Capitol Law Group, PLLC

C. Tom Arkoosh

www.capitollawgroup.com • tarkoosh@capitollawgroup.com

RECEIVED
2012 JUN 29 AM 8:37
IDAHO PUBLIC
UTILITIES COMMISSION

June 28, 2012

Idaho Public Utilities Commission
P.O. Box 83720
Boise, Idaho 83720-0074

Re: Our Client: Twin Falls Canal Company and North Side Canal Company
CLG File No. 6417.000

Dear Commissioners:

Enclosed please find an original and nine copies of the Rebuttal Testimony of Donald W. Schenbeck.

If you have any questions or comments, please do not hesitate to contact me.

Sincerely,

Capitol Law Group, PLLC

Lori Thomas

Lori Thomas
Paralegal to C. Tom Arkoosh

CTA/lbt
Enclosures

205 North 10th Street, 4th Floor, PO Box 2598, Boise, ID 83701-2598 • Tel: (208) 424.8872 • Fax: (208) 424.8874

RECEIVED

2012 JUN 29 AM 8:37

IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE
IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE COMMISSION'S REVIEW OF PURPA QF CONTRACT PROVISIONS INCLUDING THE SURROGATE AVOIDED RESOURCES (SAR) AND INTEGRATED RESOURCE PLANNING (IRP) METHODOLOGIES FOR CALCULATING PUBLISHED AVOIDED COST RATES	**Case No. GNR-E-11-03**

REBUTTAL TESTIMONY OF

DONALD W. SCHOENBECK

ON BEHALF OF

NORTHSIDE CANAL COMPANY

TWIN FALLS CANAL COMPANY

RENEWABLE ENERGY COALITION

June 28, 2012

CASE NO. GNR-E-11-03

REBUTTAL TESTIMONY OF
DONALD W. SCHOENBECK

CONTENTS

PREFILED REBUTTAL TESTIMONY OF DONALD W. SCHOENBECK

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Donald W. Schoenbeck. I am a member of Regulatory & Cogeneration Services, Inc. ("RCS"), a utility rate and economic consulting firm. My business address is 900 Washington Street, Suite 780, Vancouver, WA 98660.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS PROCEEDING?

A. Yes. I provided direct testimony in this proceeding on behalf of Northside Canal Company, Twin Falls Canal Company and Renewable Energy Coalition (collectively, "QF Companies"). This rebuttal testimony is being submitted on behalf of these same companies.

Q. WHAT TOPICS WILL YOUR TESTIMONY ADDRESS?

A. Following this introduction and summary, my rebuttal testimony is organized in three sections. First, I will address matters where I have altered or modified the recommendations set forth in my direct testimony from having reviewed the prefiled direct testimony and subsequent discussions with other parties in this proceeding. These issues have to do with the source of gas prices for use under the SAR and IRP methods, allowable updates under the IRP method and avoided capacity cost. The next section of this testimony will address issues where my position has not changed even after reviewing other party's thoughts on certain matters. These issues have to do with contract term, REC ownership, the eligibility cap for fixed price contracts and Idaho Power's proposed Schedule 74.

Finally, in the last section, I discuss an issue raised by another party that I had not addressed in my direct testimony. Specifically, Dr. Reading's proposal with regard to transmission network upgrades.

Q. PLEASE BRIEFLY SUMMARIZE YOUR RECOMMENDATIONS ADDRESSED IN THIS TESTIMONY.

A. First, regarding modifications to my prior direct testimony, I recommend the following:

> The Energy Information Administration's Annual Energy Outlook ("EIA AEO") forecast should be used as the source of gas prices under the SAR method and for any updates under the IRP method.
>
> In addition to gas prices and QF contracts, updates to the IRP method can include newly executed non-QF contracts with a term of at least five years and known customer specific load changes that in aggregate are at least 25 MWs.
>
> Avoided capacity cost recognition and pricing can be done as set forth in Staff's revised updated avoided cost EXCEL spreadsheet model ("Updated Avoided Cost Model version 2.0").

Second, I disagree with Staff's direct testimony where Staff advocates the following policy changes: (a) that the Commission authorize a maximum QF contract term of just five years under the IRP method, (b) that the seller is compensated for RECs under the IRP method, (c) that the eligibility cap for fixed published rates be maintained at just 100 kWs for wind and solar projects, and (d) Idaho Power's proposed QF curtailment tariff, Schedule 74, should be approved. For the reasons set forth in my direct testimony, and as further explained in this rebuttal testimony, the Commission should not adopt any of these proposals. I re-affirm my direct testimony in advocating that contracts should be offered for up to twenty years under either pricing method, REC ownership should be retained by the seller, the eligibility cap for fixed published prices should be 10 MW for all resource types and Schedule 74 should not be approved by the Commission.

Finally, Dr. Reading's testimony recommends that a QF be entitled to full recovery of construction contributions paid by the QF for network transmission upgrades. The QF Companies fully support Dr. Reading's recommendation on this issue.

II. MODIFIED RECOMMENDATIONS

Q. HAVE YOU REVIEWED THE DIRECT TESTIMONY OF THE NON-UTILITY PARTIES FILED IN THIS PROCEEDING IN MAY 2012?

A. Yes, I have.

Q. HAS THIS REVIEW ALTERED OR CHANGED ANY OF THE RECOMMNEDATIONS SET FORTH IN YOUR DIRECT TESTIMONY?

A. Yes. From having reviewed and considered the prefiled direct testimony of Staff and Dr. Reading and from having additional discussions with parties, I believe it is appropriate to modify three recommendations I made in direct testimony regarding the source of gas prices, what updates or changes should be allowed under the IRP method and how avoided capacity costs should be determined and priced.

Q. HOW DID THE PARTIES TESTIMONY INFLUENCE YOUR THINKING WITH REGARD TO GAS SOURCE?

A. Both Staff witnesses and Dr. Reading proposed using prices from the EIA AEO as had also been recommended by Avista under the SAR method, including any updates. (See Dr. McHugh pages 3-5, Mr. Sterling page 8, Dr. Reading page 19 and Mr. Kalich page 34) Based upon my further discussions, I believe all these parties are now in agreement that the specific price series to use would be the

Mountain division series for electric power ("EIA Forecast") as detailed by Dr. McHugh under the SAR method. (See Dr. McHugh page 5, lines 7–10). Given this consensus and my review of this source, I agree that the EIA Forecast achieves most of the objectives I was seeking in an independent third party source and can be used to determine avoided cost rates.

Q. ARE THESE PARTIES IN AGREEMENT THAT THE EIA AEO SHOULD BE USED FOR IRP UPDATES AS WELL?

A. No, I do not believe this is the case. Staff advocates that the utilities do not have to use the EIA AEO (see Mr. Sterling page 23, lines 1–6) while Dr. Reading appears to advocate that it could be used in the IRP update (see Dr. Reading page 26, line 15 to page 27, line 5). The Avista testimony did not specifically address IRP gas price updates.

Q. WHAT IS YOUR RECOMMENDED SOURCE OR METHOD FOR AN IRP GAS PRICE UPDATE?

A. I recommend the EIA AEO be used for IRP updates as well. I fully understand and expect that the utility will use its preferred method for deriving gas prices for its initial IRP filing. During the IRP development process, parties are generally provided the opportunity to examine and comment on many inputs including the gas price forecast. However, an IRP update does not allow for this opportunity. Consequently, I believe the Commission should require that any IRP update should use precisely the same gas price source as under the SAR update. Given that any IRP update will be in place for only one or two years, use of an independent third party source should not result in any rate payer harm while on the other hand it would eliminate any potential game playing by the utility regarding this most critical input variable.

Q. WHAT DID YOUR DIRECT TESTIMONY RECOMMEND WITH RESPECT TO ALLOWABLE IRP UPDATES?

A. My direct testimony recommended that only two items may be updated: the gas price forecast and the inclusion of any newly executed QF PPAs.

Q. HAVE PARTIES PROPOSED INCLUDING OTHER ITEMS FOR ALLOWABLE IRP UPDATES?

A. Yes. Staff is proposing that fuel price forecasts, load forecasts and any new long-term purchase or sale contract obligation can be updated (see Mr. Sterling pages 22-25). More specifically, Staff is proposing that fuel prices and load forecasts should be updated once per year and any new purchase or sale contract commitments made at least one year in advance and at least one year's duration should be included in an IRP update, whenever the commitment is made.

Q. WHAT ARE YOUR THOUGHTS REGARDING THE STAFF'S ALLOWABLE UPDATE ITEMS?

A. I previously addressed my concern about allowing the utility to make updates based on internally generated forecasts for items that have no impact other than to greatly complicate the QF PPA negotiation process and allow for potential game playing of the avoided cost determination. Under the Staff proposal, this could readily happen by a utility lowering an internally generated coal price forecast or load forecast in an IRP update. With regard to allowing non-QF purchase or sale contract commitments in the update, I believe Staff's proposed inclusion of utility wholesale purchase contracts with terms of such short duration does not allow a utility to actually avoid capacity. For these reasons, I disagree with these aspects of Staff's update proposal. However, I am willing to recommend additional IRP update items addressing both these areas as long as they can be readily verified and not subject to any possible manipulation.

Q. WHAT ADDITIONAL ITEMS WOULD YOU RECOMMEND COULD BE INCLUDED IN AN IRP UPDATE?

A. I recommend that customer specific known load changes of at least 25 MWs (up or down) be included as well as any executed non-QF purchase or sale contract commitments of at least 5 or more years in duration.

Q. WHY DID YOU SELECT 25 MWS AS THE VALUE FOR LOAD CHANGES?

A. There were three reasons. First, it is the size of the standard market energy trading amount. As such, this is at least one measure for considering it to be a meaningful amount. The second reason has to do with the granularity with which production simulation models can produce meaningfully different results. Very modest load changes simply do not have a material impact on the result. Finally, load changes of this magnitude could well be reported and widely known even prior to the IRP update. This will facilitate the verification of the load change I believe is critical to minimizing disputes over the IRP update.

Q. MUST THE KNOWN LOAD CHANGE BE JUST A SINGLE CUSTOMER?

A. No. The 25 MW value can be an aggregated value from the departure, addition or expansion of several customers but it must be known and measurable. It cannot be a projection of load changes for a given customer class or sub-class from updating typical load forecast input assumptions.

Q. WHY DO YOU DISAGREE WITH THE STAFF PROPOSAL TO ALLOW UTILITY WHOLESALE PURCHASES WITH A TERM OF JUST ONE YEAR TO BE INCLUDED IN IRP UPDATES?

A. Allowing such market-based wholesale purchases with short terms in the IRP process does not eliminate the utility's need for capacity. PPAs with terms of just one, two, three or even four years are shorter than the typical time it takes to plan for and build a resource to meet a capacity deficit position. Consequently, the only effect of including PPAs with this short of duration in the IRP update would be to artificially lower the avoided capacity costs included in a QF PPA. This is inappropriate. However, I must emphasize that the non-QF PPAs I am recommending be allowed in the IRP update must be fully executed and have received Commission approval.

Q. BASED ON THIS REASONING, WOULD YOU AGREE THAT QF PPAS WITH TERMS LESS THAN FIVE YEARS DO NOT AVOID CAPACITY EITHER?

A. Yes, I would, ***provided that*** the Commission elects a reasonable QF PPA contract term in this proceeding. If non-QF power purchase contracts less than five years duration are not included in the IRP calculation of avoided costs, and the Commission requires utilities to sign QF contracts with terms up to 20 years, then I agree that QF PPAs with terms less than five years should not receive any avoided capacity payment or credit. On the other hand, if the Commission adopts the Idaho Power and Staff proposals to limit the maximum contract term to just five years, than avoided capacity costs should be included in the contractual prices because the QF and the utility are limited to this restrictive term.

Q. HOW HAVE YOUR RECOMMNEDATIONS CHANGED WITH REGARD TO AVOIDED CAPACITY COST ALLOCATION AND PRICING?

A. I believe that my recommendations to determine capacity need, allocation and pricing based on the results of a loss of load or unserved energy analysis is analytically superior to the existing methods employed by the utilities and Staff. However, I am readily aware that the results from such a probabilistic "black box" simulation can be subject to and sensitive to certain critical assumptions used in the analysis including inter-balancing area market availability. In addition, from discussions with Staff, including the examination of Staff's revised avoided cost EXCEL spreadsheet model ("Updated Avoided Cost Model version 2.0"), my primary concern with Staff's avoided capacity need determination has been addressed. Accordingly, I find Staff's revised model a simple, transparent and straightforward approach to determine capacity need, allocation and pricing.

III. NO CHANGES TO PRIOR RECOMMENDATIONS

Q. HAS YOUR REVIEW OF SOME OF THE PARTIES' TESTIMONY IDENTIFIED AREAS OF SIGNIFICANT DISAGREEMENT WITH YOUR DIRECT TESTIMONY?

A. Yes. Staff has accepted four utility proposals which I continue to oppose. These are: (i) that IRP priced contracts be limited to a maximum term of just five years, (ii) that RECs are deemed transferred to the purchasing utility under the IRP method,(iii) that a fixed price eligibility cap of just 100 kW apply to wind and solar resources, and (iv) that Idaho Power's proposed Schedule 74 for curtailment of QF generation be adopted. In large part, I have addressed the reasons why each of these proposals is inequitable, inappropriate and unfair in my direct testimony. I will limit my rebuttal testimony to specific points raised by Staff that I did not previously address.

Q. WHAT COMMENTS DO YOU HAVE WITH REGARD TO STAFF'S MAXIMUM FIVE YEAR CONTRACT TERM FOR IRP BASED CONTRACTS?

A. I find Staff's proposal to allow a maximum 20 year contract term under the SAR based method but only a maximum five year term under the IRP based method quite troubling. As stated in my direct testimony, a 20 year term is fair and appropriate. A five year term is not. It appears the crux of Staff's proposal is that the IRP contract term should be used "*to control the pace of PURPA development*" as set forth on page 29 of Mr. Sterling's testimony. Staff claims this control is needed because the power "*is not needed to serve customers*" and the depressed economy "*strain customers' ability to pay.*" Of course, we are all sympathetic to the economic woes the Pacific Northwest has been experiencing for some time. However, Staff must acknowledge that avoided costs are set such that the ratepayer is indifferent as to whether the power came from a QF PPA or the alternative resource.

Staff's testimony does state that when the Commission had previously imposed a maximum contract term of just five years from September 1996 to May 2002, QF development all but ceased as only one contract was executed during this period. (See Mr. Sterling, pages 27-28) While Staff asserts this was attributable to many factors, one of the significant factors was low natural gas prices, a condition that is present today as well. The ability to finance and recover capital costs based on the avoided costs proposed in this proceeding with today's gas prices is impossible over a five year period. Just has had occurred in 1996 to 2002, adoption of a maximum five year contract term will not "*control the pace*" of QF development above the fixed price eligibility cap but, rather, it will end it.

Q. IS THERE ANOTHER FACTOR THAT WILL BE CONTROLING THE PACE OF QF DEVELOPMENT?

A. Yes. Most parties to this proceeding are advocating no avoided capacity costs should be paid during periods of sufficiency. If this is adopted by the Commission, this feature will naturally control the pace of QF development without having to put in place a totally unreasonable five year contract term.

Q. WHAT IS STAFF'S POSITION WITH REGARD TO ENVIRONMENTAL ATTRIBUTES INCLUDING RECS?

A. The Staff believes the Commission should decide the question of REC ownership. For contracts under the IRP method, Staff asserts the cost is included in computing the avoided cost rates and therefore the utility should be entitled to the RECs. (See Mr. Sterling, page 46, lines 6-20) Under the SAR method, Staff's testimony states the utility should pay an additional amount "if it wished to own the RECs." (See Mr. Sterling, page 46, line 21 through page 47, line 8)

Q. DO YOU AGREE WITH STAFF'S ASSERTION THAT THE COSTS OF RECS ARE INCLUDED IN THE AVOIDED COST RATES DERIVED UNDER THE IRP METHOD?

A. No. Staff's logic is dependent upon the assertion that renewal resources are reflected in the utility resource plans and therefore are implicitly within the resulting avoided costs under the IRP method. This assertion is simply not correct. Earlier in the testimony, Staff acknowledges that under the utility IRP proposals "*capacity and energy values are calculated independently*" of each other. (See Mr. Sterling, page 17, lines 13-19). Under both the Idaho Power and Staff proposals, the capacity value is based on a SCCT and ***not*** the costs of the renewable resources in the utility's preferred portfolio. Under both the Staff and Idaho Power proposals, energy costs are derived from the incremental cost or market price of short-term energy. The resources supplying this energy are gas-fired or coal fired resources. These resources do not generate any RECs. As the resources used to derive the avoided costs under the IRP method do not produce RECs and Staff has proposed no incremental adjustment to the resulting IRP avoided costs, the REC ownership right should stay with the seller under the IRP method.

Q. DO YOU AGREE WITH THE STAFF POSITION THAT UTILITIES SHOULD HAVE TO PAY FOR REC OWNERSHIP UNDER THE SAR METHOD?

A. Yes, I do. If the REC market was liquid and transparent, it would make sense to provide a REC purchase option under the published fixed rates for QFs choosing to transfer (sell) RECs to the utility. However, it has been my experience that the REC market is illiquid and not transparent. Because of this market situation, I believe the fairest approach for all parties (QF, utility and ratepayers) is to simply allow the seller to retain the ownership of any associated RECs and all other environmental attributes. As noted in my direct testimony, this is my recommendation under both IRP and SAR methods.

Q. DO YOU HAVE ANY COMMENTS REGARDING STAFF'S SUPPORT FOR CONTINUING THE 100 KW PUBLISHED RATE ELIGIBILITY CAP FOR WIND AND SOLAR RESOURCES?

A. Yes. Staff's reasoning is based on the continuing existence of a financial incentive to game play through the disaggregation of resource capability. No party to this proceeding has objected to requiring annual gas price updates under both the SAR and IRP methods. If these updates are done simultaneously, I believe any financial incentive to disaggregate will be eliminated as the avoided energy costs should be very close under either method. Under these circumstances, a uniform eligibility cap across all technologies should be re-instated by the Commission. As explained in my direct testimony, I recommend this cap be 10 MW. I would also not that this is a significant reduction from the previous 10 <u>average</u> MW cap and a substantial reduction in size, moving from average to nameplate capacity.

Q. DO YOU HAVE ANY COMMENTS REGARDING STAFF'S SUPPORT OF IDAHO POWER'S PROPOSED SCHEDULE 74?

A. No. Staff has not provided any additional arguments that I need to address. For all the reasons stated in my direct testimony, the Commission should not approve the Idaho Power proposed schedule.

IV. ISSUES RAISED BY OTHER PARTIES

Q. DID YOUR REVIEW OF THE PARTY TESTIMONY RAISE ANY NEW ISSUES YOU HAD NOT ADDRESSED?

A. Yes. Dr. Reading's testimony recommended certain transmission and interconnection policy matters which I had not previously addressed. (See Dr. Reading pages 66 and 67). The essence of one of Dr. Reading's recommendations is that the Commission should mirror the FERC pricing standards for customer contributions in aid of construction for interconnection costs. The FERC policy calls for the payment of all costs up to the point of interconnection to be borne by the project developer. The cost of facilities beyond this point ("network upgrades") however are initially funded by the project developer but are eventually refunded by the transmission provider. On the other hand, Idaho Power's Schedule 72 ("Interconnection to Non-Utility Generation") provides for only a limited upgrade refund based upon another generator using the same network upgrade facilities and this "vested interest" refund right expires after just five years.

Q. IS THERE A BASIS FOR THE DIFFERENCE IN POLICIES BETWEEN A FERC REGULATED INTERCONNECTION AND A QF INTERCONNECTED DIRECTLY TO ITS BUYER?

A. Yes, there can be. In cases where a FERC interconnection is required, the interconnected QF (or possibly the purchaser) must pay for wheeling the power across the local transmission provider's system. In the case where the QF is directly connected to the purchasing utility (who is also the transmission provider), no such ongoing wheeling payments are required. Differences in policy can also arise simply from having differing views on who benefits from the system upgrade. FERC generally views network upgrades as providing a system benefit for all users of the network. From this perspective, then, it is equitable for all users to pay for the upgrade. Other parties have the prospective that the network upgrade is not providing any system benefit and that it would not be needed but for the QF. These parties argue that the QF should be responsible for paying for all network upgrades.

Q. WHICH PERSPECTIVE DO YOU AGREE WITH?

A. I agree with FERC's perspective. Network upgrades that allow power to be delivered to loads should be paid for by the loads and not the QF. In my view, this "levels the playing field" with utility owned generation. Certainly, Idaho

Power's customers are paying the network transmission costs to deliver power from Bridger to Boise and all other Idaho Power owned resources. These customers are even paying all the interconnection costs associated with these utility-owned assets as well (costs up to the interconnection point with the transmission network). The FERC prospective should be used to determine the costs that should be borne by QFs in Idaho as well. The QF Companies fully support Dr. Reading's recommendation and ask the Commission to adopt and employ the FERC interconnection policy in Idaho whereby network upgrades should be paid for by the users of the transmission system.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.