ENTERED 07/28/05

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 167

In the Matter of IDAHO POWER COMPANY Application for general rate increase in the company's Oregon annual revenues of $4,418,908, or 17.52 percent overall.	)))))))	ORDER

DISPOSITION: STIPULATION ADOPTED; APPLICATION FOR GENERAL RATE REVISION APPROVED AS REVISED

On September 21, 2004, Idaho Power Company (Idaho Power) filed an application for a general rate increase in the company's Oregon annual revenues of $4,418,908, or 17.52 percent overall. Idaho Power requested that the rates take effect October 20, 2004.

On October 19, 2004, the Commission found good and sufficient cause to investigate the propriety and reasonableness of the tariff sheets pursuant to ORS 757.210 and ORS 757.215. *See* Order No. 04-617. The Commission ordered the rates to be suspended for nine months from October 20, 2004. The suspension period was later extended to July 29, 2005.

On November 18, 2004, a prehearing conference and public comment hearing/open house meeting were held in Ontario, Oregon. Parties to the docket were Idaho Power, Citizens’ Utility Board of Oregon (CUB), Oregon Industrial Customers of Idaho Power (OICIP), Portland General Electric Company (PGE), and Commission Staff (Staff). PGE did not submit testimony or briefs.

On May 20, 2005, Idaho Power, Staff, CUB, and OICIP filed a joint stipulation and supporting joint testimony as to every issue except the following disputed issues: (1) net variable power costs, (2) inclusion of the Danskin power plant in rate base, (3) seasonal rates for residential customers under Schedule 1, and (4) time-of-use rates for industrial customers under Schedule 19. The Stipulation and supporting testimony were entered into the record as evidence pursuant to OAR 860-014-0085(1). The remaining issues are resolved in this order.

Applicable Law

In a rate case, the Commission has two responsibilities: first, determine how much revenue the utility is entitled to receive; and second, approve a rate spread and rate design that allocates the revenue requirement among the utility's customers. *See In the matter of NW Natural*, UG 132, Order No. 99-697 at 3 (citing *American Can v. Lobdell*, 55 Or App 451, 454-55 (1982)).

During the first phase, the revenue requirement phase, we examine (a) the utility's rate base, or value of the utility's property used and useful in the rendition of service; (b) its annual gross operating revenues; (c) its annual operating expenses and costs; and (d) an appropriate rate of return. *See Pacific NW Bell v. Sabin*, 21 Or App 200, 205 (1975).

In the second phase, the rate spread and rate design phase, we rely on these determinations made in the revenue requirement phase and allocate the revenue requirement among the utility's customer classes and design rates within classes. *See* Order No. 01-787 at 5.

The applicant utility bears the burden of proof on all issues in its rate case: "the utility shall bear the burden of showing that the rate or schedule of rates proposed to be established or increased or changed is just and reasonable." ORS 757.210. The utility must first submit evidence to prove its case, then the burden of production shifts to parties that oppose the utility's proposal. *See* Order No. 99-697 at 3. The Commission considers the evidence on the whole to determine whether the utility has proven that its proposed revenue requirement and rates are reasonable.

Stipulation

On May 20, 2005, the Stipulation, attached as Appendix A, was submitted and supported by joint testimony by Idaho Power, Staff, CUB, and OICIP. The Stipulation resolves issues related to rate of return, net to gross factor, known and measurable changes to rate base, cloud seeding costs, non-labor and administrative and general expenses, employee incentive pay, payroll salary structure, wage and salary, Hells Canyon Complex legal costs, rate base additions, prepaid pension expenses, marginal costs, certain filing requirements, and conservation.

Idaho Power's 2003 test year retail revenue at current rates in Oregon was $25,220,299. Initially, the company requested a 17.52 percent overall increase in its revenue. In the Stipulation, the parties agreed to adjustments that reduce the company's request to a 12.09 percent overall increase, or $3,048,000.

The parties agree that the ratemaking adjustments contained in the Stipulation "represent[] a reasonable resolution of the issues and that rates based on this agreement would be fair, just and reasonable." Idaho Power/Staff/CUB/Industrial Customers/100 at 9. Every active party signed the Stipulation.

Conclusions

We have reviewed the Stipulation and find the proposed adjustments contained therein to be just and reasonable. Accordingly, the Stipulation is adopted.

Power Costs

The major dispute in the case relates to net power supply costs. Idaho Power defines "net power supply expenses" as "the sum of fuel expenses and purchased power expenses, minus the revenue generated from surplus power sales to other entities." IP brief, 5 (June 13, 2005); *see also* IP/300, Peseau/6. Idaho Power proposes allowing it to recover $47.7 million on a system-wide basis. Staff proposes a downward adjustment of $63 million ($3.1 million on an Oregon allocated basis), for an overall net power supply cost of negative $15.3 million; that is, surplus sales revenues exceed fuel and purchased power expense by $15.3 million. CUB proposes a downward adjustment of $66 million, for an overall cost of negative $18.6 million. *See* IP brief, 5 (June 13, 2005); Staff brief, 10-11 (June 13, 2005); CUB brief, 3 (June 13, 2005). Staff also identifies two alternatives, which would result in lesser downward adjustments.

Fundamentally, the parties dispute the price Idaho Power will be able to obtain for the sale of its excess power supply: The company projects that it will not be able to obtain prices as high as predicted by the other parties, and they will be offset by expensive power purchased during low hydro years; Staff and intervenors argue that the company underestimates the value of its excess power supply under normalized conditions. The differences in the proposals arise from disagreement about whether Idaho Power's AURORA model accurately represents normalized power supply expenses and whether the Commission should consider that the rates set in this rate case should be set as short-term rates.

To resolve this dispute, our discussion reviews first whether the Commission should consider the anticipated duration of proposed rates in a rate case; second, Idaho Power's proposed AURORA model; third, Staff's proposed alternative, using Idaho Power's April 30, 2004, forward electricity price curve for 2005, as well as Staff's other alternatives; fourth, CUB's alternative; and finally, the Commission's conclusions.

Forecasted Short-term Actual Power Costs

A threshold question is whether the Commission should consider the company's expected duration of the rates set in this docket. Idaho Power states these rates will only be in effect during 2005 and 2006, because it will file another rate case soon. *See* IP brief, 12-13 (June 13, 2005). The company is currently experiencing drought conditions and predicts that those conditions will persist through 2006. Because of those drought conditions, Idaho Power estimates that its power supply expenses will be quite high over the next two years – an estimated $169 million this year – and argues that the findings in this rate case should consider the impact of actual power costs in establishing normalized costs. *See id.*

Staff states that power costs in a rate case are generally set on a normalized basis, reflecting, for weather-dependent variables, costs expected over time, not actual costs expected in the near term. *See* Staff brief, 12-13 (June 13, 2005). CUB agrees: "By normalizing costs, the Commission can set rates on an on-going basis and the Company can do better or worse than that baseline depending on the circumstances. * * * Whether a utility files a rate case every year or every ten should not impact the definition and application of a normalized future test year." CUB brief, 4 (June 13, 2005). Staff suggests that a deferred account provides a more appropriate venue for actual power costs that fall outside the range of normalized power costs predicted in the rate case. *See* Staff brief, 12 (June 13, 2005). CUB points to Idaho Power's current deferred account docket, UM 1198, as further evidence that Idaho Power's proposed net power supply expense should not be adopted. *See* CUB brief, 4-5 (June 13, 2005).

AURORA Model

To develop its normalized power cost estimates, Idaho Power used the AURORA model, in which it examined 76 hydro scenarios, based on water years from 1928 through 2003, which could occur given 2003 test year loads. *See* IP brief, 6 (June 13, 2005). The AURORA model produces outputs related to regional hourly market-clearing electricity prices, and company level outputs for fuel expense, purchased power expense, and surplus sales revenue which reflect the regional market-clearing prices. *See* Staff brief, 3-4 (June 13, 2005).

The company states that the AURORA model produced modeled power supply expenses that closely mirrored actual costs in recent years. *See* IP brief, 7 (June 13, 2005). Based on this, Idaho Power asserts, "Near term historical data provides strong evidence that rates modeled by the Company can reasonably be expected to occur in the future," *see id.*, and that the Commission should use the AURORA price forecasts to determine the net variable power costs allowed in the rate case.

Intervenors object to the use of the AURORA model. CUB opposes Idaho Power's estimated net power supply costs as "outside the realm of reasonableness," and proposes an alternative, set forth below. CUB brief, 2 (June 13, 2005). OICIP challenges the model as an unreliable black box that should be made available for scrutiny by intervenors. *See* Reading Direct/23. OICIP suggested that Idaho Power open its model to inspection by intervenors.[1] *See* Reading Surrebuttal/4. Because model runs for past years did not accurately reflect actual prices that have already occurred, and the company stated that it has made changes to the model that cannot be verified, OICIP recommends that the Commission not use power supply costs forecasted by the AURORA model, and

[1] Idaho Power agreed to hold workshops after the end of this rate case to evaluate the effectiveness of the AURORA model. *See* IP/300, Peseau/20.

instead use prices from a different model. *See* Reading Direct/21-24; Reading Surrebuttal/2-3.

Staff also objects to use of the AURORA model to determine net variable power costs, on two grounds: (1) the gas price inputs are unrealistically low, and (2) the model assumes a deterministic relationship between Henry Hub natural gas prices and Northwest hydro conditions and is therefore inherently flawed. *See* Staff brief, 4 (June 27, 2005). Staff compares Idaho Power's estimated gas prices, ranging from $2.36 to $3.07 per MMBTu in the best hydro years, and from $4.61 to $5.30 in the worst hydro years, to actual indexed gas prices which ranged from $4.70 to $6.25 in 2003 and 2004. *See* Staff brief, 8 (June 13, 2005). Staff argues that this shows the company's gas inputs are artificially low. In addition, Staff asserts that industry developments have "mitigate[d] regional differences in natural gas prices and Northwest natural gas prices will likely continue to follow national supply and demand trends." *See id.* at 9. Because the AURORA model is based on an assumed, yet flawed, relationship between Northwest hydro conditions and natural gas prices, Staff argues that the model should be abandoned, and Staff's approach should be used. *See id.* at 10.

Idaho Power rebuts Staff's argument by stating that its natural gas inputs were based on the variability of gas prices found in Northwest Power and Conservation Council (NWPCC) documents.[2] *See* IP brief, 6 (June 27, 2005). The different prices were used to correspond with the 76 streamflow conditions, and resulted in a range of transaction prices that were used to compute net power supply costs using the AURORA model. *See id.* The company asserts that there is a relationship between hydro conditions and gas inputs, but it is not "deterministic," as Staff characterizes Idaho Power's position. *See id.*

Forward Market Price Curve from April 30, 2004

Instead of using the AURORA model, Staff proposes normalization of Idaho Power's power supply expenses using the company's April 30, 2004 forward price curve to adjust Idaho Power's filed net variable power costs. *See* Staff/200, Galbraith/14; Staff brief, 14-15 (June 13, 2005). Staff notes that the Commission has used this kind of curve in the past to calculate normalized net variable power costs. *See* Staff brief, 6 (June 27, 2005). Staff acknowledges that using just one price series is not the most desirable option, but it is preferable to Idaho Power's flawed model. *See* Staff brief, 14-15 (June 13, 2005).

Idaho Power argues that prior to 1982, the Oregon and Idaho Commissions used a single supply-side scenario assuming a median water condition and a corresponding median water market curve to determine power supply expenses, but that both commissions have since abandoned that approach as inaccurate. *See* IP brief, 6-7

[2] The company refers to the "Northwest Planning Council;" however, we assume they refer to the NWPCC, formerly named the Northwest Power Planning Council.

(June 13, 2005).[3] The company asserts that using the forward price curve from April 30, 2004, is twice skewed due to drought: first, the April 30, 2004 curve for 2005 took place in a drought year, so it already considered the resulting higher prices; and second, as the 2005 drought became evident in the early months of this year, the price curve rose even higher. *See id.* at 11.

Staff rebuts this argument by introducing evidence indicating that the forward price curve reflected even higher prices after the 2005 drought conditions worsened in early 2005. *See* Staff brief, 13-14 (June 13, 2005). Staff argues that this shows that the April 30, 2004, price curve reflects market prices without consideration of drought conditions. This approach would result in a downward adjustment of $63 million ($3.1 million on an Oregon allocated basis), for an overall net power supply cost of negative $15.3 million.

Alternative Staff Proposals

As another alternative, Staff suggests using its AURORA projections, created with different natural gas inputs derived from the May 28, 2004 settlement of the NYMEX Henry Hub futures contracts for the 2005 delivery strip. *See* Staff brief, 15 (June 13, 2005). This alternative would reduce Idaho Power's recovery for net power supply expenses by $23.2 million on a total company basis. Staff prefers use of the April 30, 2005, price curve as discussed above, because Staff believes that, even with corrected gas inputs, Idaho Power's AURORA model still produces unreasonably low market electricity prices.

Additionally, Staff argues that the Commission could calculate test period power purchases using the company's April 30, 2004, on-peak forward prices and test period power sales using the April 30, 2004, off-peak forward prices. This alternative would adjust Idaho Power's recovery for net power supply expenses by $49.5 million on a total company basis. However, Staff does not recommend this alternative, because the company did not support its claims that it sold power at off-peak prices and purchased power at on-peak prices, in spite of Staff's efforts to obtain that data from the company. *See id.* at 15-16; Staff/200, Galbraith/15.

Idaho Power argues that the fact that Staff made alternative arguments shows that Staff's proposal to use the forward price curve from April 30, 2004, is flawed and should be disregarded and the company's proposal should be adopted. *See* IP brief, 13 (June 13, 2005).

[3] However, Staff notes that, in fact, the forward price curve methodology has been more recently used by this Commission. *See In the Matter of Portland General Electric Company*, UE 115, Order No. 01-777 at 18; and subsequent PGE Resource Valuation Mechanism dockets, UE 139, Order No. 02-772; UE 149, Order No. 03-535; and UE 161, Order No. 04-573.

NWPCC Projected Prices

Another alternative, proposed by CUB, is to use the NWPCC's regional projected average wholesale prices. *See* CUB brief, 2 (June 13, 2005). In its testimony, CUB set out prices projected by the NWPCC for Southern Idaho, and conservatively applied on-peak prices to the company's purchases and off-peak prices to the company's sales of excess power. *See* CUB/100, Jenks-Brown/3-4. CUB argues that these projections will more closely mirror actual prices in the Northwest, and notes that, as proof of their accuracy, the adjustment under CUB's proposal is $66 million, very close to Staff's proposed adjustment of $63.1 million. *See id.* at 2; CUB brief, 3 (June 13, 2005).

Idaho Power does not specifically address CUB's proposal, but opposes it for the same reasons it opposes Staff's model: CUB's proposal results in estimated sale prices for the company's excess power that are much higher than prices the company predicts. *See* IP brief, 8 & n 21 (June 13, 2005). Idaho Power argues that these unrealistically high estimates will unfairly skew the net power supply expenses that can be recovered by the company in rates. *See id.*

Conclusions

To begin our discussion, it is worth noting that we set rates on a normalized basis, without consideration of specific and immediate hydro conditions.[4] This allows rates to reflect forecasted costs on an on-going basis, rather than actual costs for the short-term future. The company implicitly seeks a modification to this process by arguing that the approved rates should provide some recovery for expected actual power costs. *See* IP brief, 12-13 (June 13, 2005) (arguing that alternatives to its proposed power supply costs are unreasonable in light of predicted $169 million in actual power costs in 2005). We agree with Staff, however, that there are other regulatory mechanisms to address actual costs that fall outside the normalized costs predicted in a rate case. In fact, we are issuing an order today approving the stipulation in UM 1198, Idaho Power's application to defer, for future rate recovery, excess net power costs incurred between March 2, 2005, and February 28, 2006. Accordingly, we decline Idaho Power's request to consider the impact of specific and immediate hydro conditions and related actual costs. Moreover, we recognize that Idaho Power's system is uniquely reliant on hydro and, under Oregon's regulatory scheme, faces extended amortization of its deferred costs. Therefore, we direct the parties to work together to consider whether there is a more effective regulatory mechanism for Idaho Power to recover its allowable power costs.

[4] The Commission has not defined normalized ratemaking in the past, but the definitions provided by other commissions and the parties are generally consistent. "Normalized ratemaking * * * means that, over time, variations caused by weather or stream flow will balance out." *In the Matter of Washington Water Power Company*, Case No. WWP-E-88-3, Order No. 22816, 1989 Ida. PUC Lexis 210, at *3. Idaho Power defines normalization as "a process that considers the potential *variation* in future net power supply expenses," and does not predict the actual expenses. *See* IP/200, Said/5 (emphasis in original). At oral argument, Staff defined a normalized price as that which is expected to prevail under normal hydro conditions.

Second, we address Idaho Power's use of the AURORA model. We are persuaded by Staff's argument that, even with revised gas inputs, the model fails to accurately forecast market electricity prices under normalized conditions. Further examination of the model, other than running varied inputs, was not possible due to time constraints, according to the company. If the company chooses to again rely on the AURORA model in a future rate case, we direct the company to hold workshops to allow intervenors and Staff to examine the model more thoroughly.

In this case, we find that use of the April 30, 2004, price curve for future years provides a realistic forecast of market electricity prices under normalized conditions. The forecast is bolstered by its consistency with the NWPCC estimates promoted by CUB as an indicator of normalized prices to be used by the company. As argued by Staff, on April 30, 2004, drought conditions had not yet been realized and reflected in forward prices for 2005, as evidenced by the spike in forecasted prices after the dry winter in 2005. *See* Staff brief, 13-14 (June 13, 2005).

Third, we also find merit in Idaho Power's argument that its power purchases and sales should not be subject to flat prices. As Idaho Power indicated, when its loads are lower at off-peak times, it has excess power supply that it can sell; however, when its loads are higher, at on-peak times, it is short and must buy electricity on the market.[5] *See* IP/308, Peseau/1. Accordingly, we conclude that Idaho Power's net variable power costs should be priced using the April 30, 2004 price curve, on-peak prices for purchases and off-peak prices for sales.

By using the April 30, 2004, forward price curve to set prices for power costs, and considering purchases made at on-peak prices and sales made at off-peak prices, this results in a downward adjustment to Idaho Power's power costs of $49.5 million on a system wide basis.

Rate design

Idaho Power proposes several changes to its rate design. *See generally* IP/Ex 29T, Pengilly. Specifically, Idaho Power proposes seasonal pricing for customers receiving service under Schedules 1 (residential), 7 (small general service), 9 (large general service), and 19 (large power service). *See id.* at 4. In addition, Idaho Power proposes time-of-use pricing for Schedule 19 customers. *See id.* CUB challenges seasonal pricing for residential customers under Schedule 1. *See* CUB brief, 5 (June 13, 2005). OICIP opposes time-of-use pricing for Schedule 19 customers. *See* OICIP brief, 6 (June 27, 2005). We will discuss Idaho Power's proposal, and then we will address the contested issues in turn.[6]

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[5] We note that Staff asked for more detail on on-peak purchases and off-peak sales which the company was unable to provide. For the next rate case, we direct the company to comply with Staff's request for hourly results of system operation. *See* IP/300, Peseau/18-19.

[6] In the tariff to be filed by the company to reflect the conclusions in this order, the specific rates proposed by the company will change to reflect the stipulation as well as the adjustments made to the net power costs recovered in rates, as discussed above.

Idaho Power's Proposed Rate Design

The company plans to implement seasonal pricing by charging higher rates for power consumed during June, July, and August – the summer months. *See* IP/Ex 29T, Pengilly/5. The company states that it is experiencing higher demand in the summer because "most new residences and commercial buildings [are] being equipped with air conditioning." *See* IP/Ex 12T, Said/10. A higher demand for power during these months is driving the company to seek new resources, and Idaho Power anticipates that higher prices during this period "will encourage reduced consumption during the peak months." *See id.*

For Schedule 1 residential customers, Idaho Power intends to increase the monthly service charge from $4.00 to $5.25, consistent with the approved increase in Idaho, and charge a flat First Block[7] rate of 4.1347¢ per kilowatt hour (kWh), a ten percent increase in current First Block rates. For the Second Block of power, the company proposes a seasonal rate of 6.0521¢ per kWh in June, July, and August, and 5.4037¢ per kWh during non-summer months. *See* IP/Ex 29T, Pengilly/12.

Similar reasoning applies to the following seasonal rates proposed for Schedule 7:

Schedule	Current service charge	Proposed service charge	First Block non-summer	First Block summer	Second Block non-summer	Second Block summer
Sched 7 single-phase	$5.00	$6.55	5.3250¢	5.3250¢	5.3250¢	5.9660¢
Sched 7 three-phase	$10.00	$13.10	5.3250¢	5.3250¢	5.3250¢	5.9660¢

[7] The First Block is the first 300 kWh of usage. *See* IP/400, Pengilly/2. This is consistent with the decision by the Idaho Commission. *See In re Application of Idaho Power Company for Authority to Increase it's Interim and Base Rates and Charges for Electric Service*, Order No. 29505, 2004 Ida. PUC LEXIS 96, at *121 (May 25, 2004).

Customers under Schedules 9 and 19 do not have a block system, but instead have two layers of charges – Energy Charges and Demand Charges – which are calculated differently depending on whether usage is in a summer month or not, and whether usage is on-peak or not:

Schedule	Service charge	Basic charge	Demand non-sumr	Demand summer	Energy non-summer	Energy summer
Sched 9 Primary Service	$125.00[8]	85¢/kW basic load	$5.38/kW	$6.00/kW	2.1776¢ per kWh	2.4294¢ per kWh
Sched 9 Secondary Service 1-phase	$8.50	40¢/kW	$5.52/kW	$6.16/kW	3.0579¢ per kWh	3.4248¢ per kWh
Sched 9 Secondary Service 3-phase	$15.00	40¢/kW	As in 1-phase	As in 1-phase	As in 1-phase	As in 1-phase
Sched 9 Transm'n Service	$125.00	42¢/kW	$5.20/kW	$5.80/kW	2.1291¢ per kWh	2.3753¢ per kWh
Sched 19 Primary Service	$125.00	85¢/kW	$5.38/kW	$5.64/kW	Mid: 2.1680¢ Off: 2.0684¢	On: 2.6550¢ Mid: 2.3965¢ Off: 2.2335¢
Sched 19 Secondary Service	$125.00	40¢/kW	$5.52/kW	$5.80/kW	Mid: 3.5073¢ Off: 3.1305¢	On: 3.8736¢ Mid: 3.6804¢ Off: 3.4302¢
Sched 19 Transm'n Service	$125.00	42¢/kW	$5.20/kW	$5.44/kW	Mid: 2.1051¢ Off: 2.0084¢	On: 2.5835¢ Mid: 2.3317¢ Off: 2.1733¢

As indicated above, there are two kinds of usage charges: the Energy Charge and the Demand Charge. Most Energy Charges are simple in application, except the seasonal time-of-use Energy Charges for customers under Schedule 19. During the summer months, the On-Peak block is defined as 1pm to 9pm, Monday through Friday; the Mid-Peak block is 7am through 1pm and 9pm and 11pm, Monday through Friday, and 7am through 11pm, Saturday, Sunday, and holidays; the Off-Peak block is 11pm through 7am, every day. During the non-summer months, there will only be a Mid-Peak block from 7am through 11pm, Monday through Saturday; and an Off-Peak block from 11pm through 7am, Monday through Saturday, and all hours on Sunday and holidays. All hours are in Mountain Time. *See* IP/ Ex 29T, Pengilly/21-22. During those hours, the rates would be charged per kWh, as set out above.

[8] Customers with the $125.00 service charge have automated metering.

In addition, the company proposes a two-tiered Demand Charge during the summer months. The formula involves determining when a customer has its highest 15 minutes of use, and charging an increased additional Demand Charge if that 15 minute period is during On-Peak hours. The additional Demand Charge is less if the 15 minute period is during other hours. Idaho Power hopes that the weighted Demand charge will provide incentives to customers to have their period of highest demand during a time other than On-Peak hours.

The company proposed energy charges similar to those approved by the Idaho Commission and balanced the revenue requirement primarily on the Demand Charge and secondarily on the Basic Charge. *See* IP/Ex 29T, Pengilly/20-21. Idaho Power supports the seasonal rate design and time-of-use rates as appropriate signals to customers as to when electricity is most expensive, in order to encourage usage during other times. *See* IP/400, Pengilly/2.

Schedule 1: Seasonal Pricing

CUB challenges the company's proposed seasonal rate design for Schedule 1 residential customers. *See* CUB/100, Jenks-Brown/5-6. CUB asserts that residential customers' use peaks in the winter, not the summer, and those higher winter bills provide an incentive for conservation. *See id.* at 5-6. As a consequence, CUB is concerned that a higher rate for usage in the summer will seem to level out the customers' bill and will not provide an incentive to conserve energy. *See id.* at 6. Particularly in light of Idaho Power's argument that it needs to encourage conservation during summer months, CUB asserts that the proposed seasonal rates will not provide an incentive to residential customers to conserve energy in the summer. *See* CUB/200, Jenks-Brown/3.

Idaho Power argues that generally higher prices will encourage conservation in the winter, and that the greater rate increase for electricity over 300 kWh will also discourage excessive energy use in summer. *See* IP/400, Pengilly/2. The company asserts that it "has seen no evidence to suggest that customers focus exclusively on the size of their bill and ignore changes in rates, or that higher summer rates will lessen the impact of winter bills. Rather, the Company's experience is that customers respond to both bills *and* rates." IP brief, 17 (June 13, 2005) (emphasis in original). Idaho Power further argues that conservation is not the only reason to implement seasonal rates; rate design should also link rates and expenses, reducing subsidies of one customer group by another. *See id.* at 18.

Staff agrees with CUB that a variable seasonal rate could be confusing to customers, and that a single rate will be more understandable. Generally, Staff supports rates that reflect the cost of service. *See* Staff brief, 18 (June 13, 2005). However, Staff asserts that a simpler, single rate "is of greater value than the potential benefits associated with lower use during the peak period." *See id.* at 19.

Conclusions regarding Schedule 1 Seasonal Pricing

Idaho Power is correct that CUB produces no evidence to prove customers will be less likely to respond to higher summer bills through block prices designed to provide conservation incentives. However, Idaho Power also presents no evidence to support its assertion to the contrary.[9] In addition to mixed price signals and their effect on encouraging conservation, we are particularly concerned about the effect of new weighted summer rates on customers. At oral argument, the company was asked about the impact this rate design may have on different groups of residential customers. The company had no response or supporting data. Without more evidence in the record regarding the impact of higher summer rates on Oregon customers, we conclude that the proposed block rate design for residential customers is not just and reasonable and should not be approved.

Schedule 19: Time-of-Use Pricing

OICIP argues against seasonal time-of-use rates for Schedule 19 industrial customers, which would result in the highest rates during the summer months between 1:00 p.m. and 9:00 p.m. OICIP witness Dr. Reading asserts that the rate design is intended to promote conservation, which is difficult for industrial customers who do not have flexibility in their energy usage. *See* Reading Surrebuttal/9-10. Reading notes that these rates were approved in Idaho, with a six-month phase-in period during which time customers were charged at traditional rates and provided "dummy" bills reflecting the new time-of-use rates. *See* Reading Direct/17. After that six-month period, Idaho Power found that the dummy bills altered neither revenue nor usage, because the affected customers "tend to be high load factor, consistent use customers." *See id.* at 18 (quoting Idaho Power's response to Data Request No. 2). Dr. Reading argues that Oregon customers will be similarly unresponsive to a complicated billing method, and suggests that the time-of-use rates may be better suited to residential or even commercial classes than to industrial customers. *See id.* at 19.

Idaho Power disputes OICIP's characterization and portrays its proposal as providing standard rates for peak usage, but allowing discounts for off-peak usage and encouraging flexible usage over time.[10] *See* IP/400, Pengilly/3, 5. The company states that time-of-use rates have not been in effect in Idaho long enough to indicate whether

[9] In fact, Idaho Power's brief points to a bald assertion made in testimony, that customers will respond both to bills and rates, which is similarly not reinforced with actual evidence. *See* IP/800, Pengilly/2:11-12 (cited by IP brief, 17 n 68 (June 13, 2005)). These statements are of limited use and should be better supported with evidence in future filings.

[10] Although Idaho Power attempts to draw a distinction, it is unclear what the difference is between OICIP's argument that the proposed pricing is designed to reduce consumption during on-peak hours, and Idaho Power's argument that the pricing will shift peak consumption to off-peak hours. *See* IP brief, 18-19 (June 13, 2005). However, their arguments are clear. OICIP opposes the incentives for the shift because it argues that industrial customers do not have the flexibility to shift their usage to off-peak hours. *See* OICIP brief, 6 (June 27, 2005). Idaho Power supports time of use rates to encourage industrial customers to shift their usage over the long run. *See* IP brief, 19 (June 13, 2005).

the rates are useful in influencing customer usage patterns, but may do so over a longer period of time. *See* IP brief, 18 (June 13, 2005). Idaho Power states that the proposed rates are "intended to more closely match the prices customers pay with the expenses incurred by the Company to provide the service." *See id.* at 19.

Staff supports the company's proposed time-of-use rates for several reasons. As indicated, Staff favors rates that reflect the cost of service. *See* Staff brief, 18 (June 13, 2005). In this instance, Staff agrees with Idaho Power's arguments that, over time, time-of-use rates will encourage industrial customers to make choices that will shift power usage to non-peak hours. *See id.* "Dummy bills" do not send those price signals, and so would not be as useful, Staff argues. *See id.* Because the Idaho Commission has already approved time-of-use rates for industrial customers, Staff supports a similar change in Oregon for consistency, particularly for customers who operate in both Oregon and Idaho. *See id.* at 18-19. Staff disagreed that the proposed time-of-use rates were confusing for industrial customers. *See id.* at 18.

Conclusions Regarding Schedule 19 Time-of-Use Pricing

The Schedule 19 time-of-use pricing formula is quite complex, but use of the formula in Oregon would provide consistency for businesses who have facilities in both Idaho and Oregon. As industrial customers upgrade their equipment and systems over time, and respond to price signals that mirror demand, they may make different choices that would lessen the stress on Idaho Power's system during on-peak hours. For these reasons, we conclude that time-of-use pricing should be implemented for Schedule 19 industrial customers.

Danskin Station Generating Facility

The Danskin Power Plant was built during the summer of 2001 and began producing power in September 2001. *See generally* IP/Ex 12T, Said/7-8; Reading Direct/2-4. Located near Mountain Home, Idaho, it consists of two 45 MW natural gas-fired combustion turbines supplied by the Williams Northwest Pipeline located near the plant. It is a peaking plant, intended to be used less often and solely to meet extreme load conditions, and it is limited in its hours of operation due to air quality standards. *See id.*

Idaho Power argues that the Danskin plant is necessary because load has grown beyond its capacity to meet demand through hydroelectric facilities. *See* IP/Ex 12T, Said/10. The Danskin plant is used to serve peak loads, support system reliability, and provide electricity "when there is no transmission available or when market prices are so high that market purchases are unattractive." *Id.* at Said/12, 14. The company notes that the Idaho and Oregon Commissions acknowledged Idaho Power's 2000 and 2002 Integrated Resource Plans (IRPs), which identified the need for a facility such as Danskin as a cost-effective means of meeting summer peaks. *See* IP brief, 14 (June 13, 2005).

OICIP witness Dr. Don Reading challenges Idaho Power's inclusion of the construction and maintenance costs of the Danskin facility in rates, arguing that even as a peaking facility, it is a poor value for customers: "At a cost this high and output this low, the facility should be excluded from rate base because it is reasonable to assume alternative sources could be found at a more reasonable cost to Oregon ratepayers." *See* Reading Surrebuttal/5. Reading also asserts that Idaho Power has operated the plant even less than when it proposed the plant's construction before the Idaho Commission: instead of more than 5,000 hours every year, the company operated the plant 358 hours in 2001, 753 hours in 2002, and 837 hours in 2003. *See* Reading Direct/6. In addition, a new planned facility, the Bennett Mountain plant, will result in even less use of the Danskin facility in coming years, resulting in even higher normalized costs for customers. *See id.* at 12-13. OICIP also argues that the specifications of the 90 MW Danskin facility do not meet those set forth in the IRP plans for a 250 MW plant. *See* OICIP brief, 4-5 (June 13, 2005). OICIP argues that Idaho Power is misleading the Commission as to when it decided to build Danskin, and that it was built not for the benefit of consumers, but to recover high profits in volatile markets, such as those seen in 2001. *See id.* at 5.

In countering Dr. Reading's arguments, Idaho Power notes that the Idaho Commission rejected those arguments in Idaho Power's last rate case. *See* IP/200, Said/19-26. Idaho Power witness Mr. Said argues that Danskin was always intended to be a peaking plant and, as such, its costs tend to be higher. The company argues that a peaking plant such as Danskin improves the reliability of the system. In addition, Said states that the decision to build Danskin was made during a time of volatile electricity markets in 2001, and in light of the circumstances present at that time, Danskin was considered a reasonable resource to provide stability at a prudent cost. *See id.* at Said/21-22. Idaho Power argues that it would have been imprudent to cease construction midway through the project, after the power supply shortage had abated. *See id.* at Said/22-24. Further, even after Bennett Mountain is completed, Idaho Power states that it will still need to activate the Danskin facility during its growing summer peak load period. In addition, Idaho Power asserts that Danskin serves as a hedge against runaway wholesale prices, system emergencies, and extreme load hours during peak load days. *See id.* at Said/25.

Staff analyzes inclusion of the Danskin plant in rate base in light of whether the decision was prudent or reasonable based on information that was available, or could reasonably have been available, at the time the decision was made. *See* Staff brief, 21 (June 13, 2005) (citing Order No. 99-033 at 36-37). Staff notes that the Commission acknowledged the company's 2000 IRP, which called for the acquisition of 250 MW of summer and 200 MW of winter resources in the following two years. *See id.* at 22. Given the volatile markets and increased demand that existed at the time Idaho Power built the Danskin plant, Staff recommends that the Commission find that Idaho Power prudently acquired Danskin and allow the plant to be added to Idaho Power's rate base in Oregon. *See id.*

Conclusions

As noted by the parties, we must review the company's decision to build Danskin for whether it was prudent or reasonable based on information that was available at the time the decision was made. Idaho Power's decision to build Danskin, made during a time of volatile electricity prices in 2001, was a prudent decision for the company to insulate itself from variable hydro supply and extreme market electricity prices. We have acknowledged in the past that Idaho Power requires increased resources. *See* Order No. 00-748. Therefore, we conclude that the Danskin facility should be included in rate base.

Distributed Generation

OICIP witness Dr. Reading also suggests that the Commission "direct its Staff and the Company to cooperate with Holy Rosary Medical Center along with any other emergency generators in the Oregon service territory in an effort to determine the [viability] of using [private] generators to help meet peak load." *See* Reading Direct/16. By using private generation to meet peak demands for power, OICIP implies that facilities such as Danskin and Bennett Mountain are not necessary to meet peak customer loads and should not be included in rate base. *See id.*

Idaho Power voluntarily committed to exploring distributed generation opportunities with Holy Rosary Medical Center and any other Oregon customer with such potential, without direction by the Commission. *See* IP/600, Gale/3.

Staff agrees with OICIP that dispatchable standby generation could be an important asset to meet peak load demands. *See* Staff brief, 19 (June 13, 2005). However, Staff believes that such decisions should be established in an integrated resource planning docket, not a rate case. *See id.* Due to the company's commitments to voluntarily pursue those opportunities, such as the Holy Rosary Medical Center standby generation, Staff recommends that the Commission not undertake any specific action at this time. *See id.* at 20.

Conclusions

We appreciate Idaho Power's commitment to work with customers and look forward to future IRPs which incorporate distributed generation to serve customers and maintain reasonable rates. We also agree with Staff that a rate case is not the best forum to address this issue and will address it in a future IRP docket.

Power Supply Quality

OICIP and Idaho Power also dispute the level of power supply quality provided to customers, particularly industrial customers, in the Oregon service territory. OICIP cites outages in the Heinz and Ore-Ida plants, noting that for every outage, an entire production line is disrupted and substantial amounts of perishable product must be discarded. *See* Reading Direct/25; Reading Surrebuttal/8.

The company's records and the customers' records do not agree on when the outages occurred and how long they lasted. *See* Reading Surrebuttal/8; IP brief, 20 (June 13, 2005). Idaho Power asserts that it complies with Oregon requirements for power supply quality, and that other factors may be at work to cause disruptions. *See* IP brief, 20 (June 13, 2005). The company commits to working with individual customers to resolve power supply complaints.

Staff also expresses concern about power supply quality issues. *See* Staff brief, 20 (June 13, 2005). However, in light of the company's commitment to work with customers, Staff recommends that the Commission take no specific action on the matter. *See id.* at 20-21; *see also* Staff brief, 12 (June 27, 2005).

Conclusions

We are also concerned about power outages, especially as they affect industries in this service territory which process perishable product and suffer disproportionately from even brief interruptions in power. However, there appear to be factual discrepancies between the company and the industrial customers as to what constitutes an outage. We strongly encourage the company and customers to work together meet the customers' particular power supply needs. If further problems occur, a complaint may be filed with the Commission to determine the facts and resolve the issue.

Final Conclusions

Based on the record in this case, Idaho Power's rates that result from the Stipulation and the Commission's conclusions in the body of this order are just and reasonable. A spreadsheet reflecting the results of operations is attached as Appendix B.

ORDER

IT IS ORDERED that:

1. Advice No. 04-06, filed by Idaho Power Company on September 21, 2004, is permanently suspended.

2. The stipulation attached as Appendix A is adopted in its entirety.

3. Idaho Power Company may file revised tariffs consistent with the findings of fact and conclusions of law in this order, no earlier than the first business day after the issuance of this order. The tariffs shall go into effect no earlier than three business days after they are filed.

Made, entered, and effective JUL 28 2005.

Lee Beyer
Chairman

John Savage
Commissioner

Ray Baum
Commissioner

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-014-0095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-013-0070(2). A party may appeal this order to a court pursuant to applicable law.

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 ELECTRIC SERVICE TO CUSTOMERS IN THE STATE OF OREGON	STIPULATION

INTRODUCTION

1. The parties to this Stipulation are Idaho Power Company ("Idaho Power"), staff of the Public Utility Commission of Oregon ("Staff"), the Citizens' Utility Board ("CUB"), and the Oregon Industrial Customers of Idaho Power ("Industrial Customers"), collectively referred to as "the Parties."[1]

2. By entering into this Stipulation, the Parties intend to resolve, with the exceptions described below, a substantial number of the issues arising from and relating to Idaho Power's Application for General Rate Increase in the Company's Oregon Annual Revenues of $4,418,908, or 17.52 percent overall ("Application"). One material issue not addressed in this Stipulation is the amount of power costs that should be included in Idaho Power's revenue requirement.

BACKGROUND

3. On September 21, 2004, Idaho Power filed its Application requesting a general rate increase and revised tariff schedules. Idaho Power filed the testimony of ten witnesses and supporting exhibits in support of the Application and revised tariff schedules.

4. CUB filed its notice of intervention on October 11, 2004.

[1] Idaho Power, CUB, Staff and the Industrial Customers are the only active parties to this docket. PGE also intervened in the matter, but did not attend settlement negotiations or file testimony.

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5. On October 20, 2004, the Public Utility Commission ("Commission") suspended the tariff schedules for nine months to allow opportunity to investigate Idaho Power's filing.

6. On November 18, 2004, Administrative Law Judge Christina Smith presided over a pre-hearing conference and public comment hearing/open house meeting in Ontario, Oregon.

7. On December 21, 2004, the ALJ allowed the petition to intervene filed by the Industrial Customers.

8. On or about February 2, 2005, CUB, the Industrial Customers and Staff circulated settlement proposals to all Parties. The parties met for settlement negotiations on February 14 and 24, 2005. As a result of those settlement negotiations, the Parties enter into this Stipulation.

STIPULATION

Revenue requirement issues

9. The Parties agree for settlement purposes that the following adjustments shall be made to the revenue requirement proposed in Idaho Power's Application:

a. Rate of return

i. For all Oregon regulation purposes, Idaho Power's weighted cost of capital will be set at 7.83%

ii. For all Oregon regulatory purposes, cost of equity will be set at 10.0%, which includes 10 basis points for flotation costs.

iii. For all Oregon regulatory purposes, the embedded cost of long term debt will be assumed to be 5.99%

iv. For all Oregon regulatory purposes, the capital structure will be assumed to be composed of 54.03% debt and 45.97% equity

v. These adjustments will result in a downward adjustment to revenue requirement in the amount of $670,000.

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b. Net to gross factor

The net to gross factor will be set to include uncollectibles. This adjustment will result in an upward adjustment to revenue requirement of $14,000.

c. Known and measurable changes to rate base

Revenues and expenses for changes to rate base will be imputed consistent with the method used by the OPUC in previous rate cases. This adjustment will result in a revenue requirement deduction of $23,000.

d. Cloud seeding costs.

Idaho Power's capitalized costs and test-year expenses for cloud seeding will be excluded. This adjustment will result in a revenue requirement deduction of $52,000.

e. Non-labor and A&G expenses

Shareholder costs and costs attributable to FAS adjustments and insurance will be excluded and removed from A&G expense. This will result in a revenue requirement deduction of $187,000.

f. Employee incentive pay

Idaho Power's adjustment to the test year for employee incentive pay will be excluded. This will result in a revenue requirement deduction of $288,000.

g. Payroll salary structure

Idaho Power's payroll will be adjusted to reflect that a proposed 3% salary increase for 2003 did not occur but that a 3.5% general wage adjustment in 2005 did occur. This adjustment will result in no change to Idaho Power's proposed revenue requirement.

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h. Wage and salary adjustment

Idaho Power's test period wages and salary will be adjusted in accordance with guidelines followed in previous rate cases. This will result in a revenue requirement deduction of $32,000.

i. Hells Canyon Complex legal costs

Capitalized legal costs from 2001 are excluded. This results in a revenue requirement deduction of $4000.

j. Rate base additions annualized

Costs for projects closed in December 2003 and included as annualized adjustments in Idaho Power's rate base will be adjusted consistent with other additions made in the test year. This will result in a revenue requirement deduction of $34,000.

k. Prepaid pension expenses

Costs for prepaid pension expenses will be removed from rate base. This results in a revenue requirement deduction of $93,000.

Non-revenue requirement issues

10. The Parties agree to the following non-revenue requirement adjustments and matters:

a. Marginal cost adjustment

i. Idaho Power will replace the actual 2003 uncollectible expense for each class with the average of actual expenses for the four years 2001 through 2004.

b. Service Establishment Charge

i. Idaho Power will eliminate its proposal to add a $20 service establishment charge described at Idaho Power/Exhibit 34T, Bowman/Pages 6-8.

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c. Audit recommendations

i. Pursuant to ORS 757.495 and OAR 860-027-0040, Idaho Power will file an application for approval of the service agreement for those administrative services furnished to Idaho Power by affiliates and for services provided by Idaho Power to affiliates.

ii. Pursuant to OAR 860-027-0041, Idaho Power will file an informational filing concerning construction services provided to IDACOMM.

iii. Pursuant ORS 757.495 and OAR 860-027-0040, Idaho Power will file an application for approval of short-term borrowing from its affiliate, Idaho Energy Resources Co.

iv. Pursuant to ORS 757.480 and OAR 860-027-0025, Idaho Power shall file an application for Commission approval of its Boise Bench Transmission Station Land Sale (2000) and State Street Office Sale (2001) and any other property sale for which the value of the property sold exceeded, or will exceed, $100,000.

v. Idaho Power will improve its accounting processes to properly classify lobbying expenses to non-utility accounts when the expenses are initially recorded on its books.

d. Conservation

i. Idaho Power will seek approval from the Commission to implement the same type of mechanism and the same level of commitment as ultimately approved by the Idaho Commission to fund energy efficiency programs such as those listed in Attachment A to this Stipulation. The amount of the conservation rider will be equal to the rider amount approved by the IPUC in Order No. 29784.

12. The Parties agree that the Stipulation represents a compromise in the positions of the parties.

13. The Stipulation will be offered into the record of the above-captioned docket pursuant to OAR 860-014-0085. The Parties agree to support the Stipulation throughout this proceeding and any appeal, provide witnesses to sponsor the Stipulation at any hearing held in the above-captioned docket and recommend that the Commission issue an order adopting the settlement contained herein.

14. The Parties have negotiated the Stipulation as an integrated document. If the Commission rejects all or any material portion of the Stipulation, or conditions its approval upon the imposition of additional material conditions, any party disadvantaged by such action shall have the rights provided in OAR 860-014-0085 and shall be entitled to seek reconsideration of the Commission's order.

15. By entering into the Stipulation, no party shall be deemed to have approved, admitted or consented to the facts, principles, methods or theories employed by any other party in arriving at the terms of the Stipulation. No party shall be deemed to have agreed that any part of the Stipulation is appropriate for resolving issues arising in any other proceeding.

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(503) 378-6322

16. The Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

By: ______________________
Stephanie Andrus

Date: May 20, 2005

CITIZENS' UTILITY BOARD

By: ______________________
Bob Jenks

Date: ______________________

IDAHO POWER COMPANY

By: ______________________
Lisa Rackner

Date: ______________________

OREGON INDUSTRIAL CUSTOMERS OF IDAHO POWER

By: ______________________
Peter Richardson

Date: ______________________

Department of Justice
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Salem, OR 97301-4096
(503) 378-6322

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STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

By: ______________________
Stephanie Andrus

Date: ______________________

CITIZENS' UTILITY BOARD

By: Robert Jenks
Bob Jenks

Date: 5/19/05

IDAHO POWER COMPANY

By: ______________________
Lisa Rackner

Date: ______________________

OREGON INDUSTRIAL CUSTOMERS OF IDAHO POWER

By: ______________________
Peter Richardson

Date: ______________________

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(503) 378-6322

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STAFF OF THE PUBLIC UTILITY COMMISSION OF OREGON

By: s/Stephanie Andrus
Stephanie Andrus

Date: May 20, 2005

CITIZENS' UTILITY BOARD

By: ______________________
Bob Jenks

Date: ______________________

IDAHO POWER COMPANY

By: Sarah Wallace for
Lisa Rackner

Date: July 27, 2005

OREGON INDUSTRIAL CUSTOMERS OF IDAHO POWER

By: ______________________
Peter Richardson

Date: ______________________

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(503) 378-6322

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STAFF OF THE PUBLIC UTILITY
COMMISSION OF OREGON

By: s/Stephanie Andrus
Stephanie Andrus

Date: May 20, 2005

CITIZENS' UTILITY BOARD

By: ____________
Bob Jenks

Date: ____________

IDAHO POWER COMPANY

By: ____________
Lisa Rackner

Date: ____________

OREGON INDUSTRIAL
CUSTOMERS OF IDAHO POWER

By: Peter J. Richardson
Peter Richardson

Date: July 27, 2005

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 378-6322

IDAHO POWER - UE 167
OREGON ALLOCATED RESULTS OF OPERATIONS
TEST PERIOD ENDING DECEMBER 2003
($000)

	SUMMARY SHEET	2003 Results Per Company Filing (1)	Adjustments (2)	2003 Adjusted (3)	Required Change for Reasonable Return (4)	Results at Reasonable Return (5)
1	**Operating Revenues**					
2	Retail Sales	$25,220	$0	$25,220	$597	$25,817
3	Wholesale Sales	3,116	2,537	5,653	0	5,653
4	Other Revenues	1,855	23	1,878	0	1,878
5	**Total Operating Revenues**	$30,191	$2,560	$32,751	$597	$33,348
6	**Operating Expenses**					
7	Steam Production	$6,434	$0	$6,434	$0	$6,434
8	Hydro Production	1,190	(49)	1,141	0	1,141
9	Other Power Supply	3,599	93	3,692	0	3,692
10	Transmission	883	0	883	0	883
11	Distribution	2,646	0	2,646	0	2,646
12	Customer Accounting	838	0	838	0	838
13	Customer Service & Info	233	0	233	0	233
14	Sales	0	0	0	0	0
15	Administrative and General	3,308	(452)	2,856	0	2,856
16	**Total Operation & Maintenance**	$19,131	($408)	$18,723	$0	$18,723
17	Depreciation	$4,506	($11)	$4,495	$0	$4,495
18	Amortization	489	0	489	0	489
19	Taxes Other than Income	1,495	0	1,495	2	1,497
20	Income Taxes	788	1,184	1,972	232	2,204
21	Miscellaneous Revenue and Expense	(342)	0	(342)	0	(342)
22	**Total Operating Expenses**	$26,066	$765	$26,831	$234	$27,065
23	**Net Operating Revenues**	$4,125	$1,795	$5,920	$363	$6,283
24	**Average Rate Base**					
25	Electric Plant in Service	$157,928	($798)	$157,130	$0	$157,130
26	Accumulated Depreciation & Amortization	(68,493)	44	(68,449)	0	(68,449)
27	Accumulated Deferred Income Taxes	(11,456)	0	(11,456)	0	(11,456)
28	Accumulated Deferred Inv. Tax Credit		0	0	0	0
29	**Net Utility Plant**	77,979	($754)	$77,225	$0	$77,225
30	Plant Held for Future Use	0	0	0	0	0
31	Acquisition Adjustments	0	0	0	0	0
32	Working Capital	765	29	794	3	797
33	Fuel Stock	324	0	324	0	324
34	Materials & Supplies	1,020	0	1,020	0	1,020
35	Customer Advances for Construction	(53)	0	(53)	0	(53)
36	Weatherization Loans		0	0	0	0
37	Prepayments	860	(860)	0	0	0
38	Misc. Deferred Debits	186	0	186	0	186
39	Misc. Rate Base Additions/(Deductions)	711	0	711	0	711
40	**Total Average Rate Base**	$81,792	($1,585)	$80,207	$3	$80,210
41	**Rate of Return**	5.04%		7.38%		7.83%
42	**Implied Return on Equity**	3.93%		9.02%		10.00%

IDAHO POWER - UE 167
OREGON ALLOCATED RESULTS OF OPERATIONS
TEST PERIOD ENDING DECEMBER 2003
($000)

		Income Tax Calculations	2003 Per Company Filing (1)	Adjustments (2)	2003 Adjusted (3)	Required Change for Reasonable Return (4)	Results at Reasonable Return (5)
1		Book Revenues +IERCO Income	$30,514	$2,560	$33,074	$597	$33,671
2		Book Expenses Other than Depreciation	20,626	(408)	20,218	2	20,220
3		State Tax Depreciation	5,008	(11)	4,997	0	4,997
4		Interest	2,960	(51)	2,909	0	2,909
5	Less:	Schedule M Differences	(46)	0	(46)	0	(46)
6		State Taxable Income	$1,966	$3,030	$4,997	$595	$5,592
7		State Income Tax	$85	$191	$276	$37	$313
8		State Tax Credits	0	0	0	0	0
9		Net State Income Tax	$85	$191	$276	$37	$313
10		IERCO INCOME Adjustment	$323	$0	$323	$0	$323
11	Plus:	Other Schedule M Differences	64	0	64	0	64
12		Federal Taxable Income	$1,579	$2,839	$4,419	$558	$4,977
13		Federal Tax @ 35%	$553	$993	$1,546	$195	$1,741
14		Federal Tax Credits	0	0	0	0	0
15		Current Federal Tax	$553	$993	$1,546	$195	$1,741
16		ITC Adjustment	$0	$0	$0	$0	$0
17		Prior Year Defficiency	60	0	60	0	60
18		Restoration	15	0	15	0	15
19		Total ITC Adjustment	$45	$0	$45	$0	$45
20		Provision for Deferred Taxes	$105	$0	$105	$0	$105
21		Total Income Tax	$787	$1,184	$1,971	$232	$2,203

IDAHO POWER - UE 167
OREGON ALLOCATED RESULTS OF OPERATIONS
TEST PERIOD ENDING DECEMBER 2003
($000)

REVENUE SENSITIVE COSTS	
Revenues	1.00000
Operating Revenue Deductions	
Uncollectible Accounts	0.00000
Taxes Other - Franchise	0.00394
- Other	0.00000
- Resource supplier	0.00000
State Taxable Income	0.99606
State Income Tax	0.06275
Federal Taxable Income	0.93331
Federal Income Tax @ 35%	0.32666
ITC	0.00000
Current FIT	0.32666
Other	0.00000
Total Excise Taxes	0.38941
Total Revenue Sensitive Costs	0.39335
Utility Operating Income	0.60665
Net-to-Gross Factor	**1.648**

COST OF CAPITAL - STAFF	% of CAPITAL	COST	WEIGHTED COST
Long Term Debt	54.03%	5.99%	3.24%
Preferred Stock	0.00%	0.00%	0.00%
Common Equity	45.97%	10.00%	4.60%
Total	100.00%		**7.83%**

IDAHO POWER - UE 167
ADJUSTMENTS TO OREGON ALLOCATED RESULTS
TEST PERIOD ENDING DECEMBER 2003
($000)

	Adjustments	Rate Base Adjust to K&M changes (S-1)	Net Power Supply adj. (S-2)	Cloud Seeding Costs (S-3)	Non-labor A & G Expenses (S-4)	Employee Incentive Pay K&M (S-5)	3% Payroll Salary increase K&M (S-6)	Wage & Salary Adjustment (S-7)	Hells Canyon Legal Costs (S-8)	Annualized Rate Base Additions (S-9)	Prepaid Pension Expense (S-10)	Total Adjustments (Base Rates)
1	**Operating Revenues**											
2	Retail Sales	0	0	0	0	0	0	0	0	0	0	0
3	Wholesale Sales	0	2,537	0	0	0	0	0	0	0	0	2,537
4	Other Revenues	23	0	0	0	0	0	0	0	0	0	23
5	**Total Operating Revenues**	**$23**	**$2,537**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$2,560**
6	**Operating Expenses**											
7	Steam Production	0	0	0	0	0	0	0	0	0	0	0
8	Hydro Production	0	0	(49)	0	0	0	0	0	0	0	(49)
9	Other Power Supply	0	93	0	0	0	0	0	0	0	0	93
10	Transmission	0	0	0	0	0	0	0	0	0	0	0
11	Distribution	0	0	0	0	0	0	0	0	0	0	0
12	Customer Accounting	0	0	0	0	0	0	0	0	0	0	0
13	Customer Service & Info	0	0	0	0	0	0	0	0	0	0	0
14	Sales	0	0	0	0	0	0	0	0	0	0	0
15	Administrative and General	0	0	0	(186)	(234)	0	(32)	0	0	0	(452)
16	**Total Operation & Maintenance**	**$0**	**$93**	**($49)**	**($186)**	**($234)**	**$0**	**($32)**	**$0**	**$0**	**$0**	**($408)**
17	Depreciation	0	0	0	0	(11)	0	0	0	0	0	(11)
18	Amortization	0	0	0	0	0	0	0	0	0	0	0
19	Taxes Other than Income	0	0	0	0	0	0	0	0	0	0	0
20	Income Taxes	9	955	19	73	100	0	13	0	4	11	1,184
21	Miscellaneous Revenue and Expense	0	0	0	0	0	0	0	0	0	0	0
22	**Total Operating Expenses**	9	1,048	(30)	(113)	(145)	0	(19)	0	4	11	765
23	**Net Operating Revenues**	**$14**	**$1,489**	**$30**	**$113**	**$145**	**$0**	**$19**	**$0**	**($4)**	**($11)**	**$1,795**
24	**Average Rate Base**											
25	Electric Plant in Service	0	0	(25)	0	(374)		(5)	(29)	(365)	0	(798)
26	Accumulated Depreciation & Amortization	0	0	0	0	0	0	0	0	44	0	44
27	Accumulated Deferred Income Taxes	0	0	0	0	0	0	0	0	0	0	0
28	Accumulated Deferred Inv. Tax Credit	0	0	0	0	0	0	0	0	0	0	0
29	**Net Utility Plant**	**$0**	**$0**	**($25)**	**$0**	**($374)**	**$0**	**($5)**	**($29)**	**($321)**	**$0**	**($754)**
30	Plant Held for Future Use	0	0	0	0	0	0	0	0	0	0	0
31	Acquisition Adjustments	0	0	0	0	0	0	0	0	0	0	0
32	Working Capital	0	42	(1)	(5)	(6)	0	(1)	0	0	0	29
33	Fuel Stock	0	0	0	0	0	0	0	0	0	0	0
34	Materials & Supplies	0	0	0	0	0	0	0	0	0	0	0
35	Customer Advances for Construction	0	0	0	0	0	0	0	0	0	0	0
36	Weatherization Loans	0	0	0	0	0	0	0	0	0	0	0
37	Prepayments	0	0	0	0	0	0	0	0	0	(860)	(860)
38	Misc. Deferred Debits	0	0	0	0	0	0	0	0	0	0	0
39	Misc. Rate Base Additions/(Deductions)	0	0	0	0	0	0	0	0	0	0	0
40	**Total Average Rate Base**	**$0**	**$42**	**($26)**	**($5)**	**($380)**	**$0**	**($6)**	**($29)**	**($321)**	**($860)**	**($1,585)**
41	**Revenue Requirement Effect**	**($23)**	**($2,449)**	**($52)**	**($187)**	**($288)**	**$0**	**($32)**	**($4)**	**($34)**	**($93)**	**($3,162)**

IDAHO POWER - UE 167
ADJUSTMENTS TO OREGON ALLOCATED RESULTS
TEST PERIOD ENDING DECEMBER 2003
($000s)

	Income Tax Calculations	Rate Base Adjust to K&M changes (S-1)	Net Power Supply adj. (S-2)	Cloud Seeding Costs (S-3)	Non-labor A & G Expenses (S-4)	Employee Incentive Pay K&M (S-5)	3% Payroll Salary increase K&M (S-6)	Wage & Salary Adjustment (S-7)	Hells Canyon Legal Costs (S-8)	Annualized Rate Base Additions (S-9)	Prepaid Pension Expense (S-10)	**Total Adjustments (Base Rates)**
1	Book Revenues	$23	$2,537	$0	$0	$0	$0	$0	$0	$0	$0	$2,560
2	Book Expenses Other than Depreciation	0	93	(49)	(186)	(234)	0	(32)	0	0	0	($408)
3	State Tax Depreciation	0	0	0	0	(11)	0	0	0	0	0	($11)
4	Interest	0	1	(1)	(0)	(12)	0	(0)	(1)	(10)	(28)	($51)
5	Schedule M Differences		0	0	0	0	0	0	0	0	0	$0
6	State Taxable Income	$23	$2,443	$50	$186	$257	$0	$32	$1	$10	$28	$3,030
7	State Income Tax	$1	$154	$3	$12	$16	$0	$2	$0	$1	$2	$191
8	State Tax Credits	0	0	0	0	0	0	0	0	0	0	$0
9	Net State Income Tax	$1	$154	$3	$12	$16	$0	$2	$0	$1	$2	$191
10	Additional Tax Depreciation	0	0	0	0	0	0	0	0	0	0	$0
11	Other Schedule M Differences	0	0	0	0	0	0	0	0	0	0	$0
12	Federal Taxable Income	$22	$2,289	$47	$174	$241	$0	$30	$1	$9	$26	$2,839
13	Federal Tax @ 35%	8	801	16	61	84	0	11	0	3	9	$993
14	Federal Tax Credits	0	0	0	0	0	0	0	0	0	0	$0
15	Current Federal Tax	$8	$801	$16	$61	$84	$0	$11	$0	$3	$9	$993
16	**ITC Adjustment**											$0
17	Deferral	0	0	0	0	0	0	0	0	0	0	$0
18	Restoration	0	0	0	0	0	0	0	0	0	0	$0
19	Total ITC Adjustment	0	0	0	0	0	0	0	0	0	0	$0
												$0
20	Provision for Deferred Taxes	0	0	0	0	0	0	0	0	0	0	$0
												$0
21	Total Income Tax	$9	$955	$19	$73	$100	$0	$13	$0	$4	$11	$1,184

UE 167 Final Order.xls