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UTAH PUBLIC
SERVICE COMMISSION

-BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH-

	)	**Docket No. 94-2035-03**
In the Matter of the Application	)	
of PacifiCorp for an Order	)	Prefiled Direct Testimony
Approving its Avoided Cost Rates	)	of
	)	REBECCA L. WILSON

FILE COPY

PREFILED DIRECT TESTIMONY OF THE UTAH DIVISION OF PUBLIC UTILITIES

November 4, 1994

EXHIBIT NO. DPU-1
Case 94-2035-03
Date 1-23-95
Witness
Reporter

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. Rebecca L.Wilson, 160 East 300 South, Heber M. Wells Building, Salt Lake City, Utah 84145-0807

Q. BY WHOM ARE YOU EMPLOYED?

A. I am employed by the Division of Public Utilities, Utah Department of Commerce.

Q. WHAT IS YOUR POSITION WITH THE DIVISION OF PUBLIC UTILITIES AND WHAT ARE YOUR CURRENT RESPONSIBILITIES?

A. I am a utility economist responsible for providing in-house expertise regarding regulatory economics and for presenting the views of the Division before the Commission on matters related to utility costs and rate design.

Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND?

A. I received a Bachelors degree in Political Science from the University of Utah in 1979 and a Masters degree in Economics from the University of Utah in 1986. My primary fields of study were quantitative methods and applied microeconomics. I worked for the Utah Energy Office from 1979 to 1994, with primary focus on utility issues from 1989 to 1994. I was a senior economist when I departed the Energy Office in 1994, at which time I assumed my present position with the Division of Public Utilities.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My purpose is to address the avoided cost rates filed by PacifiCorp for setting payments to PURPA Qualifying Facilities (QF) with a generating capacity of one megawatt or less. I will present, and provide the analytical support for, the Division's recommendation on methodology for computing avoided energy and capacity costs for qualifying facilities in Utah with a rated capacity of one megawatt or less. I will also present the Division's recommendations regarding the adoption of the standard avoided cost rates proposed by PacifiCorp.

Q. WHAT METHOD SHOULD THE COMMISSION ADOPT FOR COMPUTING AVOIDED ENERGY AND CAPACITY COSTS?

A. I recommend that the adoption of a standard method or methods be deferred until we have an opportunity to review the capability of and results from computing avoided energy and capacity costs using PacifiCorp's integrated resource planning optimization model, called the Integrated Planning Model (IPM), in RAMPP-4, PacifiCorp's Resource and Market Planning Program, which is due to be completed in mid to late 1995.

Q. WHAT STANDARD AVOIDED ENERGY AND CAPACITY COST RATES SHOULD BE ADOPTED AT THIS TIME?

A. I recommend that the Commission approve rates based on PacifiCorp's proposed methods subject to two conditions.

The first condition is that the Commission direct PacifiCorp to compute avoided energy and capacity costs through the expansion plan model IPM in RAMPP-4 and to direct PacifiCorp to refile an application for approval of avoided cost methods and standard QF rates when the IPM avoided cost information is available for analysis.

The second condition is that avoided energy costs computed by PacifiCorp for the period of resource sufficiency which is currently based upon an assumption of 50 MW average of QF power, be recalculated assuming 10 MW as a proxy for the qualifying facilities eligible for payments under the proposed standard rates.

Additionally, I recommend that the standard avoided cost rates approved in this proceeding be presented in a formal tariff and that the rates in the tariff state peak and off-peak prices for summer and winter, and further, that the terms and conditions for payments available under the tariff, i.e., annual or levelized payments, be explicitly stated. I present the following testimony to support these recommendations.

Q. WHAT ISSUES DID YOU CONSIDER IN YOUR ANALYSIS OF PACIFICORP'S PROPOSED AVOIDED COST RATES?

A. Since the issue of methodology has not been addressed in Utah since the Settlement Conference Agreement (SCA) methodology was approved by the Commission in 1987, I focused attention on the theory and methods for estimating avoided cost and evaluated the proposed approach against methods previously adopted by the Utah Commission and other generic methods.

I also reviewed the methods and rates adopted in many of the states PacifiCorp serves in order to assess the extent of consistency with regard to rates available system-wide to small sized qualifying facilities.

Since avoided costs are a function of assumptions regarding future load growth and resource needs, and because the most recently approved avoided cost rates in Utah reflected 1989 load growth and resource addition expectations, I examined the load and resource expectations upon which the proposed rates are based to assure consistency with RAMPP-3, PacifiCorp's most current long-range integrated expansion planning study.

Q. WHAT WAS YOUR PRIMARY CRITERIA FOR EVALUATING AVOIDED COST METHODS?

A. My primary consideration was to assure consistency with prior relevant Utah Commission orders regarding PURPA policy and avoided cost methods. Utah Commission policy is clearly enunciated in the Utah Commission Report and Order Case No. 80-999-06, April 3, 1987, pages 4 and 5, and is worth repeating here:

> "We reiterate our agreement with and commitment to the general goals of PURPA. Specifically, we agree that we should adopt policies and practices which will promote the development of efficient new technologies and put to economic use energy which would otherwise be wasted. The critical concept here is that the specific QF developments which embody the realization of this philosophy must themselves be justified in terms of the costs they impose on the Company's ratepayers. We wish to promote the development of the specific projects and the overall QF capacity which will serve the economic interests of the ratepayers. We wish to discourage QF development which requires a subsidy from the ratepayers to the QF developers. We understand these positions to be the appropriate interpretation of the PURPA full avoided cost based QF pricing and ratepayer neutrality mandates."

The Commission further stated that their policy is to set prices for QF capacity and energy which reflect market conditions...

> "including the value of existing generation capacity surpluses or shortages, and to change these prices as market conditions change. Our intention is that the responses of QF developers to these market signals will serve to keep realized develop-

> ment in line with that level of development which serves the interests of the ratepayers without unduly subsidizing the QF developers."

So essentially, the method should (1) provide an appropriate price signal to encourage the economically efficient amount of QF generation; too low a price will discourage development and require more costly resource acquisitions causing society to forego the benefits of efficient electricity generation; too high a price will encourage QF power beyond its benefits and displace other more economically efficient generation sources causing ratepayers to pay more than is economically optimal; (2) maintain ratepayer neutrality; (3) yield avoided costs which reasonably reflect the value of what is likely to be deferred or avoided and thus reflect full avoided costs; and (4) capture changing market conditions as rates are updated for known and measurable changes in PacifiCorp's system.

Q. WHAT OTHER CRITERIA DID YOU CONSIDER IN EVALUATING AVOIDED COST METHODS?

A. I also considered the size of the qualifying facilities that the rates would apply to in evaluating alternative methods. For example, the SCA method applied to all qualifying facilities and it resulted in a fairly complex but comprehensive approach, i.e., the differential revenue requirements method. Since the method proposed by PacifiCorp only applies to qualifying facilities of one megawatt or less, administrative ease may warrant greater simplicity and transparency than a comprehensive method like SCA. Alternatively, I also considered the fact that although these rates are not explicitly used in other applications, (i.e., negotiations for QF contracts over one megawatt in size, review of resource acquisition decisions, value of demand side resource benefits), in reality, the standard rates are commonly referenced with respect to, or form the basis for, these applications. To the extent that standard avoided cost rates are used for other applications, it is important that the method reflects reality as much as is practicable.

I also considered the consistency of methods and rates adopted in other PacifiCorp jurisdictions since resources are acquired and evaluated with respect to the costs and benefits to the PacifiCorp system rather than individual state jurisdictions.

Q. CAN YOU BRIEFLY DESCRIBE SOME OF THE METHODS YOU REVIEWED FOR ESTIMATING AVOIDED COSTS?

A. Yes. I reviewed (1) long-run marginal cost methods, which can be based on a specific unit approach (like a proxy plant) or an expansion planning approach (which can include a portfolio of resources avoided and integrates demand and supply characteristics); (2) short-run marginal cost methods, which can be based on a single unit approach, or production cost approach; (3) the differential revenue requirements method, which can be based on a production cost approach or expansion planning approach. A

NARUC survey of methods used by states for calculating avoided costs for QFs (Exhibit RLW-1), adds competitive bidding to the list of available methods and indicates that these methods in various versions are the primary methods used by states in determining avoided cost rates for QFs. Although a bidding process has appeal in that it reflects market conditions, it was not considered appropriate for the development of standard rates available to QFs one megawatt or less in size because it would be administratively burdensome if used solely to address smaller units.

Q. HOW DO THESE METHODS COMPARE IN TERMS OF SATISFYING THE CRITERIA NOTED ABOVE?

A. Each method has its strengths and weaknesses with respect to the criteria, i.e., to encourage economic projects, maintain ratepayer neutrality, reflect full avoided costs, and provide a price signal reflective of market conditions for QF power. All methods are subject to error, thus jeopardizing any one of the criteria noted above. One means of comparing the methods is to look at the relative ease and transparency of the method versus achievement of avoided cost rates which satisfy the criteria noted above. At one end of this spectrum is the differential revenue requirements approach which requires substantial system simulation and the estimation of inputs, including financial analysis, and thus is fairly complex in practice but theoretically appealing. At the other end of the spectrum, the long run marginal cost method using a specific plant, a "proxy plant" as proposed by PacifiCorp, is fairly transparent and easy to compute, yet employs simplifying assumptions about resources avoided or deferred.

Q. COULD YOU BRIEFLY DESCRIBE THE DIFFERENTIAL REVENUE REQUIREMENTS METHOD?

A. Yes. The differential revenue requirements approach using an expansion planning model, develops expansion plans both with and without a block of expected QF generation. The two plans are then run through the utility's financial planning model to project revenue requirements with and without the QF generation. The difference in the present value of the resultant revenue requirements provides the basis for QF payments.

Q. COULD YOU DISCUSS THE STRENGTHS AND WEAKNESSES OF THE DIFFERENTIAL REVENUE REQUIREMENTS METHOD?

A. Yes. The National Regulatory Research Institute report, <u>The Appropriateness and Feasibility of Various Methods of Calculating Avoided Costs,</u> states that the differential revenue requirements method "...is based upon the premise that the purchase of power from QFs should not affect the rates paid by other customer classes. Hence, payments to qualifying facilities are based on the avoided revenue requirement made possible by the utility's purchases from qualifying facilities." Thus, this method preserves the goal of ratepayer neutrality. Additionally, to the extent that this method is used in conjunction with a utility's integrated resource expansion plan model, the method matches the QF resource to the energy and capacity costs that will be truly avoided given the utility's planning assumptions, system operating characteristics, load characteristics, load management strategies and consequent dispatch.

This method will yield reasonable and reliable results providing that all assumptions upon which it is based, i.e., the load forecast, expansion plan, load management plans, financial assumptions and estimate of QF development available in a given service territory, reflect reality. Unfortunately, these critical components cannot be forecasted with complete certainty and the degree to which they are in error can result in an inappropriate rate being paid to QFs which jeopardizes the criteria noted above. Further, it may be difficult and cumbersome to discern how sensitive the resultant avoided cost values are to errors in forecasted inputs because of the complexity of the model.

However, the differential revenue requirements approach has several appealing features. It is based upon integrated resource planning and so reflects the value of the delay or displacement of a least cost alternative resource or portfolio of resources which is caused by the availability of a given block of QF power. Avoided costs from alternative RAMPP scenarios could indicate the impact of resource selection on avoided costs, thus possibly assisting in understanding the impact of alternative resource acquisition decisions. The integrated resource planning process undergoes substantial public involvement and analytical scrutiny and thus may increase confidence that the resultant values are not arbitrary. To the extent that RAMPP is understandable and employed to review resource decisions in regulatory proceedings, the Division prefers that the development of avoided cost rates for QF power be estimated through the RAMPP model IPM, either through a sensitivity run or from analysis of the shadow prices produced from the modeled runs. Currently, PacifiCorp uses the differential revenue requirements method for short-run avoided energy costs based on PD-Mac simulation rather than IPM simulation. The IPM model is superior to PD-Mac because it integrates system planning with dispatch and optimizes loads and energy and capacity resources on an hourly basis, whereas PD Mac is a monthly production energy cost dispatching model only.

Additionally, because RAMPP is a biennial process, avoided costs would reflect changes in the market conditions modeled in RAMPP and would be updated every two years.

Q. COULD YOU BRIEFLY DESCRIBE THE "PROXY PLANT" METHOD?

A. Yes. As outlined above, the proxy plant approach is a long run marginal cost method which selects a specific unit to be deferred or avoided. Avoided costs of capacity and energy are based on the projected capacity cost and variable running costs of the selected, future base load unit. Capacity costs are annualized over the life of the unit to yield an annual capacity cost per kW. The variable fuel costs of the proxy plant should be used for avoided energy costs in the long run in order to maintain consistency with the plant delay or deferral concept.

Q. COULD YOU DISCUSS THE STRENGTHS AND WEAKNESSES OF THE "PROXY PLANT" METHOD?

A. The proxy method's greatest feature is with respect to the relative simplicity of acquiring information and making the calculations. Capital cost and operating data is usually available to allow a transparent estimate of the costs avoided for a given facility. However, the method does not capture the impact of the QF's contribution over a utility's demand cycle which may be to displace energy generated by base load, cycling and peaking units at any given point in time. Thus, a one to one correspondence may not exist between QFs and the proxy unit. Further, the total output from QFs may not be sufficient to fully avoid the proxy plant, and thus result in inappropriate prices for the QF power. In reality, the QF generation may defer the plant or cause a change in the mix of new generation options. Since the proxy plant may not be the actual resource deferred or delayed, and since the long run avoided capacity and energy cost rate is based entirely upon this resource assumption, this method can be viewed as arbitrary.

Q. DOES THE DIVISION RECOMMEND RESURRECTING THE SCA METHOD FOR ESTIMATING AVOIDED CAPACITY COSTS?

A. No. The SCA method for computing capacity avoided cost, which is essentially a differential revenue requirements method based on a capacity expansion plan, was specifically designed to model the pre-merged Utah Power system. And though the differential revenue requirements method is appealing, as noted previously, the SCA is outdated in terms of appropriately addressing the current Utah Power system and at this point it would be too cumbersome to revise for application to QFs which have a rated capacity of less than one megawatt. System conditions have substantially changed since the SCA was approved and current analytical tools like PD-Mac, PacifiCorp's production cost and dispatch model, and the RAMPP optimization model, IPM, now model the current PacifiCorp system.

Q. DO YOU RECOMMEND ADOPTING THE "REALIZED MARGINAL COST METHOD" FOR ESTIMATING AVOIDED ENERGY COSTS?

A. No, not at this time. The method is theoretically sound and intuitively appealing because it provides a real-time, dynamic evaluation of avoided costs and thus addresses the criteria that the method be responsive to changing market conditions. However, the Division is currently investigating whether the method as it is currently implemented is appropriately capturing costs avoided by QF generation. The method currently provides payments to a QF based on the highest costs incurred by PacifiCorp in a given hour at the single MW level. The method then calculates avoided energy cost as the average of these hourly costs over a six month period. We are concerned that the single MW assumption overstates the value of accumulated QF power in the PacifiCorp system which currently exceeds one megawatt. Additionally, we are concerned that some of the costs currently included in this analysis, i.e., interruptible buy-through and purchases for resale, are not avoided with the addition of QF power onto the system. If these concerns are correct, the goal of ratepayer neutrality is violated. Consequently, we need to wait until the investigation is completed before recommending the adoption of this method.

Q. GIVEN THE FOREGOING REVIEW OF METHODS, WHAT METHODS DOES THE DIVISION RECOMMEND THE COMMISSION ADOPT AT THIS TIME?

A. We recommend that a decision on the appropriate standard method be deferred until information on the capability IPM to produce avoided energy and capacity costs is available for evaluation and comparison with the methods currently proposed by PacifiCorp. However, we support the development of standard tariff rates using PacifiCorp's proposed proxy/differential revenue requirements hybrid method for both energy and capacity for these smaller projects *at this time* because it is less administratively cumbersome, transparent to QFs, and satisfies FERC regulations which require that standard rates be put into effect for purchases from qualifying facilities with design capacity of 100 kW or less.

Q. WHY DO YOU RECOMMEND THAT THE COMMISSION ADOPT PACIFICORP'S APPLICATION TO SET RATES BASED ON THE USE OF THE PROXY METHOD TO SET LONG-RUN AVOIDED COSTS AND THE DIFFERENTIAL REQUIREMENTS METHOD USING PD-MAC TO SET SHORT-RUN AVOIDED COSTS?

A. For three reasons. First, PacifiCorp's proposal only applies to QFs generating less than one megawatt and we do not expect an error in adoption of problematic rates resulting from a possibly wrong proxy resource to have a material impact on jeopardizing the criteria set out above between now and the completion of RAMPP-4. <u>Additionally, the Division recommends that the Commission direct PacifiCorp to use the RAMPP-4 expansion plan model IPM to generate avoided costs as a reality check on the rates produced using the proposed proxy method.</u> Thus, if rates proposed here are notably different from the RAMPP-4 generated avoided cost rates, we can revisit the issue.

Our second reason is that the proposed method appears to be consistent with methods and rates adopted in several other PacifiCorp states for QFs one to three megawatts in size (Montana's rules apply to QFs three

MW or less) and since PacifiCorp operates as a single system, with new resource costs allocated system wide, we are persuaded to approve these rates at this time for consistency and expediency reasons.

Our third reason is that the proposal is reasonably consistent with RAMPP-3 analysis and therefore provides critical improvement over the previously approved avoided cost rates which are based on RAMPP-1 (1989) load growth and resource addition expectations. Considerable changes have occurred in the system since 1989 and we would like updated values adopted before RAMPP-4 avoided cost analysis is completed. FERC requires that standard rates be available for purchases from QFs 100 kW or less in size, and previously approved rates were suspended and need to be updated and approved.

We also support the development of standard tariff rates using PacifiCorp's proposed proxy/differential revenue requirements hybrid method for both energy and capacity for these smaller projects at this time because it is not administratively cumbersome, and the link between costs avoided and QF power purchase rates is fairly transparent to QFs.

Q. HOW ARE THE METHODS AND RATES PROPOSED CONSISTENT WITH WHAT OTHER STATES HAVE ADOPTED?

A. Montana adopted the proposed methods and rates except that Montana rules require the assumption of 10 MW of QF power in the short run avoided energy cost analysis rather than the 50 MW average assigned by PacifiCorp. The impact of the 10 MW assumption is to raise the avoided energy cost rates slightly as compared to the rates resulting from 50 MW average assumption. Neither PacifiCorp nor Montana provide substantial discussion on the basis for the assumptions. Also, Montana allows QFs up to three MW in size to use the standard rates.

Wyoming adopted PacifiCorp's proposed methods and rates except that the Wyoming tariff restricts the avoided cost rates to the first 10 MW which utilize the tariffed rates.

Oregon essentially adopted the same methods and rates, to be revisited upon "acknowledgment" of RAMPP-3 by the Oregon Commission. This potential revision is important to note because PacifiCorp's proposed rates assume a less than least cost amount of demand side resource acquisition by the Company. Oregon's draft order does not acknowledge this amount. If the Oregon Commission required PacifiCorp to revise its loads to reflect the accelerated amount of DSR, the impact would be to decrease the avoided cost rates currently filed in comparison to values adopted in other states. Of additional note is that the Oregon order adopting these rates explicitly states that the rates will serve as a starting point for negotiations between PacifiCorp and QFs greater than one megawatt.

The only other distinction in Oregon, Wyoming and Montana is that a standard tariff explicitly states the rates on a time and seasonally differentiated basis, and in some cases states the terms and conditions upon which payments could be annual or levelized over period of time. This additional information provides a signal to potential and existing QFs eligible for this rate regarding the value of QF power to the PacifiCorp system. Such information could also be of value for DSR lost revenue assessment. The Division therefore supports the provision of this type of information in tariff format.

Idaho is fairly different all around. Capacity payments must be based upon displacement of a coal fired resource emplaced in Powder River Basin. This probably reduces the value of avoided costs in comparison to analysis assuming a combined cycle combustion turbine. Additionally in Idaho, load and resource balance must be estimated absent demand-side resource contribution to load, thus moving forward capacity requirements and increasing the rates. An avoided cost proceeding is currently underway in Idaho. PacifiCorp is proposing the same methods and rates in that proceeding as they have in this Utah proceeding. All other utilities filing avoided costs in Idaho, are also requesting that a combined cycle combustion turbine replace the required coal plant in the Idaho approved "SAR" methodology, as noted in Dr. Weaver's testimony..

Q. ARE THE INPUTS, METHODS AND RATES PROPOSED CONSISTENT

WITH THE RAMPP-3 REPORT?

A. Yes and no. Load growth is consistent with the RAMPP-3 medium load growth assumption of 2.4% average annual over the next 10 years. Resource acquisitions assumptions are consistent with the RAMPP-3 Action Plan. However, it is debatable whether the Action Plan is consistent with a least cost integrated resource plan. For example, PacifiCorp's proposed proxy resource is a combined cycle combustion turbine which is rarely, if ever, preferred over coal as a least cost base load plant. Additionally, RAMPP selects a greater amount of DSR than the Action Plan. Without acquisition of the Hermiston plant, RAMPP-3 scenarios consistently pick cogeneration on the west side of the system due to the off-peak transmission constraint limiting movement of east side resources to the west side to satisfy BPA energy return in off-peak hours. However, with transmission constraints relaxed, the model would not have needed all the cogeneration on the west side, and would have selected more *coal* on the east side instead of a substantial amount of west side cogeneration. Absent relaxing the transmission constraint, Hermiston satisfies the need for west side cogeneration. The Hermiston sensitivity run in RAMPP-3 which evaluated the impact of the Hermiston acquisition on system costs, resulted in lower costs than the sensitivity which relaxed the transmission constraints. To the extent that the model sensitivities accurately captured the costs and benefits of these two alternatives, including Hermiston in the avoided cost analysis is consistent with RAMPP-3 least cost analysis. With the addition of the Hermiston project, added after RAMPP-3 existing resource assumptions were set, but upon which the proposed avoided cost rates are based, no new resources are required until according to RAMPP-3 until 2001 at which time, if allowed to select coal resources, the model selects coal on the east side. With Hermiston included as an existing system resource, the model calls for new resources in 2001 at which time least internal or private cost is a coal plant on the east side, rather than a combined cycle combustion turbine. However, in the RAMPP-3 Action Plan PacifiCorp is neither committed to nor uncommitted to acquisition of a coal plant in 2001. The combined cycle proxy appears to be the preferred proxy resource as it is the proxy plant adopted by all states in PacifiCorp's service territory that have adopted this method and rates. The movement forward of resource constraint from 2001 in RAMPP-3 to 2000 in this filing, is explained by the known and measurable changes noted in Dr. Weaver's testimony.

Q. WHAT IS THE IMPACT OF THESE NOTED DEVIATIONS FROM LEAST COST?

A. It is likely that the impact of the deviations from least cost by not assuming a coal plant and by acquiring less DSR would be to increase the value of the proposed avoided costs, given that a combined cycle combustion turbine is more costly than a coal plant, absent the cost of environmental consequences, and that less DSR increases supply side resource acquisition.

Q. WHY DO YOU RECOMMEND THAT SHORT-RUN AVOIDED ENERGY COSTS BE BASED ON 10 MW RATHER THAN 50 MW average?

A. The amount of QF generated power under one megawatt assumed in the short run differential revenue requirement calculation of avoided cost is an important assumption. It is intended to reflect the decrement of resources that will be avoided by QFs under one MW in a period of resource sufficiency and should simulate the expected amount of QF activity eligible under this rate. Currently, the total amount of QF power in the PacifiCorp system which utilize the standard tariff rates is just under 10 MW. Exhibit RLW-2 provides a breakdown by state and resource type of these QFs.

Keeping with the goal of promoting efficient new technologies and capturing otherwise wasted energy, and maintaining ratepayer neutrality, we find the assumption of 10 MW more reflective of the decrement of resource that will be avoided than the 50 MW average assumption. The SCA method had assumed a 15 MW annual contribution of QF power but again, this assumption applied to all QF generation not just small units. For consistency with at least one other PacifiCorp state, Montana, we support the 10 MW assumption at this time. This assumption should be revisited to reflect changes in the market.

Another reason to support this recommendation is that It does not seem reasonable to expect that 50 MW average of power generated from QFs under one megawatt will occur in this time horizon. The majority of projects currently being discussed in Utah that I am aware of, are larger scale and therefore not addressed by these proposed rates. Absent information supporting the expectation that 50 MW average of QF generation is an appropriate system-wide amount eligible or likely to be eligible for this tariff over the planning horizon, I can not recommend adoption of this amount as it could discourage economically efficient projects.

Q. COULD YOU PLEASE SUMMARIZE YOUR RECOMMENDATIONS?

A. Yes. I recommend that the rates as proposed by Dr. Weaver be adopted with two conditions: (1) That the short-run avoided energy costs be based on a 10 MW assumption of QF generation during the period of resource sufficiency; and (2) I recommend that the Commission direct PacifiCorp to generate avoided costs using the IPM optimizing model in RAMPP-4. The RAMPP-4 avoided energy and capacity costs should be filed within 60 days of the date the final RAMPP-4 report is filed with the Commission. At that time, we can re-evaluate whether the method proposed in this filing is appropriate for generating avoided energy and capacity costs for standards rates to QFs one megawatt or less in size, or whether the IPM approach is more appropriate.

I further recommend that PacifiCorp propose and present a standard tariff for the avoided energy and capacity cost providing peak and off/peak rates for winter and for summer. Terms and conditions for receiving payments based on annual rates or levelized rates should also be provided. This tariff should be updated for known and measurable changes in concert with the RAMPP cycle.

Q. DOES THIS CONCLUDE YOUR TESTIMONY AT THIS TIME?

A. Yes, it does.

TABLE 190 - CALCULATION OF AVOIDED COSTS TO ESTABLISH RATES FOR PURCHASES FROM QUALIFYING FACILITIES BY ELECTRIC UTILITIES

AGENCY	WHAT METHOD DOES AGENCY USE OR APPROVE TO CALCULATE AVOIDED COSTS USED IN ESTABLISHING RATES FOR PURCHASES FROM QUALIFYING FACILITIES UNDER PURPA	HAS AGENCY APPROVED TARIFFS FOR STANDBY SERVICE WHICH APPLY SPECIFICALLY TO QUALIFYING FACILITIES UNDER PURPA
ALABAMA PSC	Utility estimates costs with production costing model with results approved by the Commission	Yes, applies to all not just QFs
ALASKA PUC	2, 3, 4	Yes
ARIZONA CC	2	Yes
ARKANSAS PSC	4	Yes
CALIFORNIA PUC	1, 4	
COLORADO PUC	2, 5 (based on Regional Power Market Price)	Yes
CONNECTICUT DPUC	Consider 2, 3, 5, life extension, conservation	Yes
DELAWARE PSC	2, 4	Yes
DC PSC	3	Yes
FLORIDA PSC	2, 3, 4	Yes
GEORGIA PSC	No capacity costs. Rates are energy only and are calculated on actual territorial marginal cost.	Yes
HAWAII PUC	2, 3, 4 and intermediate steam units.	
IDAHO PUC	Baseload plant as proxy.	No
ILLINOIS CC	4	Yes
INDIANA URC	1, 2, 3	Yes
IOWA UB	4	Yes
KANSAS SCC	Utility-specific rates are established	No
KENTUCKY PSC	Most companies use the cost differential resulting from a one-year deferral of a planned peaking plant	No
LOUISIANA PSC	Avoided fuel costs	Yes
MAINE PUC	4, 5, differential revenue requirements	No
MARYLAND PSC	2, 3, 4	Yes
MASSACHUSETTS DPU	2	Yes
MICHIGAN PSC	Base load coal plant as proxy	Yes
MINNESOTA PUC	Next proposed capacity addition of whatever kind	Yes, applies to all, not just QFs
MISSISSIPPI PSC	3, 4	Yes
MISSOURI PSC	2, 4	Yes
MONTANA PSC	3, 4, also account for opportunity costs	PPL Dkt 90.11.78, approved 3/4/92 applies to all not just QFs.
NEBRASKA PSC	Does not regulate electric utilities	
NEVADA PSC	1, 3, 4, 5 are all taken into account	Yes
NEW HAMPSHIRE PUC	1, 2	Yes
NEW JERSEY BRC	3, 5	Yes
NEW MEXICO PUC	Energy only; purchased power cost; monthly calculations	Yes
NEW YORK PSC	1, 2, 4, 5	Yes, applies to all, not just QFs
NORTH CAROLINA UC	1, 3, 5	No
NORTH DAKOTA PSC	1, 2, 3, 4	Yes
OHIO PUC	No generic approach established	Yes
OKLAHOMA CC	1, 2	Yes
OREGON PUC	2, 3, 4, 5	No
PENNSYLVANIA PUC	2	Yes
RHODE ISLAND PUC	Market based; utilities calculate their own rate	
SOUTH CAROLINA PSC	1	Yes
SOUTH DAKOTA PUC	Average hourly incremental avoided costs	Yes
TENNESSEE PSC	No method established	No
TEXAS PUC		
UTAH PSC	No method established	No
VERMONT PSB		
VIRGINIA SCC	3	Yes, applies to all, not just QFs
WASHINGTON UTC	5, proxy resource method (energy mostly given to PN Hydro to break up peaking	No
WEST VIRGINIA PSC	2	Yes
WISCONSIN PSC		
WYOMING PSC	2, purchase surrogate "Actual cost"	Yes
NOVA SCOTIA URB	2, 3	No

1=Peaking Plant as a Proxy
2=Next Proposed Generating Plant as a Proxy
3=Estimate Costs with a Generating Expansion Model
4=Estimate Costs with a Production Costing Model
5=Prices Established Through Competitive Bidding
6=Other - Specify

DPU EXHIBIT #RLW-2

PacifiCorp
Qualifying Facilities 1 MW and Less in Size

	Total	Hydro	Wind	Other
California				
No. of Projects	5	4	1	0
Capacity (MW)	0.504	0.490	0.014	0.000
Idaho				
No. of Projects	11	11	0	0
Capacity (MW)	4.815	4.815	0.000	0.000
Montana				
No. of Projects	1	1	0	0
Capacity (MW)	0.225	0.225	0.000	0.000
Oregon				
No. of Projects	15	12	3	0
Capacity (MW)	2.696	2.688	0.008	0.000
Utah				
No. of Projects	4	2	1	1
Capacity (MW)	1.626	1.041	0.018	0.567
Washington				
No. of Projects	1	0	1	0
Capacity (MW)	0.002	0.000	0.002	0.000
Total Company				
No. of Projects	37	30	6	1
Capacity (MW)	9.867	9.259	0.041	0.567