IDAHO
PUBLIC UTILITIES
COMMISSION

Dirk Kempthorne, Governor

P.O. Box 83720, Boise, Idaho 83720-0074

Paul Kjellander, President
Marsha H. Smith, Commissioner
Dennis S. Hansen, Commissioner

April 7, 2004

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IDAHO PUBLIC
UTILITIES COMMISSION

TO: Commission Secretary
Parties of Record

FROM: Scott Woodbury

DATE: April 7, 2004

RE: Case No. IPC-E-04-5

On April 6, 2004, Staff submitted Comments in the above case. The Comments reference an attached Order No. 26576 and Settlement Stipulation (and Exhibit) in Case No. IPC-E-95-9, which was not filed with the Comments. Please add the attachment to your Staff Comments dated April 6, 2004.

Scott Woodbury
Deputy Attorney General

Located at 472 West Washington Street, Boise, Idaho 83702
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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AN ORDER APPROVING THE METHODOLOGY FOR AVOIDED COST RATE NEGOTIATIONS WITH QUALIFYING FACILITIES LARGER THAN 1 MEGAWATT.

CASE NO. IPC-E-95-9

ORDER NO. 26576

BACKGROUND

On July 17, 1995, the Idaho Power Company (Idaho Power; Company) filed an Application for an Order approving a methodology for conducting avoided cost rate negotiations with qualifying facilities (QFs) 1 megawatt (MW) or larger.

Idaho Power's Application was anticipated by the Commission in Order No. 25884 (issued in Case No. IPC-E-93-28) in which the Commission stated:

> We expect the Company to include with its 1995 IRP filing, a more detailed proposal of how the least cost planning based avoided cost methodology will operate. We will treat that filing as a generic discussion of the issue and expect all interested parties, including the other utilities, to intervene and participate so that all issues may be resolved and the methodology can be refined.

Order No. 25884 at p. 7

Pursuant to the Commission's directive, The Washington Water Power Company (Water Power) and PacifiCorp were designated as parties to this proceeding. In addition, a number of independent power developers intervened as parties.

Subsequent to the filing of Idaho Power's Application, a number of interested parties conducted a series of settlement negotiations in an attempt to craft an avoided cost methodology for larger projects that was acceptable to all concerned. With the exception of several issues, the parties were ultimately able to agree upon a methodology which was formulated primarily by the Commission Staff but with the assistance of all those who participated in the settlement negotiations. The proposed methodology, which is based essentially on each utility's integrated resource plan, was included as Exhibit No. 101 to the testimony of Commission Staff witness Rick Sterling presented at the technical hearing conducted by the Commission in this case on July 2, 1996.

Under the proposed methodology, the avoided cost of a QF project is determined as the cost which the utility would avoid if it purchased power from the QF, rather than acquiring the same power from the resources selected in its base case resource plan. The value of power from the QF is dictated by the type, amount, timing and cost of the resources in the IRP which would be displaced or deferred.

With the exception of three issues discussed below, none of the parties who participated in this case objected to Staff's proposed methodology. In fact, Idaho Power, Water Power, PacifiCorp and Rosebud Enterprises, Inc. executed the Settlement Stipulation agreeing to Staff's proposed methodology with the three exceptions. The other parties to the case chose not to sign the Stipulation but did not oppose the methodology.

The three unresolved issues relate to the standard contract term over which QFs are entitled to receive the avoided cost rate, whether levelized rates should be offered to QFs and whether PacifiCorp should be allowed to adjust the input data used in the Company's IRP model to reduce PacifiCorp's reserve margin from 12% to 10%.

DISCUSSION AND FINDINGS

We commend the parties for the considerable time and energy expended in addressing what has long been one of the most contentious matters to come before this Commission; the setting of avoided cost rates. When we issued Order No. 25884, we recognized that the use of a surrogate avoided resource (SAR) for setting avoided cost rates for larger QF projects was no longer adequate given the rapidly changing nature of the industry and the manner in which utilities actually acquire resources. The Commission Staff and the other parties to this case have answered the call in devising a methodology that more closely reflects the manner in which utilities acquire and price generation resources than did the use of a single, hypothetical power plant. As we discuss below, the industry is changing with such speed that the use of any particular formula for setting avoided cost rates will have inherent shortcomings. Nonetheless, we find that the methodology proposed by the parties in this case is the most reasonable means of establishing avoided cost rates for larger QFs at this time. We now turn to the issues left unresolved by the Settlement Stipulation.

Contract Length

The Commission's current policy, as established in Order No. 21630, Case No. U-1500-170, is that QFs are entitled to contracts up to 20 years. Although the actual useful life of the project may exceed that time period, the QFs are free to renegotiate a contract with the utility or with any other buyer at the expiration of the 20-year term. In this proceeding, the Commission Staff advocates maintaining the standard 20-year contract term. Staff contends that it is reasonable to require 20-year contracts for QFs since utilities' long-term acquisition planning is still primarily based on the acquisition of long-lived resources under long-term commitments including the relicensing of hydro projects and DSM programs. Staff reasons that as long as the rates that utilities pay for QF power are based on the utility's avoidance of planned resources, the utilities should be required to offer 20-year contracts if the planned resources have lives of 20 years or more. Staff believes that although utilities are currently relying on short-term market purchases to satisfy their short-term needs, the fact that their respective IRPs call for the acquisition of long-term resources cannot be overlooked and justifies requiring 20-year contract terms for QF projects. Staff argues that short-term market purchases can be used in the proposed methodology, but only to the extent those market purchases have been included in the utility's IRP.

Idaho Power proposes that the standard contract terms for QF projects larger than 1 megawatt should no longer be a fixed contract length. Rather, the expectation should be that QFs will be offered contracts with terms "similar in length to those offered by the utility for other resources being acquired contemporaneously." Idaho Power's witness John Willmorth argues that, due to the current surplus of resources in the region and the uncertainty about future resource needs, resources are being acquired by utilities for periods generally no longer than five years. Consequently, the maximum contract length which should be offered to large QFs at this time should not exceed five years, he argues. Idaho Power contends that it has no plans to build, own or operate new generating facilities to meet load growth. Instead, as the competitive wholesale power markets expand, Idaho Power plans to supplement its existing resources as necessary with market purchases of capacity and energy. These will be short-term purchases, the Company argues, and consequently, Idaho Power should not be required to offer QF contracts greater than five years during this period of transition.

Willmorth argues that although Idaho Power had originally proposed the IRP methodology, it will not remain a viable basis for calculating utility avoided costs given the dynamic nature of the industry. He suggests that competition is likely to radically change or eliminate the need for the IRP and to erode the relationship between the determination of avoided cost and the resource plans of individual utilities. Consequently, avoided costs will need to be calculated using a more direct market price methodology. He urges the Commission to convene a proceeding shortly after concluding this case to investigate the future role of the IRP and the feasibility of eliminating administratively determined avoided costs in favor of a direct determination of the QF rate from the published price of an equivalent market purchase.

PacifiCorp also believes that avoided cost rates must soon be established by a more market-based methodology but agrees that Staff's proposed methodology is appropriate for the interim. Like Idaho Power, PacifiCorp opposes the standard 20-year contract term for QFs arguing that it unduly protects them from the competitive market forces with which all other wholesale market participants have to contend and leads to overstated avoided cost prices. PacifiCorp proposes that any QF contracts offered in excess of five years should include a market adjustment clause to avoid the risk that utilities' customers will pay prices for QF power that is in excess of current market prices.

PacifiCorp proposes that the contract structure and pricing terms offered to QF developers should reflect those in the market, i.e., what is avoided by a QF contract. The Company argues that the optimal contract structure the Commission should adopt includes a five-year term with a developer option for full levelization during that term. If the terms are kept to five years or less, the Company does not believe that market adjustments would be necessary or appropriate. Pricing in the subsequent periods would be based on subsequent market conditions. If the Commission decides to continue with contract terms in excess of five years, PacifiCorp proposes that it be allowed to include provisions in its contracts which would allow the risk of longer term contracts to be shared. For instance, the Commission could adopt contracts which have five years of initial pricing followed by market adjustments at the beginning of the sixth, eleventh and sixteenth years. The market adjustment would true-up prices to a published market index such as the California-Oregon Border or Palo Verde electricity indexes or other indices which are a good measure of current electricity prices. Prices between adjustment years could be based on the prior year's price adjusted by an inflation index.

The second option could involve a plus or minus 10% deadband being placed around a predetermined price. If the actual price of electricity in the market were outside the deadband, prices would automatically be reset to the published market price with a new deadband established.

Water Power also opposes maintaining the 20-year contract term. As an alternative to Staff's proposal, Water Power recommends that utilities be required to offer fixed prices for terms no longer than five years. Water Power witness Douglas Young suggests that QF developers should be able to request long-term contracts up to ten years, but after five years the price provisions of the contracts should be renegotiated or revised to reflect then current market conditions. Young asserts that the electric industry is in such a state of flux that 20-year price forecasts are not possible. Furthermore, he argues that five years is closer to the average length of electric purchase and sales transactions which Water Power has recently experienced in the power market.

Rosebud's witness Richard Slaughter advocates maintaining the standard 20-year contract term. He notes that short-term market prices could just as easily rise as fall and that this has always been the case in the industry. He suggests, in fact, that there are reasons to believe that the low gas prices experienced in recent years may soon start to rise as utilities become increasingly reliant upon this resource and supply becomes increasingly scarce. In any event, he contends, it is unlikely that gas prices will fall much lower. Slaughter notes that under the various utilities' proposals, utility shareholders and ratepayers would both benefit in the event that market prices decline. If they were to increase, however, ratepayers would bear the entire burden because contracts with QFs would be renegotiated at higher prices. Finally, Slaughter notes that no developer can obtain financing for a project with a guaranteed price of only five years. Consequently, he asserts, that without contracts of at least 20 years, there will be no competition in the energy market from qualified developers. Slaughter also questions the credibility of utilities who, on the one hand contend that they wish to treat QF resources the same as their own, yet are not proposing to forego rate base treatment of long-lived, Company-owned assets, e.g., hydro relicensing, DSM, etc.

We find:

PURPA was enacted to encourage the promotion and development of renewable energy technologies as alternatives to fossil fuels and the construction of new generating facilities by electric utilities. *American Paper Institute, Inc. v. American Electric Power Service Corp.*, 461 U.S. 402, 103 S.Ct. 1921, 76 L.Ed.2d 22 (1983). Pursuant to congressional directive, FERC promulgated rules implementing sections 201 and 210 of PURPA. Section 210 requires electric utilities to purchase electricity produced by QFs. 16 U.S.C. § 824a-3(b), (d).

Under FERC rules, utilities are required to purchase QF power at a rate of payment equal to the utility's full avoided cost. 18 C.F.R. § 292.304(b)(2). "Avoided costs" are the incremental costs to the electric utility of power which, but for the purchase from the QF, such utility would generate itself or purchase from another source. 18 C.F.R. § 292.101(b)(6).

FERC promulgated the general scheme and rules but left the actual implementation of establishing avoided costs to the regulatory authorities of the individual states. The grant of authority to the states in implementing the regulation of sales and purchases between QFs and electric utilities, both substantively and procedurally, is broad. *See*, *Federal Energy Regulatory Commission v. Mississippi*, 456 U.S. 472, 102 S.Ct. 2126, 72 L.Ed.2d 532 (1982).

PURPA, and the implementing regulations, require only that avoided costs be established and made available to QFs with a capacity of 100 kilowatts or less. 18 C.F.R. § 292.304(c). The Act and regulations are silent as to the length of the contract over which the QF is entitled to receive the avoided cost rate. Consequently, this is a matter that lies within this Commission's discretion. The Commission's policy with respect to the standard contract length has evolved over the years. Prior to 1987, utilities were obligated to provide QFs with 35-year contracts. In Order No. 21630, issued in Case No. U-1500-170, the Commission shortened the standard contract length to 20 years reasoning that risk and uncertainty inherent in long-range forecasting increases dramatically with time and that a shorter contract term would reduce that risk. The Commission ruled that contracts longer than 20 years would be available to QFs only upon a persuasive showing of need.

Significant changes have swept through the electric industry since we last examined the issue of contract length. The FERC has mandated open access to the transmission system, thermal technologies have improved, gas prices are low, there is a considerable surplus of energy available in this region resulting in very low spot market prices for electricity and, finally, even the continued existence of PURPA is being called into question. We find that as the industry as a whole continues to transform to a more free market model, we cannot justify obligating utilities to 20-year contracts for PURPA power. As the utilities in this case note, such an obligation does not reflect the manner in which they are currently acquiring power to meet new load; through short-term (five years or less) purchases. Consequently, it would be nothing more than an artificial shelter to the QF industry to provide those projects with contract terms not otherwise available in the free market. We can find no justification for insisting that Idaho's investor-owned utilities and their ratepayers assume such an obligation simply to foster one particular segment of an increasingly competitive industry. We find, therefore, that Idaho's investor-owned utilities shall not be required to offer contracts to QFs in excess of five years until further action is taken by this Commission. This ruling, however, does not prevent utilities from offering for approval QF contracts with terms that exceed five years should the utilities believe that such contracts are in the best interests of their ratepayers.

Levelized Rates

Under the Commission's current policy, levelized rates are available to any QF developer who desires them. Nonlevelized rates are high in later years of the contract while levelized rates are equal throughout the contract term. Levelized rates are often considered essential by developers of projects with high, up-front capital costs.

The arguments for and against offering levelized rates for QF projects are essentially the same as with respect to contract length. Staff simply argues that the levelization of rates is not an issue in this case. In the combined avoided cost cases, WWP-E-93-10, IPC-E-93-28, PPL-E-93-5/UPL-E-9-37 and UPL-E-93-3/PPL-E-93-3, which initiated the present proceeding, the Commission stated in Order Nos. 25882, 25883 and 25884:

> The levelization of avoided cost payments is another tool that this Commission has historically relied upon in encouraging and assisting smaller QFs by providing a cash stream that better enables them to satisfy their debt service in the early years of their contracts. Although, we have taken considerable strides toward market-based pricing, we find that levelization for projects above 1 MW should be continued. We believe that levelization more accurately reflects the way in which costs are recovered for utility-owned projects. The utilities are directed to provide levelized rates, for all QF projects who desire it, utilizing the same procedure incorporated in the SAR methodology.

Idaho Power does not support mandatory rate levelization but agrees that it is a legitimate item for contract negotiations on a case-by-case basis. Willmorth suggests that an appropriate standard is that QFs should be offered the same opportunity for rate levelization as is contemporaneously being offered by the utility for similar alternative purchases. He argues that the issues of contract length and rate levelization are related. When actual avoided costs tend to increase year after year, rate levelization results in shifting avoided costs from the later years of the QF contract into the earlier years of the contract thereby producing QF rates which systematically exceed avoided costs through a portion of the contract life. The shorter the contract length, the less the cost shifting and early overpayment in rates due to rate levelization.

PacifiCorp argues that rate levelization should be offered but under the condition that contract length not exceed five years.

Water Power disagrees with Staff's contention that rate levelization is not an issue in this case. According to witness Douglas Young, levelization is incident to the pricing provisions of purchase contracts. Water Power simply argues that so long as contract length does not exceed five years, the risks attendant to rate levelization are acceptable to the Company.

Finally, Rosebud witness Slaughter argues that levelization is as important as a 20-year contract term for facilities with high capital cost and low fuel expense. He argues that levelization also presents the ratepayer with a rate risk most similar to that experienced with utility-owned plants. He suggests that a levelized long-term contract is the resource whose attributes are most like utility-owned plant. He concedes that there are risks in such arrangements but argues that there are also potential rewards especially as the energy market approaches the lower bound of its long-term cost history.

We find:

The three utilities in this proceeding agreed that if the standard contract length were reduced to five years, that levelized rate should be offered to any QF desiring them. We find, therefore, that all QFs larger than 1 MW shall be entitled to levelized rates should they so desire them.

Reserve Margin

PacifiCorp, through the prefiled testimony of witness Laren Hale, proposed a number of changes to the input data used in the Company's IRP model to calculate avoided cost rates that are different than data contained in RAMPP-4; the most recent IRP.

Staff believes that all of the changes should be allowed with one exception; reducing the reserve margin from 12% to 10%. According to Staff witness Sterling, all of the other changes are either identified in the section of the Company's IRP titled "Revisions to Inputs," are necessary in order to use the model for avoided cost calculations or allowed by the Settlement Stipulation to be updated on a semi-annual basis. Sterling argues, however, that a reduction in PacifiCorp's reserve margin was not identified in the IRP or its revisions and is not specifically permitted by the Stipulation.

In rebuttal, PacifiCorp witness Weaver concedes that the Settlement Stipulation does not allow for a revision to the Company's reserve margin which is why the Company is now seeking Commission approval. Weaver notes that the issue of reserve margin is currently under discussion in the Company's RAMPP-5 IRP. Because of the regional surplus of capacity, PacifiCorp believes that a reduction in reserve margin is warranted.

We find:

Pursuant to the settlement discussions, the three investor-owned utilities that are party to this proceeding were allowed 45 days in which to make amended IRP filings for the purpose of making avoided cost calculations. This invitation to make amended filings was set forth in the Notice of Scheduling in the three utilities' pending IRP cases. PacifiCorp never made an amended filing in response to this invitation. Instead, it included proposed changes to its reserve margin for the first time in the prefiled testimony of one of its witnesses.

We find that it would be inappropriate to allow PacifiCorp a last minute amendment to its IRP in a case not initiated for that purpose, and in which no notice was given that such an amendment may occur. This Commission has previously established a methodology for the filing and review of utilities' IRPs and we are not compelled to bypass that methodology by allowing a last minute change in an unrelated case. We further note that PacifiCorp will file its next IRP (RAMPP-5) in early 1997. That is the proper proceeding in which to review the adequacy of the Company's reserve margin.

ORDER

IT IS HEREBY ORDERED that the Settlement Stipulation set forth in Staff Exhibit No. 101 establishing a methodology for setting avoided cost rates for QFs 1 MW and larger is hereby approved subject to the terms and conditions set forth herein.

THIS IS A FINAL ORDER. Any person interested in this Order (or in issues finally decided by this Order) or in interlocutory Orders previously issued in this Case No. IPC-E-95-9 may petition for reconsideration within twenty-one (21) days of the service date of this Order with regard to any matter decided in this Order or in interlocutory Orders previously issued in this Case No. IPC-E-95-9 . Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. See *Idaho Code* § 61-626.

DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 4th day of ~~August~~ September 1996.

Ralph Nelson
RALPH NELSON, PRESIDENT

Marsha H. Smith
MARSHA H. SMITH, COMMISSIONER

Dennis S. Hansen
DENNIS S. HANSEN, COMMISSIONER

ATTEST:

Myrna J. Walters
Myrna J. Walters
Commission Secretary

vld/O:IPC-E-95-9.bp2

Attachment 1
Case No. IPC-E-04-5
Staff Comments
04/06/04 Page 10 of 34

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR AN ORDER APPROVING THE METHODOLOGY FOR AVOIDED COST RATE NEGOTIATIONS WITH QUALIFYING FACILITIES LARGER THAN 1 MEGAWATT	)	CASE NO. IPC-E-95-9 SETTLEMENT STIPULATION

Pursuant to Rules 271-277 of the Commission's Rules of Procedure (IDAPA 31.01.01), the undersigned, including but not limited to the Staff of the Idaho Public Utilities Commission ("Staff"), Idaho Power Company, ("Idaho Power"), the Washington Water Power Company ("WWP"), PacifiCorp ("PacifiCorp"), and Rosebud Enterprises, Inc. ("Rosebud"), herein collectively referred to as the "Parties", by and through their respective counsel of records, hereby stipulate as follows:

I. BACKGROUND

On July 17, 1995, Idaho Power filed an application for an order approving a methodology for conducting avoided cost rate negotiations with qualifying facilities (QF's) 1 MW or larger. Idaho Power's application was docketed as Case No. IPC-E-95-9.

Idaho Power's application was anticipated by the Commission in Order No. 25884 (issued in Idaho Power's most recent avoided cost proceeding, Case No. IPC-E-93-28) in which the Commission stated:

> "We expect the Company to include with its 1995 IRP filing, a more detailed proposal of how the least cost planning based avoided cost methodology will operate. We will treat that filing as a generic discussion of the issue and expect all interested parties, including the other utilities, to intervene and participate so that all issues may be resolved and the methodology can be refined." *id at P. 7.*

On August 14, 1995 in Order No. 26115, the Commission provided public notice of Idaho Power's application and made WWP and PacifiCorp parties to Case No. IPC-E-95-9.

On August 16, 1995, the Commission staff issued a Notice of settlement negotiations to be undertaken pursuant to Rule 272 of the Commission's Rules of Procedure, IDAPA 31.01.01. Subsequently, the following parties intervened in Case No. IPC-E-95-9, and to varying degrees participated in the settlement negotiations that were undertaken pursuant to the August 16, 1995 notice of settlement negotiations: Idaho Power Company, Commission Staff, Washington Water Power Company, PacifiCorp, the Independent Energy Producers of Idaho, Myers Engineering Company, Earth Power Resources, Inc., Irrigation Districts and Rosebud Enterprises, Inc.

Following the August 16, 1995 Notice, settlement negotiations were undertaken at the Commission's offices on August 29, 1995, January 3, 1996, and March 20, 1996. As a result of the settlement negotiations, the Parties developed a methodology for conducting avoided cost rate negotiations which is entitled "Staff's Proposed Avoided Cost Methodology for Projects Larger than 1 MW, Case No. IPC-E-95-9" ("Staff Proposal"). The Staff Proposal methodology was the subject of both written comments and substantial discussions at the settlement conferences. The most recent version of Staff's Proposal is attached hereto as Exhibit 1. In conformance with the Parties' settlement discussions, the Parties hereby submit this Settlement Stipulation to the Commission and request that the Commission accept and approve the attached Exhibit 1 Staff Proposal as the methodology for computing avoided costs and for conducting avoided cost rate negotiations for QF projects 1 MW and larger.

II. AGREEMENTS

(1) The Parties have negotiated this Settlement Stipulation and Exhibit 1 as a part of a settlement proceeding. Each of the Parties may not agree with all of the provisions of Exhibit 1 but they are each willing to accept Exhibit 1 as a reasonable compromise of contested positions. If the Commission does not accept this Stipulation and Exhibit 1 in their entirety, without modification, it will be withdrawn and shall be without any force or effect.

(2) By executing this Stipulation, the Parties agree to recommend that the Commission issue an order adopting Exhibit 1 as the methodology for computing avoided costs and

for conducting avoided cost rate negotiations for QF projects 1 MW and larger and agree to file testimony in support of the Stipulation.

(3) This Settlement Stipulation may be signed in counterparts.

III. ADDITIONAL ISSUES

As Exhibit 1 evidences, the Parties were able to resolve the vast majority of the issues that are associated with establishing the IRP methodology. Nevertheless, there were several issues raised during the negotiations upon which the Parties were unable to achieve consensus. The unresolved issues generally relate to rate levelization and length of contract. On those issues, the positions of the Parties fell into two general categories. One group, primarily the utilities, maintained that contract length and rate levelization should be individually negotiated based on the utilities' specific IRPs and the individual characteristics of the project. In addition, the utilities argued that long term contracts must include a mechanism to allow periodic rate adjustments to track changes in market prices for electric capacity and energy. The other position, as expressed primarily by QF developers, was that the Commission should require that QF developers have the option of obtaining long term contracts containing levelized or non-levelized avoided cost payments. In addition, the parties were unable to agree on the treatment of non-deferrable resources within the methodology. The consensus of the Parties was that the Commission could address all unresolved issues at the hearing scheduled for consideration of the Settlement Stipulation.

DATED This 6th day of June, 1996.

IDAHO PUBLIC UTILITIES COMMISSION

By: ______________________________
Brad Purdy
Deputy Attorney General

IDAHO POWER COMPANY

By: ______________________________
Barton L. Kline

WASHINGTON WATER POWER CO.

By: ______________________________
R. Blair Strong

PACIFICORP

By: ______________________________
John M. Eriksson

DATED This 3rd day of June, 1996.

IDAHO PUBLIC UTILITIES COMMISSION

By:______________________________
Brad Purdy
Deputy Attorney General

IDAHO POWER COMPANY

By:______________________________
Barton L. Kline

WASHINGTON WATER POWER CO.

By:______________________________
R. Blair Strong

PACIFICORP

By:______________________________
John M. Eriksson

DATED This 7th day of ~~May~~ June, 1996.

IDAHO PUBLIC UTILITIES COMMISSION

By:____________________
Brad Purdy
Deputy Attorney General

IDAHO POWER COMPANY

By:____________________
Barton L. Kline

WASHINGTON WATER POWER CO.

By: R. Blair Strong
R. Blair Strong

PACIFICORP

By:____________________
John M. Eriksson

DATED This 5th day of June, 1996.

IDAHO PUBLIC UTILITIES COMMISSION

By:____________________________
Brad Purdy
Deputy Attorney General

IDAHO POWER COMPANY

By:____________________________
Barton L. Kline

WASHINGTON WATER POWER CO.

By:____________________________
R. Blair Strong

PACIFICORP

By: [signature]
John M. Eriksson

DATED This _____ day of _____________, 1996.

INDEPENDENT ENERGY PRODUCERS OF IDAHO

By:______________________________
Peter J. Richardson

MYERS ENGINEERING COMPANY

By:______________________________
John Runft

EARTH POWER RESOURCES, INC.

By:______________________________
Peter J. Richardson

IRRIGATION DISTRICTS

By:______________________________
Don A. Olowinski

ROSEBUD ENTERPRISES, INC.

By:______________________________
Owen H. Orndorff

DATED This _____ day of _____________, 1996.

INDEPENDENT ENERGY PRODUCERS OF IDAHO

By:______________________________
Peter J. Richardson

MYERS ENGINEERING COMPANY

By:______________________________
John Runft

EARTH POWER RESOURCES, INC.

By:______________________________
Peter J. Richardson

IRRIGATION DISTRICTS

By:______________________________
Don A. Olowinski

ROSEBUD ENTERPRISES, INC.

By:______________________________
Owen H. Orndorff

STAFF'S PROPOSED AVOIDED COST METHODOLOGY FOR PROJECTS LARGER THAN ONE MEGAWATT CASE NO. IPC-E-95-9

Introduction

On January 31, 1995, the Idaho Public Utilities Commission issued Order Nos. 25882, 25883, and 25884 which required that utilities utilize their Integrated Resource Plans (IRPs) to establish avoided cost rates for projects larger than one megawatt. The Commission stated the following in its orders:

> We believe that the adoption of the least cost planning methodology is consistent with our goal of maintaining a regulatory climate that allows our electric utilities to retain their advantageous posture in a marketplace that is likely to become increasingly competitive. This will ultimately work to the advantage of ratepayers in the form of rates lower than would otherwise be in effect. By treating QFs [Qualifying Facilities] in the same manner as utility acquired resources, we are further removing the shelter that has been constructed around the QF industry. Requiring those projects to prove their viability by market standards insures that utilities will not be required to acquire resources priced higher than would result from a least cost planning process. Ratepayers will not be disadvantaged and QFs will be treated fairly and consistently with the requirements and goals of PURPA.

See, e.g. Order No. 25884 at page 6.

In accordance with Order No. 22299, all utilities are required to prepare IRPs biennially. The following elements are included in the development of the IRP:

1. Integrated evaluation of all resource options;
2. Least cost selection criterion for the resource plan;
3. Inclusion of environmental impacts and external costs of resources;
4. Analysis of planning uncertainties and risks; and
5. Public involvement in the planning process.

An IRP forms the basis for utility decisions regarding the timing, quantity, and type of future resource acquisitions. The end result of integrated resource planning is a set of resource options which represent the least cost means of meeting expected future loads considering a reasonable range of planning uncertainties and risks. The set of options with the highest probability of having the least cost, and which has an acceptable level of risk, is usually referred to as the "base case" plan. The base case plan is the starting point of the analytical process described in this document for determining project-specific avoided cost rates for QF projects larger than 1 MW.

In the past, utilities have submitted IRPs to the Commission for filing, but no formal process has been in place for detailed review or approval of the IRPs. However, as a result of their increased utilization and importance as something other than a planning document, utilities should expect their plans to be scrutinized more carefully in the future. The Commission Staff intends to conduct thorough reviews of the plans, and anticipates that hearings may be held to provide an opportunity to seek comment. As in the past, utilities should not be bound to follow their IRP without exception. In fact, when good cause is shown, they should be expected to deviate from it. But absent good cause, they should now expect to be held to it more closely. More importantly, the IRP will establish the standard against which all resource acquisitions will be judged, both utility and non-utility owned alike.

Public participation is required in the preparation of utility IRPs. Developers and their representatives shall be welcome to participate in any public meeting related to the development of a utility IRP. It is the utility's responsibility to offer invitations to participate to a broad cross section of interested parties. The responsibility to actually participate lies with the interested parties.

The opportunity for developers or other interested parties to ultimately influence the calculation of avoided cost and the rates for QF projects that are derived from that calculation, is in the development of a utility's IRP, not in the application of the avoided cost methodology. The IRP is the source of all inputs used in the calculation of avoided costs. It is the real basis for calculating avoided cost rates. Once the avoided cost methodology is established, Staff does not expect a hearing or other formal Commission proceeding to be initiated each time a utility's avoided costs are calculated.

General Methodology

PURPA defines avoided cost as "the cost to an electric utility of electrical energy or capacity or both which, but for the purchase from such cogenerator or small power producer, such utility would generate itself or purchase from another source" *18 CFR, § 292.101*.

As explained by FERC:

> This definition is derived from the concept of "the incremental cost of alternative electric energy" set forth in section 210(d) of PURPA. It includes both the fixed and the running costs on an electric utility system which can be avoided by obtaining energy or capacity from qualifying facilities. One way of determining avoided cost is to calculate the total (capacity and energy) costs that would be incurred by a utility to meet a specified demand in comparison to the cost that the utility would incur if it purchased energy or capacity or both from a qualifying facility to meet part of its demand and supplied its remaining needs from its own facilities. The difference between these two figures would represent the utility's net avoided cost. In this case, the avoided costs are the excess of the total capacity and energy costs of the system developed in accordance with the utility's optimal capacity expansion plan, excluding the qualifying facility, over the total capacity and energy costs of the system (before payment to the qualifying facility) developed in accordance with the utility's optimal capacity expansion plan including the qualifying facility. (Order No. 69 [45 Fed. Reg. 12,216, 1980]).

In the proposed methodology, the avoided cost of a QF project is determined as the cost which the utility would avoid if it purchased power from the QF, rather than acquiring the same power from the resources selected in its base case resource plan. Put another way, the avoided cost of the QF project is the difference in the present value of revenue requirements (PVRR) between the base case resource plan and a modified resource plan that includes the QF resource. The avoided cost determination involves the following steps:

1. An IRP is prepared for the utility. The IRP should consider a range of load forecasts for various sets of possible economic conditions. The IRP should also consider all possible resources for meeting load, both supply side and demand side. In addition, consideration should be given to the risks and uncertainties associated with each scenario examined. The least cost combination of resources is selected to meet each scenario. The most likely scenario is identified as the base case plan.

2. An initial simulation analysis using a power supply and/or capacity expansion model chosen by the utility is used to calculate the PVRR of the base case resource plan over the lifetime of the proposed QF contract.

3. The proposed QF resource is added to the base case resource plan during all years of the proposed contract. The required description of the QF project includes all data and information needed to model the intended dispatchable or non-dispatchable operation of the project on the power supply system (see pps. 9-10 for a list of data and information needed from QFs).

4. A second simulation analysis, including the QF resource, is performed which results in an adjustment of the amount and/or timing of the new resources in the base case plan. The modified plan including the QF purchase is constructed to maintain resource adequacy and system reliability equivalent to that of the base case plan.

5. The PVRR of the modified resource plan including the QF is calculated over the full term of the QF contract, excluding the total purchase costs of the QF resource itself.

6. Finally, the present value of the QF project avoided cost is calculated by subtracting the PVRR of the modified plan, with costs of the QF set to zero, from the PVRR of the base case resource plan.

7. Rates for capacity and energy from the QF project can now be developed for which, on a present value basis, the expected payments to the QF are equal to the project's avoided cost over the life of the contract.

IRP Data for Avoided Cost Calculations

Many of the same variables must be chosen and many of the same assumptions must be made by each utility in the development of their IRP. For example, each utility must make assumptions about inflation, the price of natural gas, or the cost of building a coal plant. Some planning variables will probably be the same for all utilities, but many will be different. In the past, the Commission has specifically determined both generic and company-specific variables used to calculate avoided cost for large projects. With implementation of the IRP methodology, the Companies will be responsible for determining these variables. As long as the values and assumptions fall within a reasonable range, utilities are free to choose values most appropriate for their own situation. It follows then, that different utilities will likely assume different values for the same variables. No variables will be considered generic; all variables will be utility specific, as are the utilities' IRPs. In granting utilities the freedom to select their own variables, utilities should be aware that they will be required to analyze their own resources on an equal footing with QF resources.

Portfolio Resources

The resource portfolio of each utility should include a variety of both supply and demand side resources. Market purchases also represent a future supply option, and will likely comprise an increasingly larger portion of utilities' resources in the future. In fact, for some utilities, market purchases may constitute the primary source of new resources. The cost of market resources, to the extent a utility relies on them, should be one component in determining utilities' avoided costs. However, in order for market resources to be considered in the determination of avoided costs in an IRP-based methodology, those market resources must be included in the IRP. Any market purchases made that are not anticipated in the IRP cannot be used in the calculation of avoided costs. However, due to the fact that Pacificorp's RAMPP-4 calibration of its IPM model does not provide for the IPM's calculation of avoided costs, Pacificorp will be allowed to propose modifications to the IPM calibrations for the purpose of determining avoided costs, subject to Commission approval in Case No. IPC-E-95-9.

Predicting the price and availability of market resources, particularly in the long term, is difficult and uncertain. Consequently, forecasts made in the IRP should be firmly based on sound reasoning and analysis. The degree of planned reliance on market resources should be a matter of interest to ratepayers, shareholders, the Commission and the public. Review of the utilities' planned reliance on the market however should occur in the context of an IRP filing, not in an avoided cost proceeding.

Demand side resources to which the utility has made a firm commitment should be considered as reductions in the load forecast rather than as supply side resources, in part, to discourage double counting.

Load and Resource Forecasts

Forecasts of electricity load growth are made by each utility at two-year intervals as a part of IRP filings. These forecasts serve as the basis for avoided cost calculations. Staff contends that only known, measurable, and easily documented changes should be made to the forecasts during the interim periods between required filings. For example, discrete changes in load that could be traced to the addition or loss of a single major customer would be a known, measurable, and easily documented change. The signing or expiration of a power sales or exchange agreement would also be a known, measurable, and easily documented change, as would the signing of a new QF contract.

On the other hand, a load change due to population growth may be known, but would not be easily measured or documented.

Updating IRP Data

For the most part, utilities' resource plans as set forth in their IRPs should guide resource acquisition activities, including the resource cost effectiveness and avoided cost determinations, until replaced by subsequent IRPs. One of the goals of this avoided cost methodology is to achieve a dynamic resource evaluation process that recognizes changes in loads, technologies, costs, availabilities, and economic conditions so that utilities' avoided costs are accurately determined. However, QF developers seek to maintain some stability of avoided cost rates so that they are able to plan projects with some degree of certainty. In addition, the public must have the opportunity to participate in the planning process to provide input regarding variables that are ultimately used in each utility's IRP.

To achieve some balance between these competing objectives, this methodology allows periodically scheduled changes to some variables, while keeping other variables fixed between IRP filings. In essence, there will be a core set of variables that are used in the IRP and in the determination of avoided cost rates, but a subset of those variables will be changed periodically for the purpose of accurately calculating avoided costs. Every two years, a new IRP will be filed with new core variables and variables that will be adjusted periodically.

Generally, variables which are acquired from independent third party sources and which are updated at regular intervals can be adopted by utilities for use in avoided cost calculations. However, the same source must be consistently used. Any change in the source of the data must also be agreed to by the Commission. Semi-annual updates will be allowed for the following based on verifiable forecasts:

- Escalation rates for capital costs;
- Escalation rates for O&M expenses;
- Escalation rate for fuel prices;
- Fuel prices.

If multiple sources are used to establish values for these variables, such as for gas prices, or if a utility wishes to make adjustments to values in consideration of regional circumstances, the utility should propose the sources and adjustment mechanisms at the time of their next IRP filing for consideration by the Commission. The utility should consistently use the same sources and adjustment mechanisms in the future for determining avoided cost rates unless changes are authorized by the Commission.

At such time as easily verifiable information is readily available from independent third party sources, the following variables may also be updated semiannually:

- Wholesale power price;
- Wholesale power price escalation rates;
- Wholesale power available for purchase.

The variables must be reflective of the same wholesale power products used for analysis in the IRP, so that no adjustment of the variables is needed before they can be used in the IRP or in calculating avoided cost rates. Permission must be obtained from the Commission before these variables may be updated on a semi-annual basis for avoided cost purposes.

Staff recommends that updates to resource portfolio data, such as plant capital costs, operation and maintenance costs, heat rates, generation capacities, plant factors, economic life, etc. not be allowed except during biennial IRP submissions. Updates to load forecasts, except for known and measurable changes as discussed previously, should also not be allowed except during IRP submissions.

Variables that go into calculating utilities' before and after tax cost of capital should be updated on a regular basis also. Staff proposes that these variables be updated biennially upon submission of new IRPs. Utilities may use estimated values for weighted cost of capital, and should assume a hypothetical capital structure reflecting the typical degree of leveraging for electric utilities with "A" grade bond ratings. Alternatively, utilities may use the weighted cost of capital as established in the utility's most recent general rate case.

To the extent they affect resource costs, the passage of new laws and the imposition of new regulations may trigger changes in variables. Staff recommends Commission approval be required however, before variables can be changed for the purpose of determining avoided costs as a result of these types of factors.

Publication of Rates

In order to provide benchmark avoided cost rates which potential QF developers can use for planning purposes, Staff recommends utilities be allowed to publish avoided cost rates for hypothetical projects. The rates should be published semiannually at the time changes in variables are submitted to the Commission. The rates should be for hypothetical 10 MW, 20 MW, and 40 MW gas-fired, non-dispatchable projects with 100% capacity factors. The rates would be non-binding on the utility and would serve only as an approximation of rates for similar projects. Alternatively, utilities may forego publishing hypothetical rates if they can provide, within 10 working days of receiving a request, approximate rates based on IRP model runs.

Rate Quotations

Before a developer requests a rate quotation from a utility, Staff recommends a meeting be held between the utility and the developer to discuss details of the project and to discuss the process for calculating rates. Once a request for binding rates is made, Staff contends the utility should respond to the request within 30 days. In order to receive a firm quotation, the developer must be able to provide the utility with the following information:

1. Developer name;
2. Proof of QF status (notice of self-certification will suffice);
3. Project location, and point of power delivery if the project is located outside of the state of Idaho;
4. Project size, including ambient conditions for this rating;
5. Capacity factor and proposed time shape of production;
6. Fuel source and mode and route of delivery;
7. Whether fuel supply is firm or non-firm and whether there are any constraints affecting its availability or dependability;
8. Proposed contract term (final term — length and timing — to be subject to negotiation);
9. On-line month and year;
10. Maintenance schedule;
11. Other factors affecting operation;
12. Wheeling utility(ies) between point of interconnection and point of delivery;
13. Expected delivered energy by month during heavy and light load hours;
14. Guaranteed minimum capacity.

If a project desires to be operated according to a negotiated schedule or dispatched under specific circumstances, the utility may request additional information as needed in order to provide an accurate rate quotation.

In response to a request for rates, Staff believes the utility should provide the difference in cost by year between the base case plan and the same plan with the QF included. Using an acceptable methodology, utilities should separate the annual differences in costs into capacity and energy components.

Actual contract terms should be negotiable between the utility and the developer, subject to the rules and guidelines set forth in this document. Rate quotations should be effective for a minimum of 120 days. Except for the signing of other QF contracts, the acquisition of other generating resources, or major discrete changes in load, under no other circumstances should the rate be changed during the 120-day period, even if changes occur in variables. When providing a rate quotation, utilities should be obligated to divulge whether any other rate quotation has been made for another project and is still within its 120-day effective period. In addition, utilities must agree to meet with the developer within 15 working days after the date on which the rate quotation is made.

Access to Utility Models

Utilities should be allowed to utilize any model they desire in calculating avoided costs, as long as the same model is used in the development of the utility's IRP. If the utility is required to sign a licensing agreement for use of the model that restricts its use to utility personnel only, then access to the model may be restricted to the Commission Staff, subject to restrictions of the licensing agreement. However, in order to minimize the "black box" effect created when rates are calculated by the utility using proprietary software, utilities must be willing to accommodate requests from developers and Commission Staff for a reasonable number of model runs for alternative project plans. The model runs must be meaningful and requested in support of negotiating a commercially viable contract. Staff recommends that no fee be charged by the utility for these model runs. Furthermore, utilities should have the obligation to assist developers in optimizing their projects so that developers maximize the value of their project to the utility's system. To do so is in the best interests of both the developer and the utility.

Seasonalized and On-Peak/Off-Peak Rates

Staff believes utilities should be permitted to continue to offer different rates for peak and off-peak hours, and to continue to seasonalize rates (where currently allowed for Idaho Power and Washington Water Power) using the same seasonalization factors allowed for projects smaller than 1 MW.

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on this 29th day of May, 1996, I served a true and correct copy of the within and foregoing SETTLEMENT STIPULATION, to the following individuals by the method indicated below, and addressed to the following:

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