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April 22, 2015

Jean J. Jewell, Secretary
Idaho Public Utilities Commission
P.O. Box 83720
Boise, Idaho 83720-0084

Re: Case No. IPC-E-15-01; AVU-E-15-01 and PAC-E-15-03

Dear Mrs. Jewell:

Enclosed for filing in the captioned case please find an original and nine copies of ***IDAHO IRRIGATION PUMPERS ASSOCIATION, INC. DIRECT TESTIMONY OF ANTHONY J. YANKEL.*** Also attached is an original and 9 copies of the "Confidential" pages as well as a thumb drive as required for this filing.

Thank you for your assistance.

Very truly yours,

ERIC L. OLSEN

ELO:tl
Enclosures
c: Service List

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S PETITION TO MODIFY TERMS AND CONDITIONS OF PURPA PURCHASE AGREEMENT	CASE NO. IPC-E-15-01
IN THE MATTER OF AVISTA CORPORATION'S PETITION TO MODIFY TERMS AND CONDITIONS OF PURPA PURCHASE AGREEMENT	CASE NO. AVU-E-15-01
IN THE MATTER OF ROCKY MOUNTAIN POWER COMPANY'S PETITION TO MODIFY TERMS AND CONDITIONS OF PURPA PURCHASE AGREEMENT	CASE NO. PAC-E-15-03

IDAHO IRRIGATION PUMPERS ASSOCIATION, INC.

DIRECT TESTIMONY

OF

ANTHONY J. YANKEL

April 23, 2015

Q. Please state your name, address, and employment.

A. I am Anthony J. Yankel. I am President of Yankel and Associates, Inc. My address is 29814 Lake Road, Bay Village, Ohio, 44140.

Q. Would you briefly describe your educational background and professional experience?

A. I received a Bachelor of Science Degree in Electrical Engineering from Carnegie Institute of Technology in 1969 and a Master of Science Degree in Chemical Engineering from the University of Idaho in 1972. From 1969 through 1972, I was employed by the Air Correction Division of Universal Oil Products as a product design engineer. My chief responsibilities were in the areas of design, start-up, and repair of new and existing product lines for coal-fired power plants. From 1973 through 1977, I was employed by the Bureau of Air Quality for the Idaho Department of Health & Welfare, Division of Environment. As Chief Engineer of the Bureau, my responsibilities covered a wide range of investigative functions. From 1978 through June 1979, I was employed as the Director of the Idaho Electrical Consumers Office. In that capacity, I was responsible for all organizational and technical aspects of advocating a variety of positions before various governmental bodies that represented the interests of the consumers in the State of Idaho. From July 1979 through October 1980, I was a partner in the firm of Yankel, Eddy, and Associates. Since that time, I have been in business for myself. I have been a registered Professional Engineer in the states of Ohio and Idaho. I have presented testimony before the Federal Energy Regulatory Commission (FERC), as well as the State Public Utility Commissions of Idaho, Montana, Ohio, Pennsylvania, Utah, and West Virginia.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Idaho Irrigation Pumpers Association, Inc. (Irrigators).

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

A. My testimony will address:

* Supporting Idaho Power's initial request for a limitation on new PURPA contracts to a term of two years. I do not view this as a long-term solution to the glut of PURPA contracts that plague Idaho Power, but it is a good stop-gap measure to give the Company and the Commission an opportunity to correct problems with the present avoided cost model assumptions.
* My critique of Idaho Power's Exhibit 6 that attempts to illustrate the problems of must-run and must-take power on the Company's system. I contrast what is shown on Exhibit 6 with the manner in which the system is actually operated.
* I provide a review and contrast of how the Company's avoided cost model assumptions differ from the manner in which costly resources are actually utilized, while making sales-for-resale at substantially lower prices.
* My ultimate recommendation is that new PURPA contracts be limited to a term of two years and during that two year timeframe, the Company and the Commission develop a more accurate avoided cost methodology.

Q. What is your overall understanding of the purpose of the Qualifying Facilities ("QF") under the Public Utility Regulatory Policies Act of 1978 ("PURPA")?

A. PURPA attempted to encourage the development of cogeneration and small power production facilities which were known as QF's. The purpose of these PURPA projects was to help the Country become energy independent by utilizing cogeneration and small power production facilities as a means of capturing energy, but for PURPA, may have been wasted. For more than 20 years Idaho Power and the Commission have been successful in developing these cogeneration and small production facilities.

However, with the advent of new wind and solar technology, the general principles behind the PURPA generation resources has become lost. We are no longer talking about cogeneration and small power production facilities, but installations/facilities that rival any utility generation project. Rates paid to PURPA facilities were meant to be just and reasonable to a utility's customers. In this case, Idaho Power appropriately points out that the present situation with PURPA facilities is inappropriately causing rates to the customers to go up and are thus, no longer just and reasonable.

Q. What is the present situation with PURPA facilities and the Idaho Power system?

A. The present situation is well described by Idaho Power in this case. The capacity level of PURPA facilities that are presently on the system or that have signed contracts, far out-weigh the Company's ability to economically integrate them into the system. There are two basic problems—must-take contracts and price. Given the level of the present facilities and signed

contracts on the system, the Company will run into many times when it will simply have too much capacity and will need to choose between curtailing its own must-run facilities or the PURPA must-take contracts. The situation is further compounded by the fact that the prices being paid to these PURPA facilities is usually higher than the running cost of any of the Company's facilities. Backing down Idaho Power's facilities (to the point of must-run levels), in order to allow more generation from these PURPA facilities simply means that the customers will be paying more. The most egregious problem is that there have been times in the past when Idaho Power has had to pay other utilities to take its excess power.

Q. Why are you supporting Idaho Power's request to limit the term of future contracts to just two years, when you indicate that the fundamental problem is the must-take provision as well as the price?

A. I support the reduction of new contract terms to two years as a stopgap measure. I assume that it will take at least two years to work out the complexities of what has gone wrong and how to correct it. If new PURPA contracts were priced appropriately, Idaho Power would either not have a glut of such facilities on its system now (and proposed to get much worse), or it would be able to sell and/or deliver this energy in a manner that would not adversely impact its customers. It is going to take some time to determine how to best integrate new PURPA facilities into the system without exacerbating an already bad situation. If solutions can be developed in two years, then they can be incorporated into the new/renewed contracts. If the new contract terms coming out of this case were for five years and solutions were developed in two years, Idaho Power (and its customers) would have to wait an additional three years before finding some

relief from a bad situation that has the potential to make things worse with each new contract that is signed.

Q. Do you support limiting all new PURPA contracts to a two year term?

A. No. I support only limiting the new solar and wind contracts to the two year term. These are the contracts for intermittent power that got us into trouble in the first place. The original purpose of the PURPA contracts was for "cogeneration and small power production". These are the types of facilities that may require long-term contracts in order to get financing. PURPA was designed to stimulate cogeneration and small power production and not utility size projects. I support the continuation of long-term contracts for new cogeneration and small power production facilities.

IPCo's Exhibit 6 Compared To Actual Operation

Q. Idaho Power's Exhibit 6 portrays the first week of each of 24 months of estimated system load on an hourly basis compared to the company's must-run resources, must-take PURPA generation and must-take non-PURPA power purchase agreements. Does that exhibit demonstrate the problems Idaho Power could incur with respect to too much must-take capacity on the system?

A. Yes. Idaho Power's Exhibit 6 depicts the problem of having more must-take capacity on the system (in addition to its own resources) than system load. However this exhibit should be considered for illustrative purposes only. The system is far more involved than simply assuming forecasted load and minimum must-run and must-take capacity levels.

Q. Idaho Power's Exhibit 6 demonstrates that Idaho Power not only has excess must-take capacity from PURPA generation, but there is often excess capacity from only its own must-run generation as well. Is that a problem?

A. No. First, it must be remembered that this exhibit is for illustrative purposes only. The excess must-run capacity shown in Idaho Power Exhibit 6 does not reflect any additional sales or obligations of Idaho Power. Thus, most of the extra Company-owned capacity on the system can be absorbed by other than system customers. Very simply, Idaho Power's Exhibit 6 is for illustrative purposes, and does not necessarily reflect how the system is actually operated.

Second, based upon Exhibit 6, the Company states[1] that 14% of the time there would be excess capacity on the system, if one only included IPCo's must-run generation and the generation from its own PPA's. I have worked on Idaho Power cases for over 35 years and have never heard of a time where the Company had too much operating capacity on an ongoing basis. Yes, there are times when generation exceeds system load, but during these times energy is sold off-system or generation is simply taken off-line.

Q. With respect to excess must-run capacity, how does the actual system operation differ from the illustration in Idaho Power Exhibit 6?

A. On page 5 of 25 of Idaho Power Exhibit 6, is portrayed the "Forecasted Must Run or Take Generation" for the first week of April 2016 compared to the "Idaho Power Forecasted

[1] See testimony of Company witness Allphin at page 10.

Load" (system only). As would be expected, April is the month with the most must-run capacity compared to system load. During most of the forecasted hours for April 2016 (primarily the last two hours of each day), the Idaho Power must-run capacity (excluding IPCo's own must-take PPA's, PURPA excluding wind and solar, PURPA wind, PURPA solar under contract, and the 885 MW of proposed PURPA solar) is well above the forecasted load. Based upon the assumptions contained on page 5 of that Exhibit, one would expect that April would be the month when most of the curtailments due to excess capacity on the system would occur.

Idaho Power indicated[2] that over the timeframe May 2011 through December 2014, there were 21 reliability curtailments of PURPA generation because of an over-generation position on the system. Of these 21 curtailments, [redacted] during the month of April. However, compared to the magnitude of the potential resource load/capacity imbalance demonstrated on Exhibit 6 for April 2016, these [redacted] curtailments only represented [redacted] of the number of hours of curtailment that occurred during these 21 events[3].

Q. With respect to excess must-run capacity during other months, how does the actual system operation differ from the illustration in Idaho Power Exhibit 6?

A. Unlike April, the graphs for October and November of 2016 on Exhibit 6 pages 11 and 12 portray the forecasted system load well in excess of Idaho Power's own must-run generation. In fact the graph for October portrays no hours where the minimum must-run levels of the Company's resources (plus IPCo must-take PPA) even approaches the level of the forecasted system load. Additionally, with all of the resources (Company and none Company) listed on

[2] See testimony of Company witness Grow at page 21 and response to Simplot Request to Produce 6a.

[3] [redacted]

Exhibit 6 there was only approximately 15 hours out of the 168 total hours in that week where the system load is less than the summation of all must-take capacity including:

* IPCo's must-run hydro and coal generation,
* IPCo's own must-take PPA's,
* PURPA excluding wind and solar,
* PURPA wind, PURPA solar under contract, and
* 885 MW of proposed PURPA solar.

The graph for November portrays essentially the same thing. There are no hours in which the must-run IPCo facilities plus IPCo's must-take PPA's exceeds the forecasted system load. Even including the PURPA resources, (including solar under contract and the 885 MW of proposed solar) there are only approximately 25 hours when the system load is less than the summation of all must-run and must-take capacity. In other words, under today's conditions, where the solar under contract and the proposed solar does not yet exist, October and November are two months where Idaho Power should have minimal problems with excess capacity on the system.

In contrast to the forecasted data in Exhibit 6, of the actual 21 curtailments that occurred between May 2011 and December 2014, [redacted] occurred during the months of October and November[4]. However, compared to the minimal potential resource load/capacity imbalance (in the future with added wind and solar) demonstrated on Exhibit 6 for October and November, 2016, these [redacted] historic curtailments represented [redacted][5] of the number of hours of curtailment that occurred during these 21 events—under conditions of less PURPA wind and solar capacity than

[4] See confidential Response to Simplot Request 6d.
[5] Confidential response to Simplot Request 6d—[redacted]

what is listed in Exhibit 6. [redacted] curtailments lasted longer than all [redacted] actual events combined that occurred during the months of April[6].

Q. What does this comparison of Exhibit 6 and Idaho Power's actual curtailments indicate about the need for reliability curtailments of PURPA generation on the IPCo system?

A. It means that Exhibit 6 does not give any quantifiable insight into the need of the Company to call for reliability curtailments of PURPA generation because of excess must-take capacity on the system. Exhibit 6 is a good illustration, but it is only an illustration and tells nothing about the operation of the system. Looking only at Idaho Power's own must-run hydro and coal, plus Non-PURPA must-take power purchases (without the addition of PURPA generation–purchases), the Company states[7] that Exhibit 6 demonstrates that over the 2016—2017 period, system load will be exceeded 14% of the time. By comparison, the actual 21 curtailments that occurred during the May 2011 through December 2014 (44 months), amounted to only [redacted] of that timeframe.

Q. What should be concluded from a comparison of Idaho Power's Exhibit 6 and the actual level of curtailments that have had to be taken on the system over the 44 month period under review?

A. It should be recognized that Idaho Power's Exhibit 6 is a good illustration of the problems the Company is facing, but it is not an accurate reflection of how the Company operates

[6] Confidential response to Simplot Request 6d—[redacted]

[7] See Company witness Allphin's testimony page 10 line19—25.

[8] Confidential response to Simplot Request 6d--[redacted].

in the real world. If the Company's modeling assumption do not reflect actual operation, then inappropriate conclusion may be drawn from the models—of most concern in this case is the avoided cost price that comes out of the Company's IRP model. If the IRP model assumption do not recognize the way that IPCo uses Term purchases and Sales, Beginning of Month ("BOM") purchases and sales; and Day-Ahead purchases and sales, to balance its load, its avoided cost pricing will be too high. The Company uses Term, BOM, and Day-Ahead activity to hedge its supply in order to keep costs down. If the Company's IRP model assumptions do not reflect this same logic, the resulting avoided costs will be too high.

Q. As opposed to the general comparison that you just made between Idaho Power's illustrative operation data and its actual level of curtailments over the recent 44 month period, can you demonstrate more specifically how the assumptions of must-run capacity in Idaho Power's Exhibit 6 compare to actual operations when a curtailment was called?

A. Yes. One of the 21 curtailments called by Idaho Power during this 44 recent month period occurred during [redacted] It lasted [redacted] and spanned two days. The curtailment lasted over all of the light load hours between these two days as well as [redacted] additional hours.

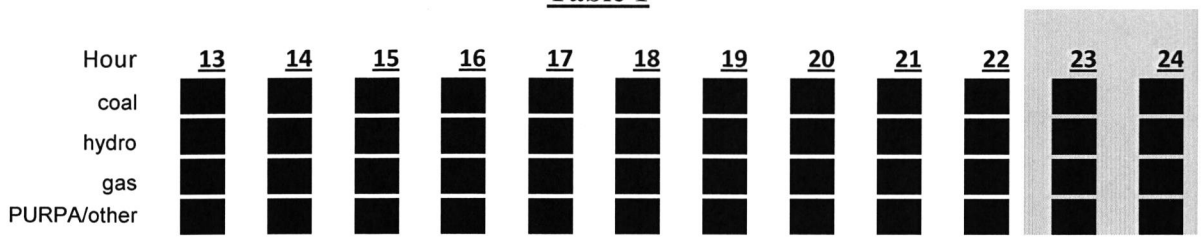
Table 1 below lists the capacity figures from the last 12 hours of the first day when this particular curtailment took place.[10] The "gray areas" reflects the first of the light-load hours (for the last two hours of the day) when the curtailment was taking place. The capacity figures listed are significantly higher than those that are represented as must-run and must-take capacity levels

[9] Confidential response to Simplot Request 6d—the curtailment occurred on [redacted]

[10] Data from the date and times listed from the confidential response to Irrigation Request 10.

found in Idaho Power's Exhibit 6. A reliability curtailment was taking place during these two light-load hours when generation was significantly above the minimum levels listed on IPCo's Exhibit 6.

Table 1



For example, the capacity coming out of the coal facilities ([redacted]) is significantly higher than the "must-run" level of 266 MW listed on the graphs of Idaho Power's Exhibit 6. Although there is a definite drop in coal generation from what occurred during the midafternoon hours, the drop is nowhere near the "must-run" level of 266 MW.

The capacity coming out of the hydro facilities is similarly higher than that used to establish Idaho Power's Exhibit 6 page 9 for the last two hours of the first day. Measuring the height of the "must-run" level depicted for "hydro plus coal" in Exhibit 6, it can be estimated that the "must-run" capacity for these two sources is 700 MW. With coal generation taking up 266 MW of this total, this leaves 434 MW as the "must-run" minimum level for hydro generation. The actual hydro generation was more than [redacted] greater than this minimum during these last two hours of the day when the curtailment was called.

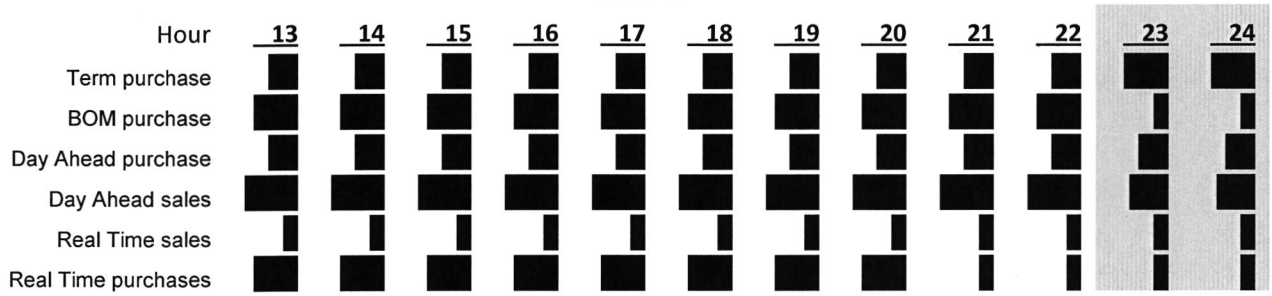
Of even more significance, the gas plants, because of their nature, are not forecasted to run during any of the minimum generation levels found on Idaho Power Exhibit 6. However, as seen on Table 1 above, the gas plants were operating in the [redacted] range during the last two hours of the day when the curtailment was called.

For completeness, Table 1 includes the amount of PURPA and other generation on the Idaho Power system during these same hours.

Q. How does purchase power and sales for resale fit into the mix of resources and requirements on the [redacted] day that you are addressing?

A. Purchase Power and Sales for Resale are listed for each of the same last 12 hours of that day on Table 2.[11]

Table 2



The Term purchases and Beginning of Month (BOM) purchases are all a part of the system balance, but they are set well ahead of the time when critical decisions need to be made regarding the need for curtailment because of excess capacity. Day-Ahead sales and purchases reflect some knowledge of what will occur during the following day. [redacted]

Real Time sales and purchases can definitely impact the excess capacity situation. [redacted]

[11] Id.

[redacted]

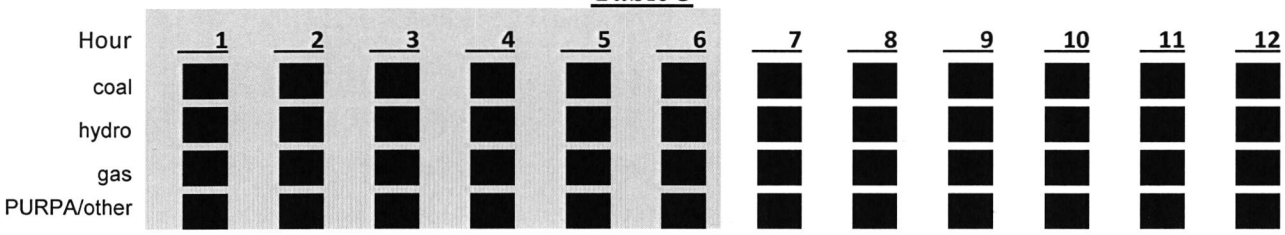
[redacted]

Q. Please continue to demonstrate how the assumptions of must-run capacity in Idaho Power's Exhibit 6 compare to actual operations during the second day when the curtailment in question was called?

A. As pointed out above, the curtailment in question lasted [redacted] and spanned two days. The curtailment lasted over all of the light-load hours between these two days as well as [redacted] hours. Like the first day addressed above, for the second day of the curtailment, I will primarily focus on what took place during light-load hours and contrast them with the rest of the hours in the first half of the second day.

Table 3 below lists the capacity figures from the first 12 hours of the second day when this particular curtailment took place[12]. The "gray areas" for the first six hours of the day reflect the remainder of the light-load hours when the curtailment was taking place. The significance of these first six hours of the day is that the capacity figures listed are very different than those that are represented as must-run capacity levels found in Idaho Power's Exhibit 6.

Table 3



[12] Id.

For example, the capacity coming out of the coal facilities ([redacted]) is significantly higher than the "must-run" level of 266 MW listed on the graphs of Idaho Power's Exhibit 6. Although the coal generation that occurred during the first six hours (light-load hours) is lower than the coal generation during the later morning hours, the drop is nowhere near the "must-run" level of 266 MW—in spite of the fact that a reliability curtailment was taking place.

The capacity coming out of the hydro facilities is similarly higher than that used to establish Idaho Power's Exhibit 6 page 9 for the first four hours of the second day. It can be seen that on the graph on Exhibit 6 page 9 that the height of the "must-run" level depicted for "hydro plus coal" is at the same height as the last two hours of the previous day, i.e., 700 MW. With coal generation taking up 266 MW of this total, this leaves 434 MW as the "must-run" minimum level for hydro generation. The hydro generation was about [redacted]% greater than this minimum during these first four hours of the second day when the reliability curtailment was called.

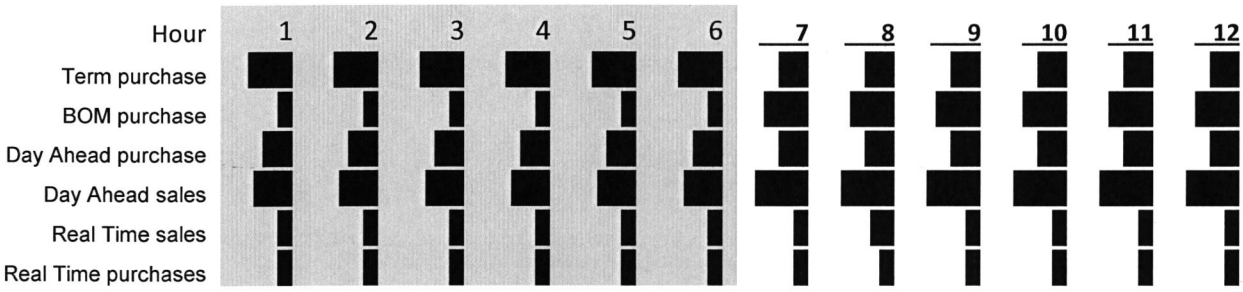
Of even more significance, the gas plants, because of their nature, are not forecasted to run during any of the minimum generation levels found on Idaho Power Exhibit 6. However, as seen on Table 3 above, the gas plants were operating in the [redacted] MW range during the first six hours of the second day when the reliability curtailment was called.

For completeness, Table 3 includes the amount of PURPA and other generation on the Idaho Power system during these same hours.

Q. How does purchase power and sales for resale fit into the mix of resources and requirements on the second day in [redacted] that you are addressing?

A. Purchase Power and Sales for Resale are listed for each of the first 12 hours of that day on Table 4.

Table 4



Once again, the Term purchases and Beginning of Month (BOM) purchases are all a part of the system balance, but they are set well ahead of the time when critical decisions need to be made regarding the need for reliability curtailments because of excess capacity. Day-Ahead sales and purchases reflect some knowledge of what will occur during the following day. The combined Day-Ahead transactions during these hours resulted in [redacted] the following day of excess capacity. For the particular hours in question, all of these non-Real Time transactions result in [redacted].

Real Time sales and purchases can definitely impact the excess capacity situation. [redacted]

Q. Does this comparison of Idaho Power's Exhibit 6, page 9 with an actual curtailment that occurred during August 2012 indicate that Idaho Power was operating its system inappropriately and/or it should not have curtailed PURPA load?

A. Absolutely not. At this time, I am assuming that Idaho Power operated its system during the time of this reliability curtailment to the best of its abilities—including the curtailment. Once again, this comparison shows is that there is a great deal of difference between many of the Company's modeling assumptions and the way the system works on an hour-to-hour basis.

Q. What is the significance to this case of the difference between modeling assumptions and hour-to-hour operations?

A. The modeling indicates that there are potential problems regarding excess capacity that cannot be addressed by backing down units below a must-run level. However, the large differences between the model results and actual operation demonstrates the limited ability of the model assumptions to reflect actual system operation, and more importantly, actual system costs. This inability of the Company's model assumptions to reflect actual system operation and actual system cost is particularly important to this case, because if the avoided costs that are developed to be paid to PURPA generators are inaccurate, so will the inducement to build these projects. If the IRP model assumptions do not recognize the way that IPCo uses Term purchases and Sales, Beginning of Month ("BOM") purchases and sales; and Day-Ahead purchases and sales, to balance its load, its avoided cost pricing will be too high. The Company uses Term, BOM, and

Day-Ahead activity to hedge its supply in order to keep costs down. If the Company's IRP model assumptions do not reflect this same logic, the resulting avoided costs will be too high.

A far better way to control the growth of PURPA generation on the Idaho Power system is not to reduce the terms of the contracts, but to develop avoided cost model assumptions that more accurately reflect the operation of the system. These avoided cost model assumptions must not only recognize the glut of PURPA generation that is presently on the system, but how the system actually operates today. Having a model assumption that assumes that new/additional PURPA generation will replace the Company's owned resources is simply invalid. This may have been an acceptable assumption when the amount of PURPA generation on the system was small, but today this assumption is not only causing operation problems, but is resulting in significantly higher prices for ratepayers.

PURPA Generation Replacing The Highest Cost Resource

Q. Can you give any other examples of how the actual operation of the system may differ from the assumptions used in the IRP model to develop avoided costs?

A. Yes. It is my understanding that a prime assumption used in the IRP model is that, except for system operating limitations, the least expensive options in the resource stack will be used to supply load. Very simply, this means that a more expensive resource will be backed-off, if a cheaper resource is available. However, there are times when the actual operation does not strictly follow this rule. I assume that the Company is operating its system at the lowest cost it can, given the minute-to-minute and hour-to-hour balancing of loads and resources that are

required. However, if the Company's IRP model assumptions, as a whole, do not accurately reflect the minute-to-minute and hour-to-hour operation of the Company, one cannot expect the resulting avoided cost that comes out of the model to be accurate.

Q. Can you demonstrate how Idaho Power's actual operations differ from the general principle that only the lowest cost resources should be utilized?

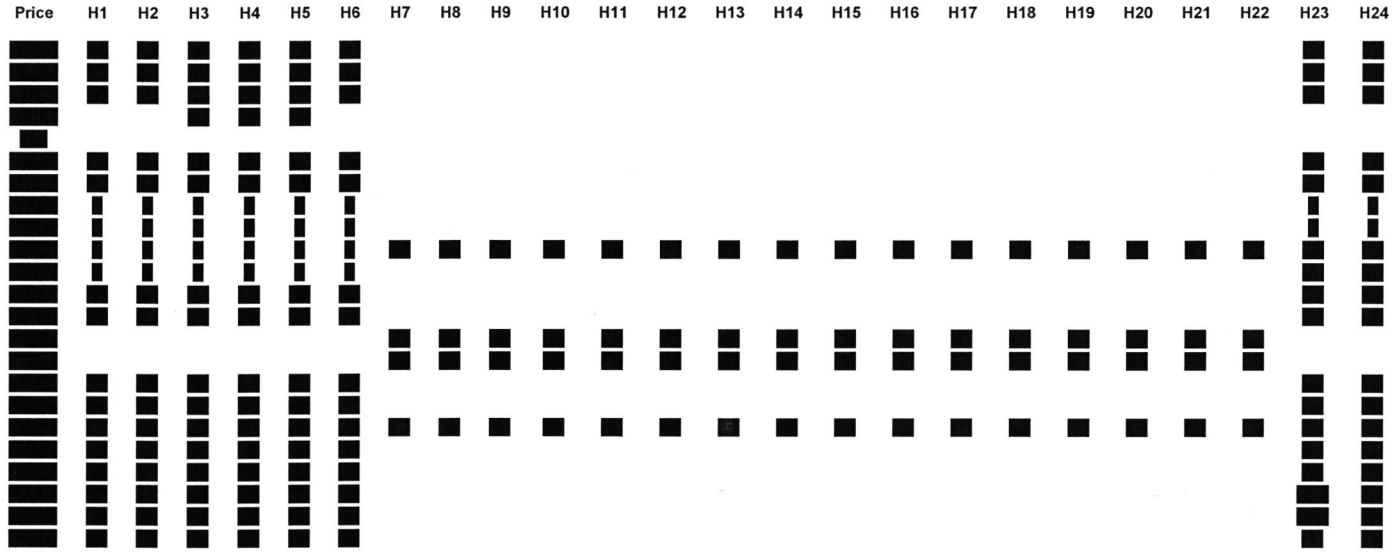
A. Yes. As a component of the concept of using the lowest cost resources first, it is generally agreed that when a sales-for-resale is made, the price received for the energy should be equal to or above the highest cost unit/resource operating. In other words, it is assumed that if the sale were not made, then the highest priced resource could be backed-off by the quantity of the energy sold. Of course, this does not apply to energy coming from PURPA projects or if there is some operational limitation in effect at the time.

By way of example, during actual operations Idaho Power does in fact sell energy off-system at prices lower than the cost of its most expensive operating resource (and often below the cost of more than just its highest cost operating resource). In order to demonstrate this, I have constructed Table 5. In [redacted] Idaho Power started Langley Gulch on [redacted] and ran it constantly (24x7) [redacted]. Generally speaking, Langley Gulch ran [redacted] generally at a stable level during each period. Table 5 lists the hours [redacted] when the weighted-average price[13] received for day-ahead sales-for-resale fell well below the cost of running Langley Gulch

[13] Data from the date and times listed from the confidential response to Irrigation Request 10.

($35.0 per MWH)[14], and in many cases below the cost of operating some of the Company's coal plant: Valmy at $49.6 per MWH[15]; Boardman at $32.1 per MWH[16]; and Jim Bridger at $28.6 per MWH[17].

Table 5



Q. Please further describe what is contained on Table 5.

A. Table 5 indicates for the hours between [redacted] whether or not the price received for day-ahead sales-for-resale was less than the cost of operating Langley Gulch. The first column lists the date and the first row lists the hours in each day. The second column lists the average-weighted price received for the "low priced" sales-for-resale for a given day and hour being addressed here. An "X" marks the hour during a given day when Langley Gulch was operating and when sales-for-resale have occurred at the weighted-average price listed in Column 2. When there is an "XX", Langley Gulch is operating as well as one other gas generator. When there is an "XXX", all three of the Idaho Power's gas units are operating (note

[14] Idaho Power's 2013 FERC Form 1 page 402.1 for Langley Gulch.
[15] Idaho Power's 2013 FERC Form 1 page 403 for Valmy.
[16] Idaho Power's 2013 FERC Form 1 page 402 for Boardman.
[17] Idaho Power's 2013 FERC Form 1 page 402 for Jim Bridger.

that Danskin operates at $54.3 per MWH and Bennett Mountain at $59.0 per MWH[18]). An "XV" indicates that Langley Gulch is operating and that Valmy is operating above minimum must-run level. No marking indicates that there were no sale-for-resale during that particular day and hour at the "low prices" listed in Column 2.

By way of example, [redacted]. The average-weighted price of the energy sold at this time was [redacted]. This price is well below the operating cost of Langley Gulch and Valmy (as well as Bridger and Boardman), which were both operating at the time. Sales-for-resale were sold at this weighted-average price of [redacted]. These hours are marked with a "XV".

By way of further example, the weighted-average price of the energy sold on [redacted]. On this day Valmy was operating at minimum levels during the first six hours so the table only displays an "X" for this time period. On this day, the sales-for-resale at the weighted-average price of [redacted]. Valmy was operating above minimum levels after the 6:00 a.m. hour. Because both Langley Gulch was operating and Valmy was operating above minimum levels after the 6 a.m. hour, these hours are marked with a "XV".

Q. What can be concluded from Table 5 with respect to the differences between the assumptions in the Company models for avoided costs and the way the Company actually operates its system?

[18] Idaho Power's 2013 FERC Form 1 page 403 for Danskin and Bennett Mountain.

A. As I pointed out above, I assume that the Company operates its system in order to minimize costs. Table 5 demonstrates that Idaho Power does not operate its system based upon the simplifying assumption that (absent certain operational constraints) the lowest cost resources will be used to supply load. Under this assumption in the model, the Company would not be selling power at prices significantly lower than the marginal cost to produce the energy. The model assumptions used to establish avoided costs must reflect how the Company actually operates and not rely upon general assumptions that ignore many of the realities of the system.

Conclusion and Recommendations

Q. What are your conclusions and recommendations?

A. From the above differences that I have pointed out, it is obvious that Idaho Power's models and modeling assumptions do not sufficiently reflect actual Company operations. Without the Company's model assumptions accurately reflecting actual system operation, it must be assumed that the models do not adequately predict avoided costs.

I recommend that the Commission limit the term of all future PURPA contracts to 2-years for all three of the major electric utilities operating in the Idaho. Hopefully, this will be sufficient time to review the modeling assumptions and the avoided costs of all three utilities. Assuming that adequate modeling assumptions can be put in place within two years, then it may be desirable to change the length of the term at that time. If adequate modeling cannot be put in place within two years, then the 2-year term should stay in place.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on this 23rd day of April, 2015 I served a true, correct and complete copy of the Idaho Irrigation Pumpers Association, Inc. Direct Testimony of Anthony J. Yankel to each of the following, via U.S. Mail or private courier, e-mail or hand delivery, as indicated below:

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