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June 13, 2005

Public Utility Commission of Oregon
Attn: Filing Center
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PO Box 2148
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Re: UE 167

Attention filing center:

Enclosed for filing please find the Staff Opening Brief in Docket No. UE 167, *In the Matter of the Application of Idaho Power Company for Authority to Increase its Rates and Charges for Electric Service to Customers in the State of Oregon.*

Thank you for your attention.

Very truly yours,

Stephanie S. Andrus
Assistant Attorney General

Enc.
c. Service list

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 167

In the Matter of the Application of Idaho Power Company for Authority to Increase its Rates and Charges for Electricity Service to Customers in the State of Oregon.	STAFF OPENING BRIEF

I. Introduction

The active parties to this docket, Idaho Power Company ("Idaho Power"), the Citizens' Utility Board ("CUB"), Oregon industrial customers of Idaho Power ("Industrial Customers") and staff of the Public Utility Commission ("staff") have resolved many of the issues raised by Idaho Power's request for a general rate increase by stipulated agreement.[1] The primary issue on which the parties do not agree is the appropriate level of net variable power costs (NVPC) to include in Idaho Power's revenue requirement. NVPC is Idaho Power's projected power supply expenses minus the projected revenues it would receive from selling surplus power that it generates into the wholesale market.

The parties generally agree as to the amount of power that Idaho Power would sell in the wholesale market under normalized conditions, but do not agree on the price at which Idaho Power would sell it. Staff, the Industrial Customers and CUB believe Idaho Power has significantly understated the prices at which it would make wholesale sales under normalized conditions, and thus, has significantly understated revenues that would offset its power supply expenses. The result of these understatements is a NVPC that is unreasonably and unrealistically high.

In this brief, staff explains the flaws in Idaho Power's modeling that result in Idaho Power's undervaluation of revenue it would receive from wholesale sales under normalized conditions and explains its (staff's) recommendation for determining NVPC for purposes of Idaho Power's revenue requirement. Further, staff addresses five other issues presented in this case that are not addressed in the Stipulation. These issues are

[1] Portland General Electric Company also intervened in this docket, but did not submit testimony and did not actively participate in settlement negotiations.

whether: 1) Idaho Power's Danskin plant should be included in rate base; 2) the Commission should adopt the Company's proposal for time-of-use rates for its industrial customers; 3) the Commission should adopt the Company's proposal for seasonal rates for residential customers; 4) Idaho Power's power supply in Oregon is sufficient; and 5) the Commission should order Idaho Power to work with interested parties to investigate the potential of integrating emergency generators into Idaho Power's system for additional generating capacity.

II. Background

This general rate case began in September 2004, when Idaho Power submitted an application for a general rate increase ("the Application"). In the Application, Idaho Power asked to increase its revenue requirement in the approximate amount of $4,418,908, which would equal a 17.52 percent overall increase. Idaho Power has implicitly modified the amount of the requested increase by entering into a stipulation with CUB, staff and the Industrial Customers. Idaho Power has stipulated that the appropriate rate increase for all revenue requirement items, excluding NVPC, is $3,048,000, which would equal a 12.09 percent increase. (Idaho Power/Staff/CUB/Industrial Customers/100, page 3.)[2]

The stipulation entered into by Idaho Power, staff, CUB and the Industrial Customers resolved issues related to rate of return, net to gross factor, known and measurable changes to rate base, cloud seeding costs, non-labor and A&G expense, employee incentive pay, payroll salary structure, wage and salary, Hells Canyon Complex legal costs, rate base additions, prepaid pension expense, marginal costs and

[2] This amount also does not include Danskin in ratebase. Whether Danskin should be included was not resolved by the Stipulation.

certain filing requirements and conservation.[3] For the reasons stated in the Joint Testimony supporting the Stipulation, staff recommends that the Commission adopt the Stipulation.

III. Argument.

a. NVPC

Idaho Power developed its proposed normalized NVPC of $47.7 million using a power cost model known as the AURORA model. Idaho made 76 model runs corresponding to 76 years of modified streamflow data, from years 1928 - 2003. Idaho Power first used the streamflow data to determine its annual and monthly hydroelectric generation under each of the 76 streamflow conditions given current flood control constraints, minimum flow requirements, and fish operating constraints. (Staff Exhibit 402.) Idaho Power then developed annual natural gas prices for each of the 76 streamflow conditions. (Staff Exhibits 401 and 405.) Using this information and other inputs, Idaho Power used the AURORA model to simulate the hourly economic dispatch of regional generating units to meet regional loads under each of the 76 streamflow conditions.[4]

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[3] At lines 5-6 of page 3 of the Joint Testimony supporting the Stipulation, the parties list "rate spread" as a resolved issue. (Idaho Power/Staff/CUB/Industrial Customers/100, page 3.) This statement is incorrect.

[4] Each of the 76 projections share a common set of assumptions, but also has its own unique set of assumptions. For example, each projection assumes the same Western System Coordination Council ("WSCC") load profile, uses the same set of parameters to describe regional generating units and transmission links and sets the hourly market-clearing electricity price equal to the variable cost of the last generating units needed to meet demand. However, each projection also has a unique set of assumptions. For example, each projection uses a unique hydro generation series and a unique natural gas price series. Idaho Power's model indicates what market-clearing electricity prices would be given current WSCC regional loads, current WSCC generating units, current WSCC transmission capabilities and given the particular set of hydro generation/natural gas price inputs. (Staff/300, Galbraith/4.)

At the regional level, the primary model output is hourly market-clearing electricity prices.[5] (Staff/403.) In other words, AURORA ostensibly indicates what market-clearing electricity prices would be in the region, given current Western System Coordinating Council ("WSCC") regional loads, current WSCC generating units, current WSCC transmission capabilities and individualized sets of hydro generation and natural gas inputs.

At the company level, the model outputs include fuel expense, purchased power expense, and surplus sales revenue. (Idaho Power/13). The company level outputs reflect the regional market-clearing electricity prices Idaho Power obtained using the AURORA model. Idaho Power combines these outputs to determine its NVPC.

Staff does not take issue with Idaho Power's projections of its normalized load-resource balance based on the 76 years of modified streamflows. Staff rejects, however, Idaho Power's market-clearing electricity and NVPC projections because the validity of these projections is impaired by Idaho Power's reliance on flawed natural gas price assumptions.

1. Idaho Power's generation exceeds its load.

Idaho Power owns generating resources that have the capacity to generate electricity in excess of what it needs to serve its retail load. On an annual basis, under average hydro conditions, the company projects that resources will exceed retail load by

[5] An hourly market-clearing price is the price where quantity supplied equals quantity demanded for that hour. Theoretically, in perfectly competitive markets, markets clear at a quantity where price equals marginal cost. The AURORA modeling methodology explicitly assumes perfect competition. AURORA sets the hourly electricity prices equal to the variable cost of the last generating units needed to meet demand.

321 average megawatts (MWa). 321 average MWs is equivalent to 20 percent of the company's annual normalized load.

Under the highest hydro condition, the Company projects a long position of 722 MWa. Under the lowest hydro conditions, the Company projects a short position of 107 MWa. Notably, for 62 of Idaho Power's 76 water year projections (82 percent), the annual position shows resources exceeding loads by more than 100 MWa. The surplus position that Idaho Power will enjoy under most water conditions, allows Idaho Power to make wholesale sales to reduce NVPC.

Because Idaho Power has significantly understated the price at which it would be able to sell its surplus generation in the wholesale market under normalized conditions, Idaho Power has significantly undervalued projected revenues from wholesale sales during the test period. When realistic prices are substituted for those used by Idaho Power in estimating NVPC for the test period, the revenues from Idaho Power's projected sales of excess generation exceed its projected generating costs, resulting in negative NVPC.

2. Idaho Power's projected market-clearing prices are unreasonably low.

Idaho Power witness Greg Said's direct testimony addresses the level of market prices that Idaho Power expected to see during the rate period. Inexplicably, the projected market prices Idaho Power relies on to project NVPC are significantly below those anticipated in Idaho Power's testimony. Mr. Said's testimony is as follows:

> Q: How have market prices of energy changed in the last ten years?
>
> A: Market prices for energy are generally higher than market prices ten years ago. In the UE 92 case [in 1995] it was assumed that the highest monthly market price that the Company might encounter would be $27 per MWh, which is equivalent to 27 mills per kilowatt-hour (KWh) or 2.7

> cents per KWh. Ignoring the run-up in market prices that occurred in the 2000-2001 time period, the Company has routinely seen market prices in the $40 to $50 per MWh price range during the last two drought years. It has been quite some time since the Company and the region experienced high water conditions, but if high water was to occur, I would expect that market prices would be significantly lower than the $40 to $50 per MWh range, but not as low as the $7 to $17 per MWh range expected to accompany high water conditions ten years ago. (Idaho Power/Exhibit 12T, Said/5.)

First, notwithstanding Mr. Said's testimony that the Company has *routinely* seen market prices in the $40-$50 range in the previous two drought years, Idaho Power's proposed normalized NVPC is based on market-clearing electricity prices with only:

- 22.9 percent of Mid-Columbia on-peak prices *for the lowest water condition* above $40 per MWh;
- 6.3 percent of Mid-Columbia off-peak prices for the lowest water condition above $40 per MWh;
- 2.1 percent of Mid-Columbia on-peak prices for the 25th percentile water condition above $40 MWh; and
- 1.0 percent of Mid-Columbia off-peak prices for the 25th percentile water condition above $40 MWh. (Staff/200, Galbraith/7.)

In comparison, the Dow Jones Mid-Columbia Daily Firm Electricity Price Indexes for 2003 and 2004 show a high frequency of prices above $40:

- 46.3 percent of the on-peak prices in 2003 were above $40 per MWh;
- 15.9 percent of the off-peak prices in 2003 were above $40 per MWh;
- 74.0 percent of the on-peak prices in 2004 were above $40 per MWh; and
- 42.1 percent of the off-peak in 2004 were above $40 per MWh. (Staff/200, Galbraith/6.)

Second, notwithstanding Mr. Said's testimony that Idaho Power would not expect prices as low as $7-$17 per MWh to accompany high water years, 80 percent of Idaho Power's projected daily Mid-Columbia on-peak prices for the highest water condition are below $20 MWh. (Staff/200, Galbraith/8.)

Third, Idaho Power even understates market electricity prices under average hydro conditions. Given average hydro conditions, Idaho Power projects an annual average daily Mid-Columbia on-peak price of $23.91 per MWh. Its highest projected daily on-peak price under average hydro conditions is $30.83 MWh. (Staff/200, Galbraith/9.) In contrast, during the period of January 1, 2004 through June 30, 2004, Idaho Power's forward price curve for calendar year 2005 delivery shows on-peak prices in the $39 per MWh to $51 per MWh range. (Staff/200, Galbraith/9.)

These comparisons, which are also discussed in staff's testimony, establish that Idaho Power's projected market-clearing prices are unrealistically low. This conclusion is also compelled by testimony presented by CUB. According to CUB, average wholesale on-peak power prices projected by the Northwest Power and Conservation Council (the Council) for the Southern Idaho Region are to be between $44 per MWh and $58 per MWh in 2006. The Council projects off-peak prices to in Southern Idaho to bounce between $33 per MWh and $52 per MWh through 2008. (CUB/100 Jenks-Brown/3.) As CUB states in its testimony, these projections belie Idaho Power's assertion that on average, the Company will sell its excess power for around $21 per MWh.

As already noted, and as explained more fully below, Idaho Power's understated projections for market-clearing prices during the test year stem from Idaho Power's flawed assumptions regarding natural gas prices.

3. Idaho Power's natural gas price inputs are unrealistically low.

As explained above, Idaho Power developed annual natural gas price inputs corresponding to each of the 76 streamflow conditions. These gas prices are generally intended to be annual average gas prices at the Henry Hub in Louisiana, adjusted to incorporate the basis differential between Henry Hub and Idaho Power's system. Idaho Power's annual natural gas prices at Henry Hub:

- average $3.88 per MMBTU across the 76 hydro conditions;
- range from $2.36 to $3.07 per MMBTU across the best hydro conditions; and
- range from $4.61 to $5.38 per MMBTU across the worst hydro conditions.

(Staff/200, Galbraith/11.)

In comparison, the Natural Gas Intelligence (NGI) Daily Henry Hub Price Index:

- averaged $5.47 per MMBTU in 2003; and
- averaged $5.89 per MMBTU in 2004. (Staff/200, Galbraith/11.)

In further comparison, forward-looking NYMEX natural gas prices at Henry Hub for the 2005 delivery strip were routinely priced above:

- $4.70 per MMBTU during 2003; and
- $6.25 per MMBTU during 2004.

Notwithstanding the fact that staff's testimony included these comparisons demonstrating that Idaho Power's inputs for its AURORA model for gas prices are unrealistically low, Idaho Power did not present evidence attempting to show that in fact its reliance on these inputs was reasonable. In absence of such evidence, it is unclear why Idaho Power believes it is appropriate for the Commission to nonetheless rely on the output of the AURORA model. Idaho Power bears the burden of proof in this proceeding. In absence of persuasive evidence demonstrating the integrity of the market-clearing prices, and NVPC, modeled by Idaho Power using the AURORA model, the Commission should reject them.

4. Idaho Power's power cost normalization methodology is conceptually flawed.

Even assuming that Idaho Power's natural gas price inputs are not factually flawed, it is still unclear if Idaho Power developed the 76 sets natural gas price inputs to: (1) model a relationship between hydro conditions and natural gas prices, (2) model a relationship between hydro conditions and electricity prices, or (3) model a relationship between all three of these variables. (Staff 200, Galbraith/12.) Implicit in the methodology used to develop the natural gas inputs is the assumption that that there is a deterministic relationship between Snake River hydro conditions and natural gas prices at the Henry Hub in Louisiana. This assumption is flawed. In fact, no such relationship exists because the impact of Northwest hydro conditions on the price of natural gas at the Henry Hub would likely be swamped by other factors such as gas production rates from mature and frontier gas producing regions, the availability of imported liquefied natural gas and natural gas storage capacity. In fact, even modeling a deterministic relationship between Northwest hydro conditions and Northwest natural gas prices is tenuous. Recent developments in the natural gas industry have tended to mitigate regional differences in natural gas prices and Northwest natural gas prices will likely continue to follow national supply and demand trends. (Staff/200, Galbraith/12.)

Because Idaho Power's modeling methodology is based on a flawed assumption that there is a deterministic relationship between hydro conditions in the Northwest and the price of natural gas at the Henry Hub in Louisiana, Staff abandoned its attempt to obtain a recommended NVPC by simply substituting realistic natural gas inputs for those used by Idaho Power. (Staff/200, Galbraith/13.) Accordingly, staff recommends that the Commission completely reject the unrealistically low market-clearing prices, and NVPC, developed from the AURORA model and substitute more representative prices.

5. The Commission should reduce Idaho Power's proposed NVPC by $63 million.

To address the flaws in Idaho Power's projected market-prices and NVPC, staff recommends that the Commission adjust Idaho Power's normalized purchased power expenses and surplus sales revenue by re-pricing Idaho Power's projected monthly energy sales and purchases, under normal hydro conditions, using flat (i.e., 24-hour) monthly electricity prices calculated from Idaho Power's forward price curves from April 30, 2004.[6] (Staff/202, Galbraith/27.) These prices are consistent with market-clearing prices in recent years, and are in fact lower than the Northwest Power and Conservation Council projections discussed above. Further, the Commission has calculated NVPC using electricity forward price curves in several previous proceedings. (Staff/200, Galbraith/16.)

The result of this adjustment, on a normalized company basis, is to increase Idaho Power's purchased power expense by $1.2 million and its surplus sales revenue by $64.1 million. The overall adjustment to NVPC is a decrease of $63.0 million ($3.1 million on

[6] Using the Company's April 30, 2004 price curve is consistent with the period the Company used to make adjustments for known rate base additions.

an Oregon allocated basis), which results in a normalized NVPC at -$15.3 million. (Staff/200, Galbraith/15.)

Idaho Power has several complaints with staff's recommendation. For the reasons discussed in the following section, none of these complaints is well founded. Notably, while Idaho Power devotes its efforts to attacking the results of Staff's recommendation, Idaho Power has devoted relatively little effort to attempt to establish that staff's criticisms of the methodology Idaho Power used to obtain its NVPC are wrong. Idaho Power bears the burden to prove by a preponderance of the evidence that its proposed NVPC would result in just and reasonable rates. *See e.g.* Order No. 01-777 at 4-6 (Docket No. UE 115). Idaho Power cannot carry this burden simply by arguing that the alternate NVPC proposed by Staff (or the intervenors) is not reasonable.

6. Idaho Power's complaints are not well founded.

A. Authorized rate of return.

First, Idaho Power argues that it will not be able to earn its authorized rate of return based on the NVPC recommended by staff because its actual NVPC will be much higher due to poor hydro conditions. Idaho Power's argument ignores fundamental ratemaking principles relied on by the Commission. The Commission has not traditionally set rates on actual costs, but on normalized costs. Even Idaho Power recognized this fact in its direct testimony, noting that that there are generally three types of ratemaking adjustments: normalizing, annualizing and adjustments for known and measurable changes. (Idaho Power/Exhibit 15T, Obenchain/Page 5-6.) Idaho Power witness Phil Obenchain describes normalizing adjustments as follows:

> [N]ormalizing adjustments are made to those items that are influenced by weather. * * * [R]etail sales revenues are normalized to reflect the impact of weather on sales. * * * (Idaho Power/Exhibit 15T, Obenchain/6.)

Notwithstanding Idaho Power's acknowledgment in its direct testimony that projected test year power costs should be normalized for the purpose of setting Idaho Power's rates, the Company now appears to assert that its power costs should be based on the actual hydro conditions expected to occur in the next several months, rather than normalized conditions. There is no support for Idaho Power's position.

To the extent that Idaho Power may be entitled to relief because of extremely poor hydro conditions, that relief is not found in a general rate case. Rather, Idaho Power may, and in fact has, request under ORS 757.259 that the Commission allow it to defer actual power costs for the purpose of including those costs in rates.

To the extent that Idaho Power may argue it is appropriate for the Commission to set rates based on actual rather than normalized power costs in this case because the rate period will be very short, the point is not well taken. Idaho Power has suggested that it intends to file a request for a general rate increase before the end of 2005, and thus, represents that rates set in this docket will be effective for a relatively short period of time. Idaho Power presumably believes that in this circumstance, the Commission should set rates based on estimates of Idaho Power's actual costs for the next several months. Again, there is no historical support for Idaho Power's position.

In fact, even Idaho Power's own testimony undermines such a proposition. In Idaho Power's rebuttal testimony, Idaho Power witness Dennis Peseau testified that his testimony regarding the appropriate level of NVPC is predicated on his assumption "that the objective of the whole power cost normalization effort by Idaho Power and other parties is to estimate the single level of net power costs that would reflect the average production costs incurred by Idaho Power over multiple water years." (Idaho Power/300, Peseau/3.) Mr. Peseau explained that,

> While we understand that exactly average water conditions will seldom prevail during a test year, hopefully over time the methods of estimating normalized power costs will tend toward the power costs actually incurred if there is no systematic bias upward or downward in the normalized power cost estimates, the ratepayers and shareholders are well served in that actual power costs are recouped over time. (Idaho Power/300, Peseau/3.)

Furthermore, as a practical matter, only Idaho Power can control whether it will file a request for a general rate increase by the end of 2005. It would be risky for the Commission to set rates assuming that they will be in effect for less than one year or so when the Commission has no assurance that this in fact will be the case.

B. Expectation of poor hydro in 2005.

Second, Idaho Power also argues that the Commission should reject the staff's recommendation to use the April 30, 2004 forward market price curve to obtain the value of Idaho Power's projected sales on the ground the April 30, 2004 forward market price curve is predicated on an expectation of poor hydro conditions for 2005. Idaho Power's assertion is unsupported.

Idaho Power witness Peseau argues that a lack of a pronounced increase in forward prices after April 30, 2004 is evidence that staff's recommended prices are drought-driven. (Idaho Power/ 300, Peseau/12-13). In fact, review of forward price curves in 2004 and 2005 show a pronounced increase in forward prices beginning in early 2005 (as opposed to Spring 2004). For example, the forward on-peak price for power delivery in May 2005 increased from $37.53 per MWh on January 1, 2005 to $55.00 per

MWh on April 1, 2005. The forward on-peak price for power delivery in June 2005 increased from $37.13 per MWh to $62.75 per MWh, and the July 2005 price increased from $49.45 per MWh to $71.03 per MWh, over the same timer period. (Staff/300, Galbraith/12.)

Staff Exhibit 302/Galbraith/13 shows the forward on-peak prices for all delivery months. For nearly all of calendar year 2004, the forward on-peak prices for delivery during May, June and July of 2005 were significantly lower than the prices for delivery during the rest of the months of 2005. In early 2005, the forward on-peak prices for May, June and July converged on the higher price level associated with the other months of 2005. Staff Exhibit/302 Galbraith/14 shows a similar pattern for the forward off-peak prices. This movement of prices in early 2005 indicates that early 2005 is when electricity market began to anticipate poor hydro conditions for the months of May, June and July 2005. (Staff/200, Galbraith/13.)

C. Single price series.

Third, Idaho Power also argues the Commission should reject staff's recommendation to use the April 30, 2004 forward electricity price curve in place of Idaho Power's market-clearing price projections on the ground that it is not appropriate to normalize Idaho Power's NVPC using a single price series. Idaho Power's complaint does not warrant the Commission's rejection of staff's recommendation. Notwithstanding the fact that staff's recommendation requires the Commission to normalize Idaho Power's NVPC using a single price series, staff's alternative is still vastly superior to using Idaho Power's unreliable and unrealistic projections of market-clearing prices. As Mr. Galbraith testified at the hearing, "[i]n this case, it's better rate-making practice to use one scenario than to use 76 flawed scenarios." (Tr at 11.)

However, in the event the Commission would prefer to use a range of prices to determine Idaho Power's expenses and revenues associated with purchases and sales of generation, as opposed to the flat price recommended by staff, staff recommends that the Commission use Staff's AURORA projections to normalize Idaho Power's test period NVPC. To develop the normalizing adjustment, staff used the May 28, 2004 settlement of the NYMEX Henry Hub futures contracts for the 2005 delivery strip to establish a mid-point, or average, price level for the AURORA natural gas price inputs. Staff's average annual natural gas price at Henry Hub for the 76 hydro conditions is $5.85 per MMBTU. In comparison, Idaho Power's annual average price is $3.88 MMBTU. (Staff/300, Galbraith/14 and Staff/407.) This alternate adjustment would reduce Idaho Power's test period NVPC by $23.2 million on a total company basis. Notably, as previously discussed in this brief, normalizing Idaho Power's AURORA projections is not staff's primary recommendation because staff does not believe that Idaho Power's deterministic-fundamentals based AURORA modeling is up to the challenge of modeling the complex relationship between Northwest hydro conditions and Northwest energy prices.

D. Off-peak vs. on-peak.

Fourth, Idaho Power also argues that "[s]taff's proposed $63 million downward adjustment to normalized power supply costs is largely an artifact of failing to price Idaho Power's normalized surplus power sales at lower off-peak values indicative of its typical daily load shapes." (Idaho Power/300, Peseau/4.) Because Idaho Power failed to provide staff with information that would show it makes sales during the off-peak, Idaho Power's argument is not well taken. Staff attempted to obtain data from Idaho Power that would allow staff to re-price Idaho Power's projected surplus sales and market purchases on a monthly on-peak and off-peak basis. However, Idaho declined to provide the on-peak and off-peak breakdown of projected energy sales on the ground it would be burdensome. (Staff/200,Galbraith/15.) In light of Idaho Power's failure to provide evidence that demonstrates that it does in fact make sales of its surplus energy during the off-peak, its argument that the Commission should price its surplus sales at the lower off-peak prices is a weak one.

To the extent that the Commission believes it is appropriate to use shaped prices to determine Idaho Power's NVPC, notwithstanding Idaho Power's failure to prove its assertion that it sells power during the off-peak and purchases during the off-peak, staff recommends that the Commission re-price the test period power purchases using the company's April 30, 2004 on-peak forward prices and re-price the test period power sales using the April 30, 2004 off-peak forward prices. This alternate adjustment would reduce Idaho Power's test period NVPC by $49.5 million on a total company basis. (Staff/300, Galbraith/15.)

e. Historical NVPC.

Finally, Idaho Power argues that the NVPC obtained by using staff's recommendation is significantly lower than the Company's actual NVPC in past years. Idaho Power's argument on this point is also not persuasive. As noted by CUB in its opening testimony, "today's power market is vastly different than it was a decade ago." (CUB/100, Jenks-Brown/4.)

> [I]t seems reasonable to us that Idaho Power's power costs have declined due to the value of the Company's excess generation and its sales for resale. The Company's load has changed little, the Company has a long position so the cost of serving that load has changed little, but the value of its excess generation has increased significantly. The Company has seen a slight decrease in the price of coal, and though the Company has had to turn to natural gas as a fuel, its use is limited to a single peaking plant [that] is primarily used to meet extreme mid-summer load conditions. * * * Given what we know about current market conditions and prices, combined with forecasts from the Council, the price at which Idaho Power sells its excess generation needs to be raised to more accurately reflect the current market value of that generation. (CUB/100, Jenks-Brown/5-6.)

In sum, staff presented evidence demonstrating that Idaho Power's natural gas price inputs for its power cost model are flawed in that they are unrealistically low, and that this flaw results in unrealistically low market-clearing prices and ultimately, a NVPC that fails to properly value revenues obtained from sale of Idaho Power's surplus generation. Idaho Power did not present evidence to defend the inputs used in its AURORA model, or the model itself. Rather than defending the integrity of the power cost model used to obtain its NVPC, Idaho Power largely attempts to persuade the Commission to adopt its recommended NVPC because this NVPC will allow Idaho Power better opportunity to recover its costs in 2005, which is expected to be a poor hydro year, than the NVPC proposed by Staff. However, the Commission has historically set costs based on normalized power costs, not actual costs. Accordingly, Idaho Power's efforts in this case are misdirected. In absence of evidence refuting staff's criticisms of Idaho Power's power cost model and its output, and in absence of compelling evidence demonstrating that the Commission should adopt Idaho Power's NVPC notwithstanding the flaws in its power cost modeling, the Commission should reject Idaho Power's NVPC and adopt the NVPC proposed by Staff.

b. Time-of-use rates for industrial customers

As a general matter, staff supports rates that reflect cost causation. Such rates send price signals to customers to reflect the value of the energy consumed by customers. With respect to Idaho Power's time-of-use rate proposal for industrial customers, staff agrees with the testimony of Idaho Power witness Pete Pengilly that time-of-use rates can give customers financial incentive to change their usage patterns. (Idaho Power/400, Pengilly/3.) As noted by Mr. Pengilly,

> [t]ime-of-use pricing better matches the customer's rate for energy to the Company's cost of energy, thereby providing a clearer price signal to customers regarding the energy costs associated with their usage pattern. This presents an opportunity for customers to reduce their bills by shifting their energy consumption to less costly time periods. (Idaho Power/400, Pengilly/5.)

Staff is not persuaded by the Industrial Customers' argument that "dummy bills" sent to customers from June 1 to December 1, following approval of time-of-use rates for Idaho Schedule 19 industrial customers show that time-of-use rates will not be effective for industrial customers. As noted by Idaho Power, the "dummy bills" did not send any actual price signals, but only provided customers taking service under Idaho Power's Schedule 19 with a comparison of what their bills would have been had they actually been charged with time-of-use rate rather than the flat seasonal rates actually in effect.

Staff also does not agree with the Industrial Customers that time-of-use pricing is overly complex.

Because time-of-use rates can give customers financial incentive to change their usage patterns to conserve electricity during peak hours, and because adopting Idaho Power's time-of-use rate proposal will provide consistency for Idaho Power's industrial customers that operate in both Oregon and Idaho, staff supports Idaho Power's time-of-use rate proposal for industrial customers.

c. Seasonal rates for residential customers

For residential customers, CUB's testimony regarding simplicity has merit. Rather than having the rates change twice a year to reflect the seasons, a single rate will be more understandable to customers. Staff believes this understandability component is of greater value than the potential benefits associated with lower use during the peak period.

d. Distributed generation

The Industrial Customers ask the Commission to direct staff to work with Idaho Power to develop a study of dispatchable standby generation programs, and "to work with customers such the Holy Rosary Medial Center along with any other emergency generators in [Idaho Power's] Oregon service territory in an effort to determine the variability of using these generators to help meet peak load. (Direct testimony of Don Reading, Ph.D. at 16.) Staff shares the Industrial Customers' interest in dispatchable standby generation and has prepared extensive reports on demand response and distributed generation. *See e.g.*, Public Utility Commission of Oregon, *Demand Response Programs for Oregon Utilities* (May 2003); Lisa Schwartz, *Distributed Generation in Oregon: Overview, Regulatory Barriers and Recommendations* (February 2005).

However, notwithstanding the fact that staff agrees with the importance of dispatchable standby generation, staff believes that priorities regarding resource selection should be established in an integrated resource planning docket, rather than a general rate case. Staff expects that Idaho Power should be continually evaluating dispatchable standby generation programs and that it will make a filing to implement such programs as it deems reasonable. Idaho Power has stated that it is interested in potential distributed generation opportunities that are beneficial to its retail customers and states that it will voluntarily pursue the distributed generation potential with Holy Rosary Medical Center and any other customer with distributed generation potential. (Idaho Power/600, Gale/3.) Accordingly, staff does not recommend that the Commission specify and formal requirements for Idaho Power regarding distributed generation. Instead, staff recommends that the Commission acknowledge the mutual interest of distributed generation by both customers and the Company and that the Commission acknowledge its [the Commission's] support for such programs.

e. Power supply quality.

The Industrial Customers discuss the frequency and duration of service outages to industrial customers in their direct and surrebuttal testimony. (Direct testimony of Don Reading, Ph.D. at 24-25; Surrebuttal testimony of Don Reading, Ph.D at 6-9.) The Industrial Customers' witness, Dr. Reading, concludes, "[i]t is important for the Commission to order Idaho Power to address this issue over the coming rate period and to work proactively with their customers to solve these power quality issues." (Direct testimony of Don Reading, Ph.D. at 25.) Staff shares the Industrial Customers' concern regarding service quality. However, Idaho Power has expressed its willingness to work with Ore-Ida on its service quality problems and has stated the Company's policy of proactively working with customers to resolve power quality issues. (Idaho Power/900, Kolar/4.) Staff believes that this policy and the Company's commitment to service quality is sufficient to address the concerns raised by the Industrial Customers and does not recommend that the Commission direct Idaho Power to take any particular action with respect to this issue.

f. Danskin.

Idaho Power's requested rate increase includes inclusion of its Danskin Power Plant ("Danskin") in rate base. Danskin consists of two identical 45 MW natural gas-fired combustion turbines. Danskin become commercially operative in September 2001. The Industrial Customers request that the Commission decline to give Danskin rate base treatment on the ground that the cost of Danskin is too high. In support of this recommendation, Idaho Power witness Dr. Reading describes the amount of plant use in hours and actual costs of operation since the plant came online. While this information may be pertinent to whether the plant is used and useful, it has nothing to do with the prudence of the decision to acquire the resource.

To determine the prudence of a utility's decision to acquire a resource, the Commission examines the objective reasonableness of a company's actions measured at the time the company acted. OPUC Order No. 02-469. Prudence is determined by the reasonableness of the actions based on information that was available, or could reasonably have been available, at the time of the actions. (OPUC Order No. 99-033 at 36-37.) In applying this standard, the Commission does not focus on the outcome of the utility's decision, as the following passage from *In re Transition Costs*, Docket No. UM 834 shows:

> [When utilities mitigate transition costs,] they must behave prudently, meaning that their decisions were reasonable, based on information that was available (or could reasonably have been available) at the time. The Commission has applied the prudence standard for many

> years in deciding whether to include in rate base the full amount of a utility's investment in a new resource (as opposed to a standard that, say, focuses on the outcome of the utility's decision.) OPUC Order No. 98-353 at 9.

As a general matter, whether a utility acted reasonably in acquiring a new resource depends on its actions vis-à-vis its resource need and what was least cost at the time the utility acquired the resource. Idaho Power's need for additional resources during the relevant time period was established by the Company's June 2000 Integrated Resource Plan (IRP), acknowledged by the Commission in Order No. 00-748. The near-term action plan in the IRP called for the acquisition of 250 MW of summer and 200MW winter resource in the next two years.

As is known, beginning in May 2000, the western electricity markets became extremely volatile. The Company was caught in a very difficult situation. The Company needed power in the near-term and market purchases were a very expensive option as forward prices for power in February 2001 were over $300 per MWh for the rest of 2001. Idaho Power initiated a request-for-proposal process in August 2000, which led to an April 2001 application by the Company to Idaho Public Utility Commission (IPUC) for a certificate of public convenience and necessity for the 90 MW combustion turbine plant. On July 11, 2001, the IPUC issued a Certificate of Public Convenience and Necessity for Danskin and allowed rate basing of Danskin in May 2004.

Given Idaho Power's identified need for power in 2001 and the extraordinary market that existed, staff recommends that the Commission find Idaho Power prudently acquired Danskin and allow the plant to be added to Idaho Power's rate base in Oregon.

IV. Conclusion

The Stipulation entered into by Idaho Power, staff, CUB and the Industrial Customers should be approved. Further, the Commission should 1) reject the NVPC proposed by Idaho Power and adopt the NVPC proposed by staff; 2) adopt the Danskin plant into rate base; 3) adopt Idaho Power's proposal for time-of-use rates for industrial customers; 4) reject Idaho Power's proposal for seasonal rates for residential customers; 5) acknowledge the importance of distributed generation (e.g., emergency generators), but decline to order Idaho Power to take any particular action in facilitating distributed generation in its Oregon service territory; 6) decline the Industrial Customers' request to issue a specific order to Idaho Power regarding power supply quality.

DATED this 13th day of June 2005.

Respectfully submitted,

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CERTIFICATE OF SERVICE

I hereby certify that on the 13th day of June 2005, I served the foregoing UE 167 Staff Opening Brief upon the parties, hereto by the method/s indicated below:

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