QF") contracts as capital lease obligations. Because these QF capital lease obligations are considered to be debt and would be treated like any other debt obligation of the Company, they have impacts on both the Company's financial commitments and credit quality.

My testimony will provide an overview of the way in which PacifiCorp finances its operations and discuss the reasons why the recognition of additional debt associated with purchases from QFs will impose additional costs on the Company and its customers. Mr. Griswold will discuss the Company's proposal regarding how those costs should be recognized in setting prices for purchases from QFs.

Financing Overview

Q. How does PacifiCorp finance its electric utility operations?

A. PacifiCorp requires large amounts of capital to construct and maintain its electrical infrastructure. In order to raise that capital, PacifiCorp relies on a mix of first mortgage bonds, other secured debt, tax exempt debt, unsecured debt, preferred stock and common equity.

Much of the Company's long-term financing is done using secured first mortgage bonds issued under a PacifiCorp Mortgage Indenture dated January 9, 1989. As of December 31, 2003, PacifiCorp had $3,028 million of first mortgage bonds outstanding. In addition, the Company regularly borrows tens of millions of dollars to meet more short term financing requirements.

PacifiCorp has a large capital program that is expected to further increase in order to serve the growing needs of its customers. In order to have access to the capital markets and attract the capital that will be necessary to fund this expansion, PacifiCorp must maintain its credit quality and comply with its financing agreements and other commitments.

Financing Covenants

Q. Do PacifiCorp's financing arrangements impose limitations on its maximum amount of debt?

A. Yes. Many PacifiCorp financing agreements contain financial covenants that the Company must meet to be able to borrow under them. Among the covenants are a maximum debt to total capitalization test and an interest coverage test. These tests are included in PacifiCorp's $800 million of committed bank revolving credit agreements that support short-term debt issuances such as commercial paper. They are also contained in other agreements such as letters of credits and standby bond purchase agreements totaling over $500 million. To the extent that QF contract obligations are treated as debt on the Company's books, they will impact the Company's ability to meet these covenants.

Q. What are the consequences if PacifiCorp exceeds those limitations?

A PacifiCorp would be in default, would have to repay any amounts outstanding and would be unable to borrow under those arrangements. This would likely lead to an inability to pay or roll-over commercial paper as it matures, all resulting in a lack of liquidity for the Company. The likelihood of defaulting on commercial paper and subsequent cross default to other financing obligations would be high. These events would make it very expensive and difficult for PacifiCorp to attract the capital necessary to expand the utility system to meet the growing needs of the customers.

Q. What would PacifiCorp have to do to stay in compliance with these financial covenants?

A. PacifiCorp would likely seek to issue new common equity to its parent company or delay or reduce the capital spending that would otherwise be occurring to meet the growing needs of our customers.

Regulatory Commitments

Q. Does PacifiCorp have other commitments that limit the amount of debt in its capital structure?

A. Yes. For example, PacifiCorp and ScottishPower have made commitments to state utility commissions and the U.S. Securities and Exchange Commission ("SEC") concerning PacifiCorp's minimum level of common equity as a percentage of capitalization. These commitments must be met for PacifiCorp to continue to utilize financing authority from the SEC. To the extent that obligations under QF contracts are treated as debt under accounting standards, it will impact PacifiCorp's ability to meet those tests. Again, this will lead to the likelihood of seeking new common equity or delaying or reducing capital spending programs.

Additional Costs Imposed by QF Contracts

Q. Could the direct recognition of QF obligations as debt on the Company's balance sheet impose additional costs associated with credit quality?

A. Yes. It is important to have a balanced capital structure and additional debt through QF contracts may lead to a need for additional equity to avoid adverse impacts on credit quality. The debt related to a QF power purchase reduces the amount of debt the Company might otherwise issue. There is a cost when the Company's ability to issue debt is reduced. Specifically, because equity is more expensive than debt, the increase in equity required to offset the QF-related debt and allow PacifiCorp to maintain credit quality and compliance with its financing agreements and other commitments would impose additional costs on PacifiCorp and its customers.

Q. Would all QF contracts result in debt being added directly to PacifiCorp's balance sheet?

A. No. The only QF agreements that would result in debt being added directly to PacifiCorp's balance sheet are those agreements where the application of EITF 01-08 or FIN 46R accounting rules would dictate such an application.

Q. If a contract results in debt being added to the Company's balance sheet, yet it does not require the utility to immediately issue equity to balance the capital structure, is there an additional cost?

A. Yes. All QF contracts, whether large or small, that result in debt recognition on the financial statements or by the credit rating agencies diminish the credit capacity of the utility. There is a cost related to the diminished credit capacity.

Q. Can that cost be calculated or observed?

A. Yes. The additional cost associated with a QF contract is equal to the pro-rata share of the cost of diminished credit capacity. The additional cost is the difference between the blended cost of capital and the cost of equity required to balance the capital structure, times the amount of debt that must be recognized due to the QF contract. The size of the additional cost is large or small depending upon the amount of debt that arises as a result of the contract, but it can be significant due to the difference between the blended cost of capital and the cost of equity. PacifiCorp's most recent revenue requirement approved by the Utah Public Service Commission is based on an 8.43 percent return on rate base. This return translates to a 7.14 percent after tax cost of capital, compared to the authorized return on common equity of 10.7 percent.

Q. **Even if a QF obligation is not recognized as debt on PacifiCorp's books, could it adversely impact PacifiCorp's credit quality and result in an additional cost such as that described previously?**

A. Yes. Rating agencies view purchased-power agreements as debt-like in nature. For example, Standard & Poor's will calculate an amount to impute as a debt equivalent related to purchased-power agreements. This amount of debt equivalent is added to a utility's reported debt to calculate adjusted debt. Similarly, Standard & Poor's imputes an associated interest expense related to the debt equivalent which is then added to reported interest expense to calculate adjusted interest coverage ratios. The attached Exhibit UP&L___(BNW-1) details S&P's views on this matter.

Q. **What debt level (accounting-related or rating agency methodology) should be utilized in determining these additional costs?**

A. The debt that should be utilized for determining additional debt-related costs associated with QF agreements should be the higher of: (1) the debt directly added to the Company's balance sheet as a result of applying applicable accounting rules or, (2) the debt determined by the most transparent rating agency methodology.

Q. Which rating agency currently has the most transparent methodology?

A. Standard & Poors.

Q. What risk factor should be applied under the Standard & Poor's methodology to calculate the amount of debt equivalent for QF obligations?

A. Standard & Poor's has stated that a 50 percent risk factor is appropriate for long-term commitments (e.g. terms greater than three years) as a generic guideline for utilities with purchased power agreements. They have stated that further, for utilities in supportive regulatory jurisdictions a risk factor of as low as 30 percent could be used. I believe that a 30 percent risk factor is appropriate in this matter.

Q. Does this conclude your testimony?

A. Yes.

PacifiCorp
Exhibit UP&L___(BNW-1)
Docket No. 03-035-14
Witness: Bruce N. Williams

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

PACIFICORP

Exhibit Accompanying Direct Testimony of Bruce N. Williams
Debt Aspects of Purchased-Power Agreements

February 2004

"Buy Versus Build": Debt Aspects of Purchased-Power Agreements

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Standard & Poor's Ratings Services views electric utility purchased-power agreements (PPA) as debt-like in nature, and has historically capitalized these obligations on a sliding scale known as a "risk spectrum." Standard & Poor's applies a 0% to 100% "risk factor" to the net present value (NPV) of the PPA capacity payments, and designates this amount as the debt equivalent.

While determination of the appropriate risk factor takes several variables into consideration, including the economics of the power and regulatory treatment, the overwhelming factor in selecting a risk factor has been a distinction in the likelihood of payment by the buyer. Specifically, Standard & Poor's has divided the PPA universe into two broad categories: take-or-pay contracts (TOP; hell or high water) and take-and-pay contracts (TAP; performance based). To date, TAP contracts have been treated far more leniently (e.g., a lower risk factor is applied) than TOP contracts since failure of the seller to deliver energy, or perform, results in an attendant reduction in payment by the buyer. Thus, TAP contracts were deemed substantially less debt-like. In fact, the risk factor used for many TAP obligations has been as low as 5% or 10% as opposed to TOPs, which have been typically at least 50%.

Standard & Poor's originally published its purchased-power criteria in 1990, and updated it in 1993. Over the past decade, the industry underwent significant changes related to deregulation and acquired a history with regard to the performance and reliability of third-party generators. In general, independent generation has performed well; the likelihood of nondelivery—and thus release from the payment obligation—is low. As a result, Standard & Poor's believes that the distinction between TOPs and TAPs is minimal, the result being that the risk factor for TAPs will become more stringent. This article reiterates Standard & Poor's views on purchased power as a fixed obligation, how to quantify this risk, and the credit ramifications of purchasing power in light of updated observations.

Why Capitalize PPAs?

Standard & Poor's evaluates the benefits and risks of purchased power by adjusting a purchasing utility's reported financial statements to allow for more meaningful comparisons with utilities that build generation. Utilities that build typically finance construction with a mix of debt and equity. A utility that leases a power plant has entered into a debt transaction for that facility; a capital lease appears on the utility's balance sheet as debt. A PPA is a similar fixed commitment. When a utility enters into a long-term PPA with a fixed-cost component, it takes on financial risk. Furthermore, utilities are typically not financially compensated for the risks they assume in purchasing power, as purchased power is usually recovered dollar-for-dollar as an operating expense.

As electricity deregulation has progressed in some countries, states, and regions, the line has blurred between traditional utilities, vertically integrated utilities, and merchant energy companies, all of which are in the generation business. A common contract that has emerged is the tolling agreement, which gives an energy merchant company the right to purchase power from a specific power plant. *(see "Evaluating Debt Aspects of Power Tolling Agreements," published Aug. 26, 2002)*. The energy merchant, or toller, is typically responsible for procuring and delivering gas to the plant when it wants the plant to generate power. The power plant operator must maintain plant availability and produce electricity at a contractual heat rate. Thus, tolling contracts exhibit characteristics of both PPAs and leases. However, tollers are typically unregulated entities competing in a competitive marketplace. Standard & Poor's has determined that a 70% risk factor should be applied to the NPV of the fixed tolling payments, reflecting its assessment of the risks borne by the toller, which are:

- Fixed payments that cover debt financing of power plant (typically highly leveraged at about 70%),
- Commodity price of inputs,
- Energy sales (price and volume), and
- Counterparty risk.

Determining the Risk Factor for PPAs

Alternatively, most entities entering into long-term PPAs, as an alternative to building and owning power plants, continue to be regulated utilities. Observations over time indicate the high likelihood of performance on TAP commitments and, thus, the high likelihood that utilities must make fixed payments. However, Standard & Poor's believes that vertically integrated, regulated utilities are afforded greater protection in the recovery of PPAs, compared with the recovery of fixed tolling charges by merchant generators. There are two reasons for this. First, tariffs are typically set by regulators to recover costs. Second, most vertically integrated utilities continue to have captive customers and an obligation to serve. At a minimum, purchased power, similar to capital costs and fuel costs, is included in tariffs as a cost of service.

As a generic guideline for utilities with PPAs included as an operating expense in base tariffs, Standard & Poor's believes that a 50% risk factor is appropriate for long-term commitments (e.g. tenors greater than three years). This risk factor assumes adequate regulatory treatment, including recognition of the PPA in tariffs; otherwise a higher risk factor could be adopted to indicate greater risk of recovery. Standard & Poor's will apply a 50% risk factor to the capacity component of both TAP and TOP PPAs. Where the capacity component is not broken out separately, we will assume that 50% of the payment is the capacity payment. Furthermore, Standard & Poor's will take counterparty risk into account when considering the risk factor. If a utility relies on any individual seller for a material portion of its energy needs, the risk of nondelivery will be assessed. To the extent that energy is not delivered, the utility will be exposed to replacing this power, potentially at market rates that could be higher than contracted rates and potentially not recoverable in tariffs.

Standard & Poor's continues to view the recovery of purchased-power costs via a fuel-adjustment clause, as opposed to base tariffs, as a material risk mitigant. A monthly or quarterly adjustment mechanism would ensure dollar-for-dollar recovery of fixed payments without having to receive approval from regulators for changes in fuel costs. This is superior to base tariff treatment, where variations in volume sales could result in under-recovery if demand is sluggish or contracting. For utilities in supportive regulatory jurisdictions with a precedent for timely and full cost recovery of fuel and purchased-power costs, a risk factor of as low as 30% could be used. In certain cases, Standard & Poor's may consider a lower risk factor of 10% to 20% for distribution utilities where recovery of certain costs, including stranded assets, has been legislated. Qualifying facilities that are blessed by overarching federal legislation may also fall into this category. This situation would be more typical of a utility that is transitioning from a vertically integrated to a disaggregated distribution company. Still, it is unlikely that no portion of a PPA would be capitalized (zero risk factor) under any circumstances.

The previous scenarios address how purchased power is quantified for a vertically integrated utility with a bundled tariff. However, as the industry transitions to disaggregation and deregulation, various hybrid models have emerged. For example, a utility can have a deregulated merchant energy subsidiary, which buys power and off-sells it to the regulated utility. The utility in turn passes this power through to customers via a fuel-adjustment mechanism. For the merchant entity, a 70% risk factor would likely be applied to such a TAP or tolling scheme. But for the utility, a 30% risk factor would be used. What would be the appropriate treatment here? In part, the decision would be

Table 1

ABC Utility Co. Adjustment to Capital Structure

	Original capital structure		Adjusted capital structure	
	$	%	$	%
Debt	1,400	54	1,400	48
Adjustment to debt	—	—	327	11
Preferred stock	200	8	200	7
Common equity	1,000	38	1,000	34
Total capitalization	2,600	100	2,927	100

Table 2

ABC Utility Co. Adjustment to Pretax Interest Coverage

	Original capital structure		Adjusted capital structure	
	$	%	$	%
Debt	1,400	54	1,400	48
Adjustment to debt	—	—	327	11
Preferred stock	200	8	200	7
Common equity	1,000	38	1,000	34
Total capitalization	2,600	100	2,927	100

driven by the ratings methodology for the family of companies. Starting from a consolidated perspective, Standard & Poor's would use a 30% risk factor to calculate one debt equivalent on the consolidated balance sheet given that for the consolidated entity the risk of recovery would ultimately be through the utility's tariff. However, if the merchant energy company were deemed noncore and its rating was more a reflection of its stand-alone creditworthiness, Standard & Poor's would impute a debt equivalent using a 70% risk factor to its balance sheet, as well as a 30% risk-adjusted debt equivalent to the utility. Indeed, this is how the purchases would be reflected for both companies if there were no ownership relationship. This example is perhaps overly simplistic because there will be many variations on this theme. However, Standard & Poor's will apply this logic as a starting point, and modify the analysis case-by-case, commensurate with the risk to the various participants.

Adjusting Financial Ratios

Standard & Poor's begins by taking the NPV of the annual capacity payments over the life of the contract. The rationale for not capitalizing the energy component, even though it is also a nondiscretionary fixed payment, is to equate the comparison between utilities that buy versus build—i.e., Standard & Poor's does not capitalize utility fuel contracts. In cases where the capacity and energy components of the fixed payment are not specified, half of the fixed payment is used as a proxy for the capacity payment. The discount rate is 10%. To determine the debt equivalent, the NPV is multiplied by the risk factor. The resulting amount is added to a utility's reported debt to calculate adjusted debt. Similarly, Standard & Poor's imputes an associated interest expense equivalent of 10%—10% of the debt equivalent is added to reported interest expense to calculate adjusted interest coverage ratios. Key ratios affected include debt as a percentage of total capital, funds from operations (FFO) to debt, pretax interest coverage, and FFO interest coverage. Clearly, the higher the risk factor, the greater the effect on adjusted financial ratios. When analyzing forecasts, the NPV of the PPA will typically decrease as the maturity of the contract approaches.

Utility Company Example

To illustrate some of the financial adjustments, consider the simple example of ABC Utility Co. buying power from XYZ Independent Power Co. Under the terms of the contract, annual payments made by ABC Utility start at $90 million in 2003 and rise 5% per year through the contract's expiration in 2023. The NPV of these obligations over the life of the contract discounted at 10% is $1.09 billion. In ABC's case, Standard & Poor's chose a 30% risk factor, which when multiplied by the obligation results in $327 million. Table 1 illustrates the adjustment to ABC's capital structure, where the $327 million debt equivalent is added as debt, causing ABC's total debt to capitalization to rise to 59% from 54% (11 plus 48). Table 2 shows that ABC's pretax interest coverage was 2.6x, without adjusting for off-balance-sheet obligations. To adjust for the XYZ capacity payments, the $327 million debt adjustment is multiplied by a 10% interest rate to arrive at about $33 million. When this amount is added to both the numerator and the denominator, adjusted pretax interest coverage falls to 2.3x.

Credit Implications

The credit implications of the updated criteria are that Standard & Poor's now believes that historical risk factors applied to TAP contracts with favorable recovery mechanisms are insufficient to capture the financial risk of these fixed obligations. Indeed, in many cases where 5% and 10% risk factors were applied, the change in adjusted financial ratios (from unadjusted) was negligible and had no effect on ratings. Standard & Poor's views the high probability of energy delivery and attendant payment warrants recognition of a higher debt equivalent when capitalizing PPAs. Standard & Poor's will attempt to identify utilities that are more vulnerable to modifications in purchased-power adjustments. Utilities can offset these financial adjustments by recognizing purchased power as a debt equivalent, and incorporating more common equity in their capital structures. However, Standard & Poor's is aware that utilities have been reluctant to take this action because many regulators will not recognize the necessity for, and authorize a return on, this additional wedge of common equity. Alternatively, regulators could authorize higher returns on existing common equity or provide an incentive return mechanism for economic purchases. Notwithstanding unsupportive regulators, the burden will still fall on utilities to offset the financial risk associated with purchases by either qualitative or quantitative means.