BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

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

DIRECT TESTIMONY OF DR. CATHLEEN M. MCHUGH

IDAHO PUBLIC UTILITIES COMMISSION

MAY 4, 2012

Q. Please state your name and business address for the record.

A. My name is Cathleen McHugh. My business address is 472 West Washington Street, Boise, Idaho.

Q. By whom are you employed and in what capacity?

A. I am employed by the Idaho Public Utilities Commission as a Utilities Analyst.

Q. What is your educational and professional background?

A. I received a Bachelor of Science degree in Economics and Applied Math from the University of Idaho in 1995. I received a Ph.D. in Economics from Duke University in 2005 with primary fields in Public Economics and the Economics of Education and with secondary fields in Econometrics (statistics applied to economics), Applied Microeconomics, and the History of Economic Thought.

While at Duke University, I taught the undergraduate introductory course on econometrics several times and served as a teaching assistant for the graduate introductory course on econometrics.

Between July 2005 and September 2009, I was employed by the Center for Naval Analyses (CNA) as an analyst. My duties there included devising and estimating econometric models for use in military manpower analysis. In this capacity, I co-wrote 17 different publications and

and presented my work at a number of conferences. In October 2009, I transitioned to a position as a CNA Field Representative where I provided analytic support directly to a United States Marine Corps Lieutenant General and his Command. I remained at this position until joining the IPUC in August 2011.

My current duties at the Commission include data analysis, modeling, resource planning, rate design, cost of service, and other duties as assigned for electric, gas, and water utilities.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to recommend updates to the current Surrogate Avoided Resource (SAR) model.

Q. Will you summarize your recommended changes to the model?

A. I recommend:

a) Using a forecast of natural gas prices from the Energy Information Administration's ("EIA") Annual Energy Outlook report in place of a forecast from the Northwest Power and Conservation Council (NWPCC). I recommend this change because the EIA report is updated more frequently than the NWPCC report. I further

propose that the EIA forecast be updated in the SAR model no later than July 1st of each year.

b) Taking the energy and/or capacity needs of a utility into consideration in calculating avoided costs. An earlier version of the SAR model did this by using the "first deficit year" concept.

c) Using resource-specific values for determining capacity payments.

d) Allowing for avoided costs to reflect the costs of transmission and loss in periods when the utility is in surplus.

Natural gas price forecast

Q. What is the source for the current SAR model's forecast of natural gas prices?

A. Pursuant to Order No. 30480, the current SAR model uses the latest available Northwest Power and Conservation Council's (NWPCC) 20-year forecast of natural gas prices. For years beyond those included in this forecast, the model predicts natural gas prices using exponential growth based on the last ten years of the NWPCC forecast.

Q. What are the main differences between this forecast and the forecast of natural gas prices from the EIA's Annual Energy Outlook?

A. With regards to the SAR model, there are two differences between the forecasts of note – the frequency of updates and the geographic focus of the updates.

Q. How frequently is the NWPCC forecast updated? What is its geographic focus?

A. The NWPCC is directed to review its regional power plan forecast at least every five years per the Pacific Northwest Electric Power Planning and Conservation Act. The 1st Power Plan was adopted in 1983. Subsequent plans were adopted in 1986, 1991, 1998, 2005, and, most recently, 2010. Included in the development of this plan is a forecast of natural gas prices.

The NWPCC forecast of fuel prices can be updated independently of the regional plan; in fact, it was revised in 2011 to reflect "a fundamental shift in expectations about future natural gas supplies." However, there is no set timeline for these types of updates.

The NWPCC forecast is a regional forecast for the Pacific Northwest (Washington, Oregon, Idaho, and Montana). The forecast includes prices for natural gas delivered to either the west side of the region (west-side delivered) or the east side of the region (east-side delivered). The current SAR model uses the estimate for east-side delivered.

Q. How frequently is the EIA forecast updated?

What is its geographic focus?

A. The EIA forecast is updated each spring. It provides forecasts of natural gas prices for all Census divisions of the United States. Idaho falls in the Mountain division (Montana, Idaho, Wyoming, Nevada, Utah, Colorado, Arizona, and New Mexico). The specific forecast I recommend using is found in the supplemental tables for regional detail, Table 18: Energy Prices by Sector and Source for the Mountain division/Natural Gas price for Electric Power. This is the delivered fuel price. It should be noted that Avista recommended using the same forecast but for the Pacific division (Washington, Oregon, California, Alaska, and Hawaii). The forecast I propose be used is included as Exhibit No. 301.

I have included both the forecasted real price and the forecasted nominal price. In the SAR model, I use the forecasted nominal price, which eliminates the need to adjust the forecast by any inflation rate.

Q. Can you compare the two different forecasts?

A. In Exhibit No. 302, I graph four different forecasts of natural gas prices. The first (denoted with circles) shows the most current NWPPC East-Side Delivered forecast. This forecast only extends to 2030 so I also include the estimates that would be used to extend it to 2035. These estimates are titled IPUC Estimates based on

NWPPC data (the line with diamonds). The next forecast is the 2011 EIA forecast for the Mountain region (the line with triangles). Both this forecast and the NWPCC forecast were released around the same time – the EIA forecast was released in the spring of 2011 while the NWPCC forecast was released in summer of 2011. These two forecasts are very similar especially if one excludes the first two years. During the entire period, the forecasts never vary by more than $0.35 and, after the first two years, they never vary by more than $0.15. The IPUC estimates are considerably higher than the EIA forecast – they average almost $0.60 higher.

The final forecast shown is the EIA forecast released in the spring of 2012 (the line with squares). Comparing this forecast to the earlier two forecasts illustrates how much can change in a single year. This forecast is always lower than the NWPCC forecast – at one point, it is $0.61 lower. On average, it is $0.32 lower than the NWPCC forecast. In contrast, the 2011 EIA forecast was, on average, $0.07 higher than the NWPCC forecast.

In periods of price fluctuations, relying on a forecast that is even a year old can dramatically change the avoided cost computation. In periods of downward trending prices, the computed cost would be too high if

one relied on a dated forecast. Conversely, in periods of upward trending prices, the computed avoided cost would be too low. Therefore, Staff supports use of the EIA forecast as it will reflect the most current understanding of future natural gas prices.

Considering Need in Calculating Avoided Costs

Q. How did prior versions of the SAR model take into consideration a utility's need for energy in setting the avoided cost rates?

A. A prior version of the SAR model used a "first deficit year" concept. This prior version of the model differed from the current SAR model in that the avoided costs were set equal to "surplus energy rates" for years in which the utility had surplus energy (years prior to the first deficit year). The surplus energy rate was based on wholesale energy rates and was set by Commission order. Avoided costs for years in which the utility was not in surplus were calculated as they are in the present SAR model.

Q. Why was the "first deficit year" concept abandoned?

A. At the time this was abandoned, Staff expressed concerns that determining the first deficit year was problematic *even though the underlying rationale for it was sound*. All together, Staff identified nine areas of

concern regarding the determination of the first deficit year. These concerns can be grouped in the following categories:

a) There exists too much discretion on the part of utilities to influence the results (Reasons 1, 3, 4). As noted by Avista witness Kalich, this is less true today than in 2002. All the electric utilities file biennual IRPs which are developed with input from the public, regulators, and other interested parties. Thus, irregular frequency (Reason 1), the reasonableness of planning assumptions (Reason 3), and the possibility of inaccurate load forecasts (Reason 4) can all be addressed in the IRP process.

b) The definition of the first deficit year is not clear (Reasons 2 and 5). At the time, it was not clear whether or not the first deficit year should be based on energy or capacity needs (Reason 2) or whether it should incorporate firm market purchases (Reason 5). The proposed updates take into consideration both energy and capacity needs so Reason 2 is no longer valid. Because it is based on the IRP, the proposed update is consistent with generally accepted IRP

methodology in how it treats firm market purchases.

c) Using the concept of the first deficit year really does not matter in terms of avoided rate calculation (Reasons 6 and 8), and,

d) Market prices can be extremely volatile (Reason 9). Both of these reasons had more to do with the implementation of the concept rather than the concept itself.

Q. Are you instituting the "first deficit year" concept exactly as it had been instituted prior to 2002?

A. No. The model I recommend identifies years in which a utility is deficient in energy, in capacity, or both. This is based on information from each utility's most recent IRP. If a utility is deficient in energy, then the QF would receive an energy payment. If a utility is not deficient in energy, then the QF would receive an energy payment minus costs for transmission and losses. The previous SAR model did not adjust for transmission and losses.

In the recommended model, capacity payments are specific to the resource used by the QF. If a utility is deficient in capacity, then the recommended model examines whether the utility is deficient in summer only, in winter only, or in both seasons. If the utility is deficient in

only one season, then the model bases a resource-specific capacity payment on the ability of that resource to contribute during the deficient season's peak. However, if a utility is deficient in both seasons, then the model bases the resource-specific capacity payment on the ability of that resource to contribute during both seasons' peaks. This is the same methodology suggested by Avista.

To clarify matters, consider canal drop QFs. Canal drops can contribute 100 percent of their capacity during the summer peak and 0 percent of their capacity during the winter peak. If a utility is only capacity deficient during the summer, then a canal drop QF receives the full capacity payment. However, if a utility is capacity deficient in only the winter or in both the summer and winter, then the canal drop receives no capacity payment. Allowing capacity payments to differ by resource should encourage development of QFs with characteristics of value to the utilities (such as QFs that provide generation during peak hours).

Staff concurs with Avista witness Kalich on the basis for capacity payments. In his direct testimony, page 21, lines 5 through 9, Mr. Kalich states:

> *It is not fair to pay one resource with a low capacity factor and an equivalently high on-peak contribution the same per-MWh payment as second base load plant*

operating with a relatively high capacity factor all year round. Using the method, the low capacity factor resource would receive much lower total compensation even though the resource provided the same on-peak capacity benefit to the utility.

Q. What is the energy payment based on?

A. It is based on the cost of fuel and variable operations and maintenance.

Q. Avista proposes that energy rates during surplus periods be reduced to account for transmission wheeling costs and losses that the utility would encounter in delivering the QF's energy to a market hub. Do you believe that such reductions in energy rates are justified?

A. Yes, I do. If the energy truly is not needed by the utility to meet its own obligations, then it must sell that surplus energy in the market. Wheeling charges and transmission losses are real costs that must be borne by the utility; therefore, it seems appropriate for those costs to be attributed to the QF that is supplying the surplus energy.

I recommend that if the Commission believes it is appropriate to reduce energy rates during utility surplus periods then Idaho Power and PacifiCorp also be directed to propose comparable amounts using an approach similar to that proposed by Avista.

Q. Do you have projected rates based on your proposed changes to the SAR model?

A. Yes. These are included as Exhibit No. 303. It should be noted that the results are preliminary and reflect Staff's understanding of the utilities' positions as of the time of filing this testimony. The calculated rates could change during the course of this case due to corrections, revised fuel forecasts, and changes in long-term commitments.

For every resource, the rates for Idaho Power and PacifiCorp are higher than the rates for Avista. This largely reflects the fact that Idaho Power and PacifiCorp are deficient in both energy and capacity earlier than Avista.

The rates for canal drop projects are considerably higher for Idaho Power and PacifiCorp compared to other resources primarily because canal drop projects offer capacity during peak summer hours and their capacity payment is spread out over relatively few total hours. This also occurs in the IRP model as discussed by Staff witness Sterling. Canal drop and solar projects have lower rates for Avista compared to the other two utilities because Avista is generally capacity deficient in the winter when neither of these resources produces much energy.

Wind projects receive the lowest rates among the different types of resources for all three utilities. This reflects wind's low on-peak capacity factor.

Q. Have you reviewed the SAR model submitted by Avista? Do you have any comments on it?

A. Yes, I have reviewed the model and I believe there are several minor errors in the model.

First, the Avista model assumes an integration charge of $6.50 per MWh for wind and solar projects. However, pursuant to Order No. 30488, the correct integration charge for Avista and Idaho Power is calculated as a percentage of the levelized avoided cost rate with the percent applied dependent on the amount of wind/solar on the system. It cannot exceed $6.50 per MWh but it can fall below that amount. Pursuant to Order No. 31021, the integration charge for PacifiCorp is $6.50 per MWh.

The second minor issue is that the Avista model levelizes the integration charge. The integration charge should be applied annually to the levelized amount. The third minor issue is that the Avista model fails to properly levelize capital costs.

Q. Does this conclude your direct testimony in this proceeding?

A. Yes, it does.

Report Annual Energy Outlook 2012 Early Release
Scenario ref2012 Reference case
Datekey d121011b
Release Date January 2012
ref2012.d121011b

18. Energy Prices by Sector and Source
(2010 dollars per million Btu, unless otherwise noted)
Mountain - 08
Sector and Source

		Electric Power 9/		
	Distillate Fuel Oil	Residual Fuel Oil	Natural Gas	Steam Coal
2009	15.10	10.40	4.49	1.65
2010	18.67	11.91	5.02	1.57
2011	23.19	11.77	4.16	1.67
2012	23.36	11.33	3.98	1.69
2013	22.21	25.97	3.91	1.71
2014	23.39	27.11	3.76	1.76
2015	24.32	27.98	3.98	1.83
2016	24.69	28.24	4.01	1.85
2017	25.17	28.66	4.18	1.89
2018	25.39	28.90	4.39	1.90
2019	25.62	29.06	4.55	1.91
2020	25.83	29.21	4.67	1.92
2021	26.04	29.28	5.00	1.93
2022	26.28	29.53	5.34	1.96
2023	26.53	29.71	5.52	1.99
2024	26.67	29.82	5.60	2.03
2025	27.04	29.96	5.63	2.06
2026	27.29	30.00	5.80	2.09
2027	27.47	30.14	6.02	2.11
2028	27.65	30.34	6.10	2.13
2029	27.90	30.45	6.10	2.15
2030	28.10	30.37	6.15	2.18
2031	28.49	30.23	6.30	2.19
2032	28.72	29.98	6.48	2.21
2033	29.12	30.39	6.64	2.24
2034	29.58	30.68	6.82	2.26
2035	29.94	30.88	7.05	2.28

Exhibit No. 301
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Prices in Nominal Dollars

		Electric Power 9/		
	Distillate Fuel Oil	Residual Fuel Oil	Natural Gas	Steam Coal
2009	14.93	10.28	4.44	1.64
2010	18.67	11.91	5.02	1.57
2011	23.65	12.01	4.24	1.70
2012	24.05	11.67	4.09	1.74
2013	23.10	27.02	4.07	1.78
2014	24.75	28.68	3.97	1.87
2015	26.21	30.16	4.29	1.97
2016	27.14	31.04	4.41	2.04
2017	28.19	32.11	4.68	2.11
2018	28.99	33.00	5.01	2.17
2019	29.84	33.84	5.30	2.22
2020	30.70	34.71	5.55	2.28
2021	31.57	35.50	6.06	2.34
2022	32.51	36.53	6.60	2.42
2023	33.49	37.51	6.97	2.52
2024	34.36	38.42	7.22	2.61
2025	35.54	39.38	7.41	2.71
2026	36.60	40.23	7.78	2.80
2027	37.57	41.22	8.24	2.89
2028	38.56	42.31	8.51	2.97
2029	39.67	43.29	8.67	3.06
2030	40.72	44.02	8.92	3.15
2031	42.07	44.65	9.31	3.23
2032	43.21	45.10	9.74	3.32
2033	44.60	46.55	10.17	3.42
2034	46.14	47.85	10.64	3.52
2035	47.52	49.02	11.19	3.62

9/ Includes electricity-only and combined heat and power plants whose primary business is to sell electricity, or electricity and heat, to the public.

Btu = British thermal unit.

Note: Data for 2009 and 2010 are model results and may differ slightly from official EIA data reports.

Sources: 2009 and 2010 prices for motor gasoline, distillate fuel oil, and jet fuel are based on prices in the U.S. Energy Information Administration (EIA), Petroleum Marketing Annual 2009, DOE/EIA-0487(2009) (Washington, DC, August 2010).
2009 residential and commercial natural gas delivered prices: EIA, Natural Gas Annual 2009, DOE/EIA-0131(2009) (Washington, DC, December 2010). 2010 residential and commercial natural gas delivered prices: EIA, Natural Gas Monthly, DOE/EIA-0130(2011/07) (Washington, DC, July 2011).
2009 and 2010 industrial natural gas delivered prices are estimated based on: EIA, Manufacturing Energy Consumption Survey and industrial and wellhead prices from the Natural Gas Annual 2009, DOE/EIA-0131(2009) (Washington, DC, December 2010) and the Natural Gas Monthly, DOE/EIA-0130(2011/07) (Washington, DC, July 2011).
2009 transportation sector natural gas delivered prices are based on: EIA, Natural Gas Annual 2009, DOE/EIA-0131 (2009) (Washington, DC, December 2010) and estimated State taxes, Federal taxes, and dispensing costs or charges.
2010 transportation sector natural gas delivered prices are model results.
2009 and 2010 electric power prices based on: EIA, Monthly Energy Review, DOE/EIA-0035(2010/09) (Washington, DC, September 2010). 2009 and 2010 E85 prices
2009 and 2010 electric power sector natural gas prices: EIA, Electric Power Monthly, April 2010 and April 2011, Table 4.2, and EIA, State Energy Data System 2009, DOE/EIA-0214(2009) (Washington, DC, June 2011).
2009 and 2010 coal prices based on: EIA, Quarterly Coal Report, October-December 2010, DOE/EIA-0121(2010/4Q) (Washington, DC, May 2011) and EIA, AEO2012 National Energy Modeling System.
2009 and 2010 electricity prices: EIA, Annual Energy Review 2010, DOE/EIA-0384(2010) (Washington, DC, October 2011).
2009 and 2010 E85 prices derived from monthly prices in the Clean Cities Alternative Fuel Price Report.
Projections: EIA, AEO2012 National Energy Modeling System run ref2012.d121011b.

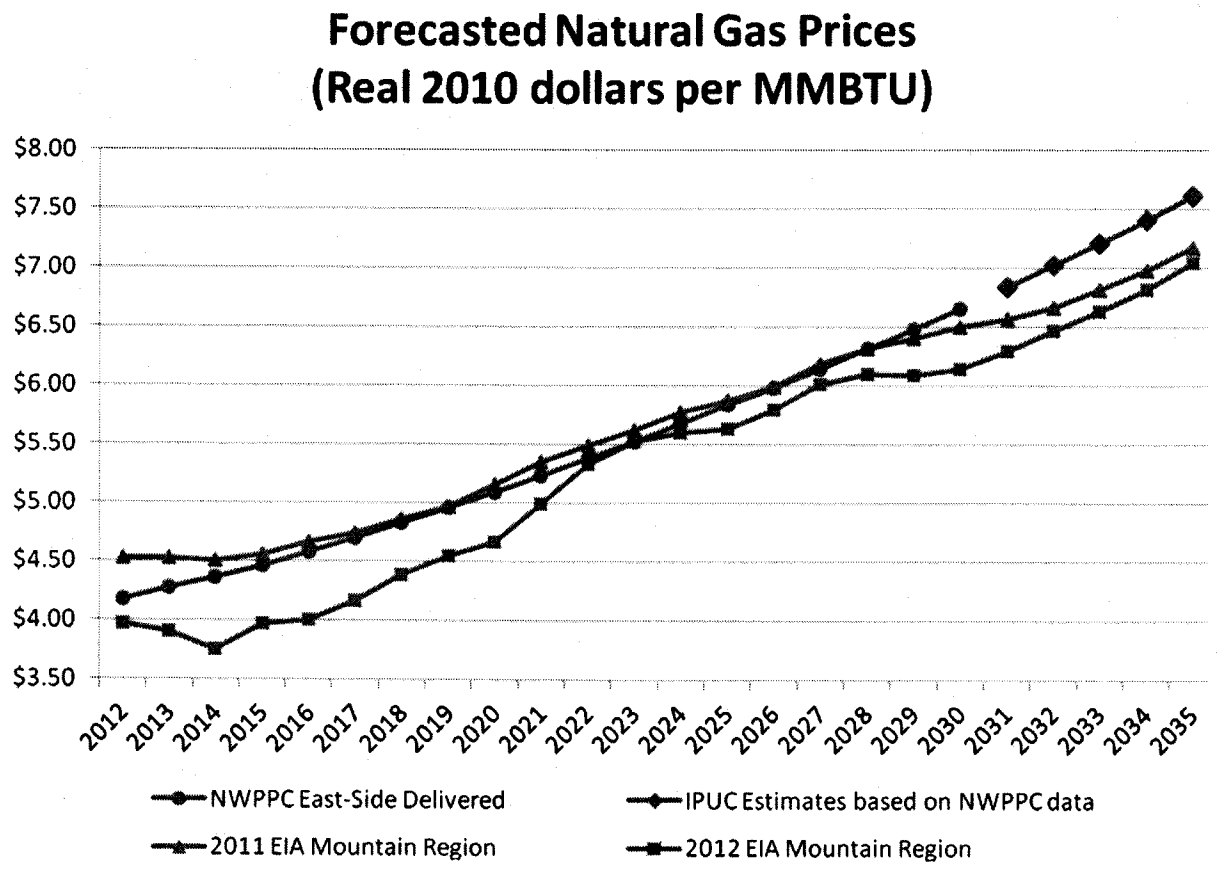

Exhibit No. 302
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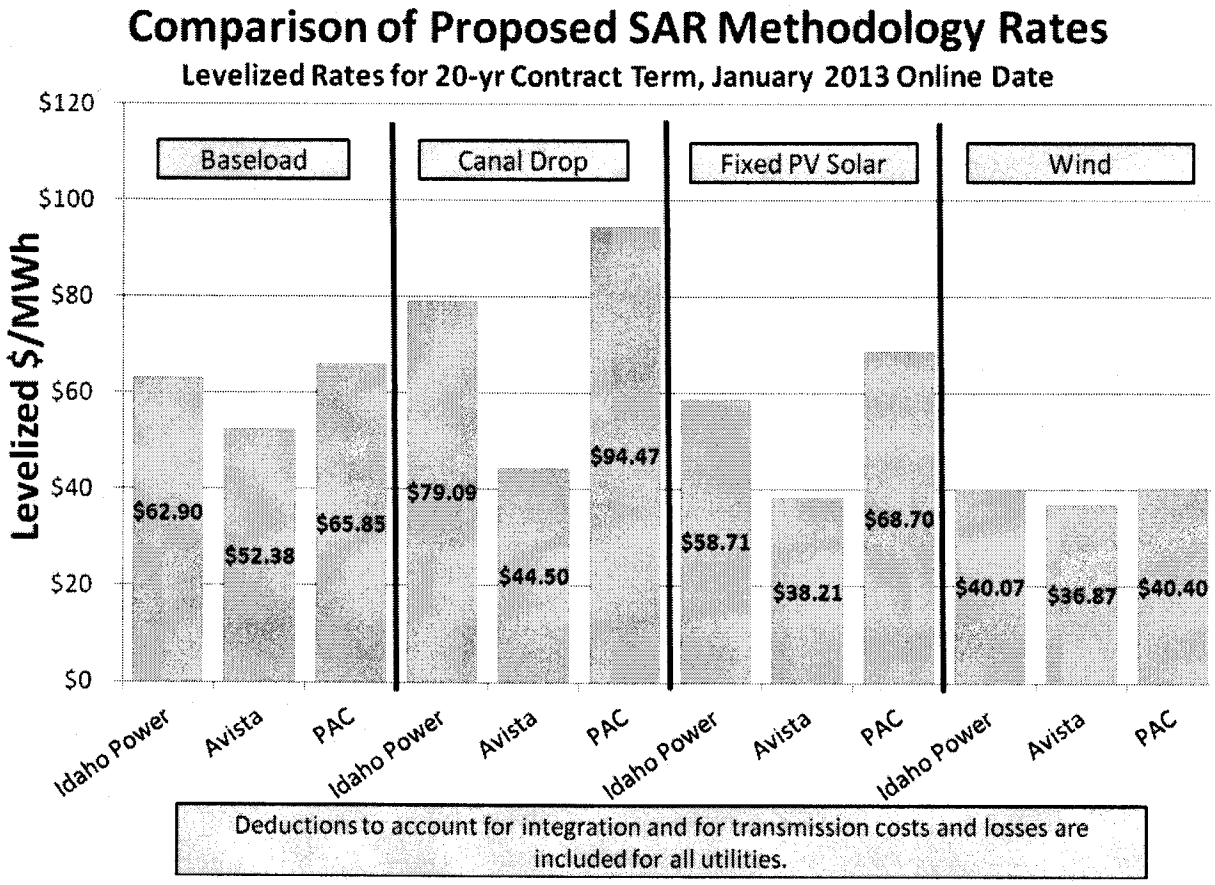

Exhibit No. 303
Case No. GNR-E-11-03
C. McHugh, Staff
5/04/12

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 4TH DAY OF MAY 2012, SERVED THE FOREGOING **DIRECT TESTIMONY OF DR. CATHLEEN M. MCHUGH,** IN CASE NO. GNR-E-11-03, BY MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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