RICHARDSON & O'LEARY
ATTORNEYS AT LAW

Peter Richardson

Tel: 208-938-7901 Fax: 208-938-7904
peter@richardsonandoleary.com
P.O. Box 7218 Boise, ID 83707 - 515 N. 27th St. Boise, ID 83702

March 17, 2005

Christina Smith
Administrative Law Judge
Oregon Public Utilities Commission
P.O. Box 2148
Salem, Oregon 97308-2148

Re: DOCKET NO. UE 167

Dear Judge Smith:

Please accept the enclosed filing, which was inadvertently omitted from our electronic mailing on March 15, 2005. We have electronically filed that with your Filing Center today.

An original and five copies were mailed, via U.S. Postal Service, on March 15, 2005, as well. We are enclosing another two copies, per our conversation with your assistant, Annette, this morning.

We appreciate your understanding, and thank you for your assistance.

Sincerely,

Peter J. Richardson

Encl.

BEFORE THE PUBLIC UTILITIES
COMMISSION OF OREGON

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	))))))	UE-167

Direct Testimony of

Don C. Reading, Ph.D.

Ben Johnson Associates, Inc.

on behalf of

Oregon Industrial Customers

March 15, 2005

Introduction

Q. Would you please state your name and address?

A. Don Reading, Ben Johnson Associates, Boise, Idaho

Q. Have you prepared an appendix that describes your qualifications in regulatory and utility economics?

A. Yes. Appendix A, attached to my testimony, serves this purpose.

Q. Does your testimony include any attachments?

A. Yes. Attached are Exhibit OICIP No. 1: Danskin Station Costs, and Exhibits OICIP No. 2 and OICIP No. 3: Mid-Columbia Prices.

Q. What is your purpose in making your appearance at this hearing?

A. Our firm has been retained by the Oregon Industrial Customers of Idaho Power ("OICIP") to assist in the evaluation of Idaho Power's ("Company," or "IPCo") rate application filed in Docket UE-167. General rate applications are usually complex, and that is certainly true of this case. I have reviewed the Company's testimony and exhibits, as well as the discovery filed by parties to this docket and the Company's responses.

Q. Would you please describe how your testimony is organized?

A. Yes. Following this introduction, my testimony has six major sections. The first section deals with the costs and assumed operating hours of the Company's Danskin Station Generating Facility. The second section discusses a novel way the Company can address some of its peaking load problems without relying on expensive gas fired simple cycle plants. The third section addresses the Company's time of use rate proposal. In the fourth section I discuss some of the problems associated with the Company's power supply model. The fifth section addresses power quality problems my clients are suffering. Finally, in the sixth section I address the need to permit industrial customers to self direct their conservation dollars.

Q. Lets turn to your first major section which is the impact on proposed rates from the inclusion of Idaho Power's Danskin Generating Station located in Mt. Home. Based on the Company's Exhibits did you examine the contribution of the Danskin Station to Idaho Power's generating resources?

A. Yes. Company Exhibit 13 estimates power supply costs and the output of all Idaho Power's current generation assets given current system demand for each year for the period 1928 through 2003. The output and power supply costs are thus normalized over the 75 year period for the water conditions that existed for that given year. An average is calculated that would represent the mean or expected output and power supply costs under normal water conditions to meet native load. Dasnkin station's normalized average annual output over this 75 year period is 804.6 Mwh or the equivalent of just 8.9 hours per year. (Idaho Power's Exhibit 13, page 1 of 77; hours based on 90 MW) At this output the fuel costs including the Fixed Capacity Charge - Gas Transportation is $3.267 million. If you add the annual capital costs of $7.728 million (Idaho Power Company, Application to the Idaho Public Utilities Commission, Case No. IPC-E-03-13, p. 7. "The annual revenue requirement associated with the construction of this peaking generating resource is $7,727,782.") This leads to an average normalized annual cost of $10.995 million. The normalized average cost per kilowatt hours basis (kWh) (<u>not MWh</u>!) is $13.65.

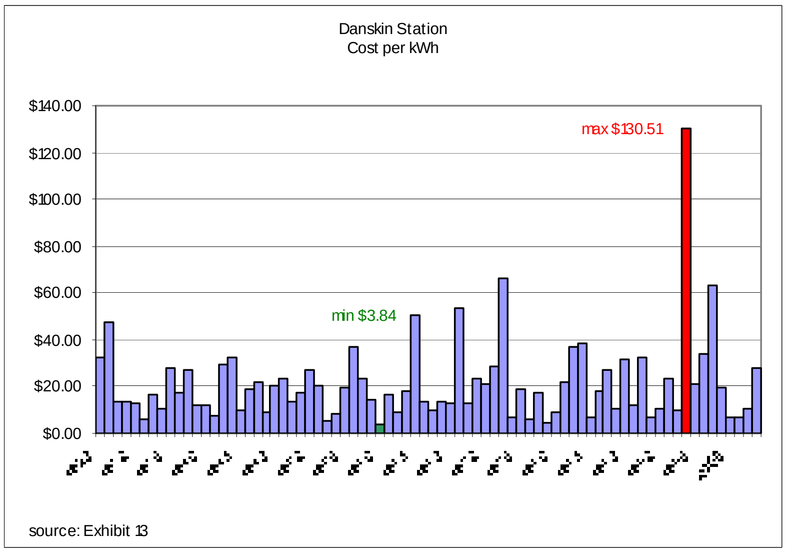


Chart 1

In fact, as shown in the Chart 1 above and in Exhibit OICIP No. 1 over the normalized 75 year period, the highest Mwh production from Danskin Station was found by the Company to be 2,886.3 MWh in 1960 for a cost of $3.84 per kWh for that year. The highest cost per kWh is $130.51 in 1995.

Q. Could you briefly describe the Danskin Generation Station?

A. The generating plant consists of two (2) natural gas-fired combustion turbines rated at approximately 45 MW each (Unit #2 and Unit #3). It is located about two miles from Mountain Home, Idaho and first produced power in September 2001. It is supplied by gas from the Williams Northwest Pipeline located near the plant. Due to air quality standards the plant is limited in operations to 5,140 hours per year.

Q. The Plant has been in operation since the fall of 2001. What has been the actual output of the facility?

A. This gas fired unit was constructed during the summer of 2001. For calendar 2002, the first full year of operation, output from Danskin was 43,368 Mwh (FERC Form 1, 2002, page 403) Production costs listed for calendar 2002 are $5.14 million which yields a running cost of 11.85 cents per kWh. In 2003 production costs for Danskin were $6.61 million with an output of 47,793 Mwh. (FERC Form 1, 2003, page 403.) This yields a variable cost of 15.81 cents per kWh. However this does not include the annual capital costs of $7.7 million. Including annual capital costs yields an all-in cost of 29.7 cents per kWh for 2002 and 34.30 cents per kWh in calendar year 2003.

It should be remembered --- and an economists favorite saying -- sunk costs are sunk. From the Company's prospective (and from an economically rational perspective, once the plant is built) the annual amortized cost of $7.7 million does not matter in deciding when to operate the plant. As long as the variable costs -- primarily natural gas prices for a unit like this -- are covered by the market value of power it will be rational to run the plant. The variable costs of the power produced from Danskin have varied between 60.2 cents per kWh in 2001 and 29.7 cents per kWh in 2002. However ratepayers in this case are also being asked to bear the burden of the capital costs in their rates. From the ratepayers prospective therefore the full cost – both variable and fixed – is the relevant cost.

Q. Company witness Said testified that the Idaho Public Utilities Commission issued a Certificate of Public Convenience and Necessity (CPCN) for the Danskin Power Plant. (Said Direct Testimony, UE-167, and Exhibit 12T, p8.) How do the costs you discussed above compare to what the Company told the Idaho Commission in their application for a (CPCN) about the operation of the plant?

A. In its CPCN Application in Idaho the Company described the expected operating costs of Danskin Station as follows:

> The preliminary estimate of the levelized cost per megawatt hour (MWh) would range from an upper level of $223 per MWh based on a capital cost for the Station of $55.2 million, 500 hours of annual generation, and levelized fuel costs of $5.05 per MMBtu over the 30-year life of the Station, to a lower range cost of $77 per MWh based on a Station cost of $46 million, 5,140 hours of annual dispatch, and average fuel costs of $5.05 per MMBtu. (Idaho Public Utilities Commission Order No. 28773, Case No. IPC-E-01-12, July 11, 2001, page 5.)

This means that the actual cost of 29.7 cents per kWh for 2002 was 33% higher than the highest estimated cost, and 385% higher than the lowest estimate. For 2003 the actual costs of 34.3 cents per kWh would mean the range would be 65% higher than the highest cost estimate and 445% higher than the lowest expected cost. It should be remembered that both 2002 and 2003 were low water years when output of the plant would be expected to be high and hence the cost per kWh would be expected to be on the low end of the range.

Q. How does the estimated cost range for Danskin output found in the Company's CPCN compare to the normalized range presented by the Company in this case?

A. As shown above and in Exhibit OICIP No. 1 the normalized range over the 75 year period presented by the Company in this case varies from a low of $3.84 per kWh to a high of $130.51 per kWh. This translates into 1,285% higher than what Idaho Power asserted the plant would operate at - and on the low end 43,943% higher on the high end. So both the actual and expected costs significantly exceed the Company's expected costs. The costs of production on a kWh basis are highly dependent on the number of hours the facility is in operation. It appears that even in dry years that have occurred since the plant came on line it will not be operated in a range that will produce power at a reasonable cost.

Q. You explained above that on a normalized basis to meet native load, the cost of output from Danskin the Company estimates range from a low of $3.84 per kWh to a high of $130.51 per kWh. Why are these costs so much higher than predicted by the Company?

A. Based on both actual operations and expected needs to meet native load, the hours of operation are significantly less than Idaho Power claimed they would operate the plant. The Idaho Commission found that:

> For the immediate future, Idaho Power indicates that it intends to operate the Station 5,140 hours per year, i.e., up to the limit allowed by its air quality permit. Once the Garnet project comes on line in 2004, however, the role of the Mountain Home Station, Staff states, could change. (IPUC Order No. 28773, Case No. IPC-E-01-02, page 7.)

Therefore the Company expected the plant to be on line for over 5,000 hours annually through 2004. In reality the plant was connected to load 358 hours in 2001, 753 hours in 2002, and 837 hours in 2003. (FERC Form 1, 2001 through 2003, page 403.) Through October of 2004 one unit has operated 287 hours and the other unit 302 hours. (Idaho Power's Response to Request Staff 227.) This means the plant has operated significantly less than expected since it came on line. Because the hours of operation have been so limited the cost of output on a kWh basis is very high.

Q. Do you know why the hours of operation of Danskin Station have been so limited?

A. The Company probably assumed it would use the plant for secondary sales as well as to meet native load needs. This would mean the plant would be on line sufficient hours to bring the costs on a kWh basis in line with what the Company expected would be the costs of power. Idaho Power made the following declaration in its Application for approval of Danskin in Idaho:

> Idaho Power's marketing and trading analysts have indicated that annual heavy load period market prices for the next few years will likely be in the range of $50 to $350 per MWh. The estimated forward price is approximately $350 per MWh for April 1 through March 2002. The five to ten years forward prices currently are in the range of $55 per MWh. Hourly prices have historically been several times the annual average and could be in excess of $1000 per MWh in the near term. (Idaho Power Application, Case No. IPC-E-01-12, page 4.)

Note this reference is to the Company's marketing and trading arm. In reality, prices in the secondary market have not been as high as the Company predicted. What is irrational about the Company's estimates is the assumption that the upper range could be sustained for any extended period of time. At prices equal to 35 cents per kWh the market would be expected to adjust with customer curtailments and fuel switching. Even if Danskin would have been on line the full 5,140 hours per year, market prices would need to be above $77 per MWh for the plant to be cost effective for secondary sales.

Q. You indicated that Danskin would be used for secondary sales as well as to meet native load needs. What has been the experience since the plant came on line?

A. Specific units are generally not identified when making off system sales. The Company states that Danskin is their most expensive resource:

> Danskin, as the Company's most expensive variable cost resource, is the last Company resource utilized to serve load. (Idaho Power's Response to Request Staff 227.)

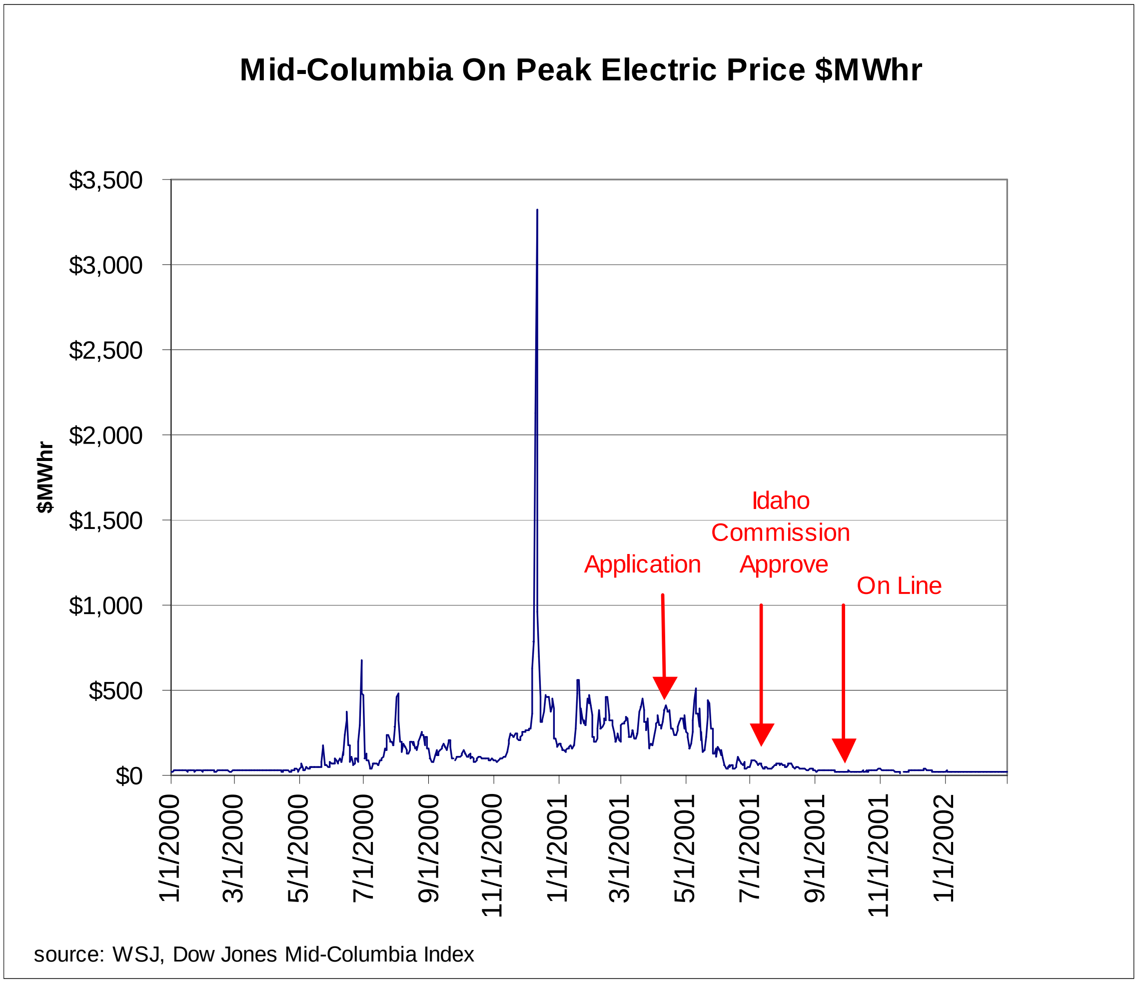
Therefore only if electric prices are very high would Danskin be used for secondary sales. Since the electric crisis in 2000, and the first few months of 2001, electric prices have not held at the level the Company anticipated.

Q. Wouldn't it be fair to look at the decision in the context of the chaos in the energy markets in 2000 and 2001?

A. Certainly. The turmoil in energy markets during the 2000 and the first half of 2001 are well known. In the fall of 2000 and early 2001 the Company had engaged in several programs to obtain power, including industrial and irrigation buy backs, in order to obtain power needed to serve load. As indicated in the Chart 2 (Exhibit OICIP No. 2, page 1.) below, prices for electricity on the market reached unprecedented levels in December 2001 and remained high through the spring of 2001.

Chart 2

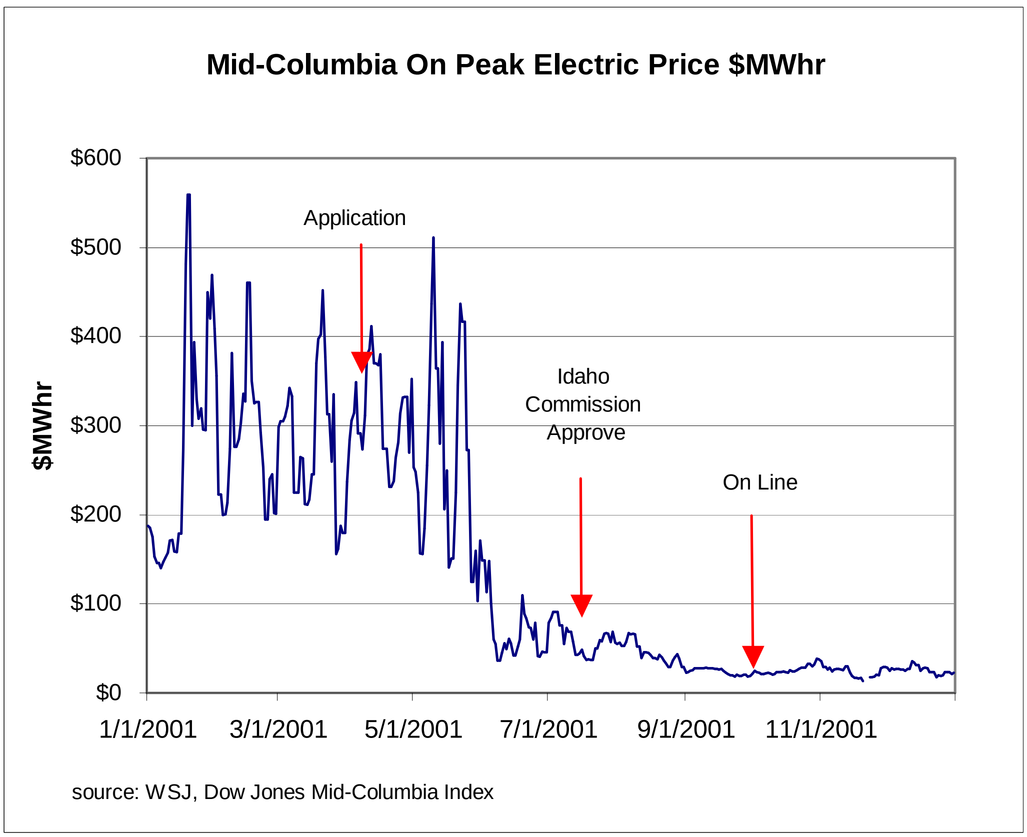
Q.


Mid-Columbia On Peak Electric Price $MWhr
$MWhr
$3,500
$3,000
$2,500
$2,000
$1,500
$1,000
$500
$0
1/1/2000
3/1/2000
5/1/2000
7/1/2000
9/1/2000
11/1/2000
1/1/2001
3/1/2001
5/1/2001
7/1/2001
9/1/2001
11/1/2001
1/1/2002
Application
Idaho
Commission
Approve
On Line
source: WSJ, Dow Jones Mid-Columbia Index

2 you have indicated the date the application for Danskin was filed, the date the Commission approved IPCo's CPCN, and the on line date. It looks like market prices had changed dramatically by the time the Idaho Commission issued its Danskin CPCN Order. Could you be more specific?

A. Yes. Chart 3 (Exhibit OICIP No. 3) below shows for the year 2001 the Dow Jones Mid-Columbia Index, The Company's application date, the date the Idaho Commission approved the application, and the on line date for Danskin.

Chart 3



Note that by the time the Idaho Commission approved the CPCN, market conditions had changed dramatically. Also note that by the time the plant came on line, the price for market power was back to pre-2000 levels. This meant the ability to run the plant and make a profit diminished even when including only the variable expenses and not the fixed costs. It also shows that prices were not remaining at the $350 per Mwh through March 2002 as predicted by Idaho Power's marketing and trading analysts. This should have served as a warning to the Company that it needed to reassess the economic viability of the plant. As discussed below, the Idaho Commission had asked for more information and documentation about the facility. It would have been wise for the Company to reassess its decision to go forward with this plant at the time of the Idaho Commission's approval.

Q. Did the Danskin Generating Station fit within the Company's Integrated Resource Plan (IRP)?

A. Idaho Power acknowledged during the application process that Danskin was not part of their IRP:

> Idaho Power acknowledges that the Mountain Home Station [Danskin] is not identified in the Near-Term Action Plan in the Company's 2000 IRP. Nevertheless, Idaho Power believes that construction of the Station is consistent with the IRP. The Station provides a cost-effective alternative to planned wholesale market purchases. Idaho Power believes that recent market prices for purchased power create a unique circumstance to be addressed for the 2001-2004 period. (Idaho Power Application, Case No. IPC-E-01-12, page 4.)

The Idaho Commission in approving Danskin recognized what it characterized as 'volatility' in the electric spot market that could mean deviation from the IRP would be justified. However the Commission also firmly stated that there was not sufficient information available to make a least cost decision:

> We are convinced that the volatility of the electric spot market

> created a situation that justified a deviation from the Company's 2000 IRP and its actions in developing plans for the Mountain Home Station. The information provided however is insufficient to determine the reasonableness of the related costs. As reflected in Staff comments, it is unknown whether the Mountain Home Station was the least cost alternative. Because the Mountain Home Station was not selected pursuant to a RFP process, we are unable to conclude based on the information provided that the commitment estimate is reasonable. The Company in its Application, we note, also provides no comparison of alternatives (alternatives available but not chosen). As reflected in its comments, Power Development Associates believes it offered the Company a better project. Communication and timing appear to be factors in the Company's decision to proceed with its own project. It also appears that the Company's choice of equipment may be better suited to later conversion to combined cycle. There is no record as to whether other alternatives were also considered and rejected. We are unconvinced that the best measure of the cost of alternative resources is market price estimates in effect at the time the decision to proceed was made. The record supporting such a finding remains to be developed. (IPUC Order No. 28773, Case No. IPC-E-01-02, page 12.)

Rather than operating at 5,000 hours per year, the Company now represents the resource as operating only as a "resource of last resort". (Said Direct Testimony, UE-167, Exhibit 12T, p. 13.)

Q. Mr. Said in his direct testimony states the Company has recently received a CPCN from the Idaho Commission for the Bennett Mountain generating facility. Could you briefly describe this unit?

A. The Bennett Mountain plant is a 162MW natural gas-fired, simple cycle facility located in Mountain Home, Idaho. The site is approximately four miles southeast of the Danskin generating plant. The Bennett Mt. plant is expected to be on line in June, 2005. The firm bid price for the project is $44.6 million. With the addition of start-up costs, change orders, and other unforeseen events, Idaho Power made a "Commitment Estimate" in its application to the Idaho Commission of $54 million for the plant. (IPUC Order No.

29410, Case No. IPC-E-03-12, page 4.) The Idaho Commission found:

> Assuming a 20% capacity factor over the 30-year expected life of the plant, Staff calculated an energy cost of approximately $44.60 per MWh, with all other factors being equal. We further find the base price of $44.6 million for the 162 MW Bennett Mountain project compares favorable to the $49 million cost of the 90 MW Danskin plant completed in 2001. (IPUC Order No. 29410, Case No. IPC-E-03-12, page 10.)

The Bennett Mountain plant has 72 more MW production capability than Danskin and cost $4.4 million less. Because Bennett Mountain is a lower cost resource, once it comes on line the Danskin will produce even less than it has in the past three years.

Q. What recommendations do you have for this Commission in dealing with the very high cost the Company is asking Oregon's ratepayers to shoulder in relation to the Danskin Generating Station?

A. Certainly market conditions have changed but the magnitude of the cost difference that the Company is asking ratepayers to pay and the exceptions presented to the Commission are huge. It is unreasonable to expect ratepayers to pay this amount. The Company did have the alternative of reassessing but pushed ahead even while the market prices were declining.

I recommend the Commission not give the Company rate base treatment for Danskin Station. This recommendation is underscored by the fact that the Company is going ahead with the Bennett Mountain plant that will cause Danskin to run even less.

Distributive Generation Potential

Q. Idaho Power's last rate case was ten years ago. How do the Company's loads compare to those that existed at the time of its the last general rate case?

A. As surprising as it may sound, energy consumption from native load is virtually the same as it was 10 years ago.

> The Company's 1993 annual normalized system load used in the UE 92 case was 14.5 million megawatt-hours (MWh). The Company's 2003 annual normalized system load used in this case is 14.1 million MWh. The annual system load served today is approximately the same as it was ten years ago. (Idaho Power Direct Testimony of Greg Said, page 2.)

On a normalized basis, consumption demand actually declined by 100,000 kWh annually. The major reason for this change has been the loss of the Astaris (FMC) load of 1.7 million MWh. In addition, the Company has phased out FERC jurisdictional contract loads. While total load is flat compared to 10 years ago, there have been significant shifts in use from various customer classes. These shifts have led to a substantial change in the load profile of the Company:

> The FMC contract as well as the concluded FERC contracts that existed ten years ago provided the Company with relatively consistent monthly loads that were somewhat flat throughout the year. The FMC load had an interruptible component. Load growth within the various customer classes has tended to be much more seasonal and dependent upon weather. As a result of the loss of relatively flat loads and the addition of non-interruptible seasonal loads, the Company's recently filed 2004 Integrated Resource Plan now shows the need for summer peaking resources (June, July, and August) and winter peaking resources (November and December). (Idaho Power Direct Testimony of Greg Said, page 3,4.)

Over this same time period, Idaho Power's Oregon loads have grown by 23.7% from 536,125 MWh to 696,678 MWh. This is consistent with load growth on Idaho Power's system residential and commercial loads. The loss of flat load customers has occurred within the Idaho, not the Oregon, justification.

Q. Does the Company have different concerns relative to the eastern and western side

of its system?

A. Yes. According to the Company:

> However, from a planning perspective, the Company does not like to rely on purchases from the east for several reasons. The first concern is the actual availability of supply on the eastern side of the system. (Idaho Power Direct Testimony of Greg Said, page 14.)

Population and load growth has been higher on the western side of Idaho Power's system. This is a major reason that the peaking plants Danskin and Bennett Mountain are located near the load center in the Boise to Ontario area.

Historically, Idaho Power has maintained that its system was 'energy constrained' not 'capacity constrained'. This was due to the fact that it has a relatively high percent of its generation portfolio in hydro plants and its largest customer (Astaris/FMC) was largely interruptible. The Company could follow peak loads through the manipulation of its dams or through its ability to curtail its largest customer. The loss of the Astaris/FMC interruptible load, and additional operating constraints on its hydro facilities (primarily for environmental concerns) have changed the Company supply resources. In addition, Idaho Power now has a load profile that is more peak sensitive on the demand side which has caused the Company to invest in peaking gas fired generation resources. This is a dramatic change. Both the Danskin Station (proposed for rate basing in this docket) and the proposed Bennett Mountain plant are gas peaking units. Addressing peak has now become a priority for the Company. This is especially true on the western end of Idaho Power's system where the Company has experienced rapid residential and small commercial load growth which magnifies peak demand. This changed load profile causes transmission constraints on the western side of the Company's system. Supplementary generation on the western edge of the system can help provide for a more stable system.

Q. Mr. Said in his direct testimony discusses several ways that the Company is

addressing its peaking concerns. Do you have an additional suggestion that Idaho Power might be able utilize to reduce its need to rely on expensive peaking facilities to meet peak loads, especially on the western side of its system?

A. Yes, I do. A recent report by the Northwest Power Planning Council (Feasibility of Emergency Electrical Generation Units to Serve System Load Requirements, Northwest Power Planning Council, August 17, 2001) found:

> "This study found that emergency generators are available in a variety of commercial and industrial buildings as well as hospitals, high schools, colleges, jails, and public safety facilities. According to industry information Washington, Oregon, Idaho, and Montana have just over 26,000 generators within their borders." [p. 1.]

Q. Are there any emergency generators in Idaho Power's Oregon service territory?

A. Holy Rosary Medical Center in Ontario has two 1 MW emergency generators that could be used to support Idaho Power's system on its western border. This could be a benefit to both Idaho Power and the hospital. The hospital's total load is less than 1 MW. It purchased diesel generators of this size for economic reasons. They own two megawatts for back up and reliability purposes. To test the generators, the medical center needs to pay for an energy sink so that the generators can operate at the required load factor. They essentially run their two megawatt generators and dispose of the power into a ground. These generators could be available on a peaking basis as long as reliability is not compromised.

Q. Are you asking the Commission to take any specific action at this time?

A. Idaho Power has expressed a willingness to investigate the potential of this approach to help in meeting its peak load concerns. We are asking the Commission to 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 variability of using these generators to help meet peak load. The study should include establishing rate designs that would encourage customers with emergency generators to participate in the program.

Time-Of-Use Rates

Q. **The Company has proposed time-of-use (TOU) rates for Schedule 19 customers in Oregon. Is this the same design that was implemented in Idaho?**

A. Idaho Power's proposed Schedule 19 rates in this docket mirror those proposed in its Idaho jurisdiction rate case. The Idaho Commission in its May 2004 Order implemented TOU for Schedule 19 customers after a six month phase-in:

> The Commission approves the Company s proposal for mandatory TOU rates for Schedule 19, but requires a phase-in period before they are implemented. For a period of six months, Idaho Power shall provide two bills to the Schedule 19 customers. The second bill will show the charges that would be incurred under the TOU rates. After six months, Idaho Power can fully implement the TOU rates and bill customers according to the new rates. To accommodate the phase-in period, the Commission approves new rates for Schedule 19 for use during the first six months, and also approves TOU rates for implementation after six months.Public Utilities Commission Order No. 29505, Case No. IPC-E-03-13, May 25, 2004, p. 61.)

These rates have 11 different elements that account for on-, mid-, and off-peak, summer and non-summer, demand, energy, and service charges. This means the Company's time-of-use rates are very complex. They require customers to spend a lot time in order to clearly understand the impacts of the proposed multiple pricing combinations for demand and energy charges in different seasons, different times of the day and different days of the week..

Q. What did the Company find from the "dummy" billing during the phase in period?

A. Idaho Power has determined, after collecting data for the six month period that industrial customer's total bills did not change significantly with the implementation of TOU rates. This data needs to be analyzed to see how industrial customers responded (or did not respond) to the new rate structure. In response to an OICIP production request, Idaho

Power stated:

> . . . the total dollar difference between the flat rates and the TOU rates for the six month period is $13,837 or 0.04 percent of revenue. The dollar impact by customer ranges from a reduction in total billing for the six-month period of $2,204 to an increase in total billing for the six-month period of $3,349. Overall, the TOU pricing compared to the flat pricing provides a reduction in the billing amount of 49 customers and an increase in the billing amount for 74 customers. The average billing decrease over this six-month period is $539 while the average billing increase is $543. (Response to Request for Production Documents No. 2, First Production Request of Oregon Industrial Customers of Idaho Power.)

The Company goes on to conclude,

> The results of the six-month comparison from June 1 through November 30, as well as the results for the January billing period, indicate that the TOU rates have <u>had a negligible effect on the billings for Schedule 19 customers in Idaho compared to the flat rates. Idaho Power believes this effect is due to the general load profile of Schedule 19 customers, who tend to be high load factor, consistent use customers.</u> (Response to Request for Production Documents No. 2, First Production Request of Oregon Industrial Customers of Idaho Power. Emphasis provided.)

The purpose of time-of-use rates is to cause customers to curtail power consumption during the relatively expensive on-peak periods. The results in Idaho clearly show that the flat load industrial customers that make up the class have not changed their power consumption patterns. Idaho Power's own response to the OICIP discovery provides sufficient justification to not implement time of use rates because "Schedule 19 customers . . . tend to be high load factor, consistent use customers."

Q. Do you believe Oregon Schedule 19 customers will react in the same manner as their Idaho counterparts?

A. Data provided by Idaho Power indicates that would be the case. For the years 2002 and 2003 the Company provided billing comparisons between flat and TOU rates for its eight Oregon Schedule 19 customers. The results indicated even less variation than was found in Idaho. As indicated in Exhibit OICIP No. 4, the percentage difference ranged between -0.21% and 0.16%. Idaho Power concluded, ". . .the expected impact of TOU rates for the Company's Oregon Schedule 19 customers mirrors the impact experienced in the Company's Idaho service territory." (Response to Request for Production Documents No. 2, First Production Request of Oregon Industrial Customers to Idaho Power.)

Q. If the Company expects the results in Oregon to mirror that in Idaho (meaning essentially no change in customer behavior) why do you think it is proposing to make the change?

A. Time-of-use rates can be an effective tool in dealing with a utility with peak power constraints. However it is only effective when customers respond to price signals. My guess is that the Company is recommending mandatory TOU rate for Schedule 19 customers because they are the only class with meters that allow its implementation. While TOU rates may be a reasonable tool to change the load profile of the Company, and thus more efficiently use its generating resources, their program is focused on the wrong class. TOU rates may well be effective for the residential class and possibly, to a lesser extent, for the commercial classes. The Company data has clearly shown that TOU rates are ineffective for its large industrial customers. The end result is the introduction of unnecessary bill complexity for a class that will not (and in many cases cannot) respond. Simply put, TOU rates will have essentially no beneficial effect on the Company's load profile. We recommend the Commission reject the mandatory TOU rates for Schedule 19 customers.

Power Supply Costs

Q. The Company claims $47,688,100 in power supply costs in the test year for this docket. Could you briefly describe how they arrived at that value?

A. The Company develops a 76-year average of water conditions that represent their current generation resource mix and system loads. They model individual water conditions each year from 1928 through 2003. For example in 1928 Boardman output is shown to be

417,899.7 MWh, even though the plant did not come on line until 1980. (Exhibit 13, G. Said, Page 2 of 77.) Each of the individual water years is then averaged to develop the power supply costs presented here in docket UE-167. This approach allows Idaho Power to calculate the average generation, and average purchase and sales of electricity over a variety of water conditions. The costs of power that lead to the $47.7 million in power supply costs are developed from plant operating data and using the AURORA model to estimate the market electric prices.

Q. Could you briefly describe the AURORA model?

A. According to EPIS, Inc., the developers of the model, AURORA is an electric price forecasting model of the competitive electric-energy marketplace. The model forecasts forward electric energy prices, the market value of electric generating units, the market value of contracts and portfolios, and analyzes the effect of market uncertainty on forward prices. The model is detailed and complex and models a power system hourly over a given period of time. The model predicts hourly, daily, monthly, and annual prices. The model links a utilities system, like Idaho Power's, to electric power areas or hubs in the west and determines transmission availability and constraints. Therefore the model calculates costs and revenues from off system marketing for a utility based on the resources, loads, costs, etc. in the region. The model simulates a utility's dispatch hourly based on the value of its own resources and the availability and demands in all the hub areas. Therefore, the model requires hundreds of input values that potentially impact the value of power and hence a utility's power supply costs.

Q. Is the AURORA model available to interveners for rate case analysis?

A. The AURORA model is proprietary and available only to interveners who are willing purchase the model. Depending on the option selected the purchase price for the model is $50,000 for a single-user license and $100,000 for access for all employees of a firm. This cost is well beyond the resources of most intervener groups, especially for a small jurisdiction such as Idaho Power's Oregon service territory.

Q. Was the AURORA model used in Idaho Power's Idaho rate case?

A. Yes. The Idaho Staff examined the model and found the power supply expenses proposed by Idaho Power were, "reasonable and are probably low." (Direct Testimony of Rick Sterling, IPC-E-03-13, Feb. 2, 2004, p. 6) Staff went on to recommend that the Company and Staff monitor the actual power supply costs in the coming few years to check the accuracy of the Company's use of the AURORA model.

Q. Have you examined the AURORA model used by Idaho Power's Idaho in this rate case?

A. Because the model is proprietary I have not been able to look inside the model at its algorithms and input values and hence examine the reasonableness of its assumptions. However it is possible to examine the modeled results for 2003 and compare them to actual system values for 2003. In addition, the Company has responded to both our and the Oregon Staff's questions about the AURORA model.

Q. What did you find in comparison of the year 2003 and actual Idaho Power output?

A. At the outset I would like to caution that when "back casting" any model results one must be careful. No model is perfect. In addition, there are many factors that can influence reality beyond those just captured in a model. However, it is a useful exercise if only on an order of magnitude sense. That is, if modeled and actual values are reasonably close, it gives validity to the model and the inputs used to drive the model. However, if the results deviate significantly from reality, then the usefulness of the model can be questioned.

For comparative purposes I used the Company's Exhibit 13 results of 2003 (page 77 of 77) and compared them to what the Company filed in its FERC Form 1 for 2003. As shown in Exhibit OICIP No. 5, the energy output of the Company's resources between modeled results for 2003 and those reported in Form 1 were only 5% different (13.7

million MWh compared to 13.1 million MWh). The only Company resource that varied significantly was Danskin which the modeled estimate was 388.6 MWh compared to 41,793.0 MWh found in Form 1. (I discuss this further later in my testimony).

However the purchase and sales of power varied by a wide margin between those modeled and those reported in Form 1. The Company presents purchased power excluding cogeneration and small power production (CSPP) in Exhibit 13. FERC Form 1 includes these CSPP purchases along with other purchased power. For comparative purposes I have used the Form 1 for these purchases and added them to purchase power in 2003 found in Exhibit 13. The modeled purchased power – including CSPP – is 1.27 million MWh compared to 3.36 million MWh for a difference of 2.09 million MWh. There was also a significant difference found for surplus sales with modeled showing 1.04 million MWh compared to 1.83 million MWh for difference of 786,492 MWh. There was also a substantial difference for the net of purchases minus sales, Exhibit 13 values for 2003 are 230,674 MWh while Form 1 is 1.53 million MWh. Values this divergent are troubling and call into question the validity of the model runs. In addition, because both purchases and sales are greater than those modeled, the assumed prices can make a significant impact on calculated power supply costs.

Q. You pointed out above that Danskin's output was significantly more than modeled. Do you have an explanation for this?

A. The Staff asked Idaho Power if it believed the modeled results that Danskin would operate on average only 9 hours per year. The Company replied:

> While Exhibit 13 indicates a modeled range of Danskin operations, from approximately 1 hour under a 1995 water condition to approximately 32 hours of operation under a 1960 water condition, Idaho Power does not believe that these modeled results reflect the full range of Danskin's anticipated operation under actual conditions. (Idaho Power's Response to Request Staff 227, UE-167.)

Apparently the reason for the Company not believing the modeled results for Danskin is due,

> . . .(1) to the fact that modeled generation at the plant reflects test year loads, not actual loads, and (2) the model, in Idaho Power's opinion overstated the availability of transmission for the importation of power into Idaho Power's service territory from the west. Idaho Power believes Danskin will operate at higher capacity factors than the model produces and that, consequently, the modeled net power supply costs are understated. Idaho Power has, since the summer of 2003, when the net power supply cost runs were completed, refined and enhanced the modeling within AURORA of transmission interconnections between our service territory for both the east and the west. (Idaho Power's Response to Request Staff 85, UE-167.)

Because the AURORA model results rely on the interchange of power between hubs throughout the west a modeling error based on transmission interconnections can have a impact on not only on the Company's peaking plant but also on the amount and value of the purchase and sale of power. The power supply costs for Danskin may be understated; the impact however on the purchase and sale of power is unknown due to the modeling error.

Q. Idaho Power indicated that they have made changes to the model. Do you know what the impact of these changes are and how they may impact the power supply costs filed by the Company in the docket?

A. In response to a discovery request, the Company indicated that it has also made other refinements to the model, however those results are not available for the Commission's consideration in this docket. Since the filing in this docket Idaho Power states:

> Additional refinements or enhancements that have been made by the Company include: a change in the modeling of the Company's hydro generating facilities to improve hourly shaping of generation; the incorporation of a monthly plant capacity shape at Danskin; and an improvement in the modeling of Idaho Power Company hourly load shape, made possible by the enhancement associated with the improved transmission interconnections. These refinements or enhancements have been unitized in a single condition analyses such as those conducted in IRP

analysis, but have not been used for multiple year normalization applications at this time. (Idaho Power's Response to Oregon Industrial Customers No. 3.)

Q. You have demonstrated how the AURORA model used to determine revenue requirement in this docket is flawed. What recommendations do you have?

A. This problem leaves the Commission in a dilemma. First, we do not support using AURORA for the calculation of power supply costs. The AURORA model is a "black box" model that IPCo is now using for support of a full range of its regulatory filings. These include the establishing of PURPA rates, the Company's IRP proposals, and power supply costs for its Idaho PCA filings, etc. The model is expensive and very complex. This leaves interveners without the ability to confirm the validity of the model's many assumptions and equations. If the Company is going to use the model for regulatory purposes, it should be required to provide interveners with access to the model and to justify – in understandable form – its many inputs and the impact they have on model outputs. If the Company is unable or unwilling to do this, then the use of the model for regulatory purposes should be disallowed.

Second, an essential part of any rate case are the net power supply costs of the Company. One alternative would be to use a proxy for purchase and sale prices. In informal discussions with the Oregon Staff this is apparently the path they have chosen. To my level of understanding their approach appears reasonable given the predicament created by a flawed AURORA model being used by Idaho Power in the case.

Power Quality

Q. Keith Kolar of Idaho Power discusses outages in the Oregon service territory in his Direct Testimony. He states in 2003 there were 584 sustained (more than five minutes) interruptions, 893 momentary events, and 103,506 customer-hours out. How do these outages effect Schedule 19 costumers?

A. Schedule 19's largest customer, Heinz, estimates outage costs to that Company alone average $728,000 per year. This estimate is based on outages that bring down a production line. Some outages bring down one line and other times the entire factory goes down. A production line cannot be restarted at the flip a switch. It takes time to get to a point were a line can be restarted. This means lost production, worker productivity and discarded product. Heinz records indicate the lost production time due to electrical outages at the facility over the past five years total nearly 16,000 minutes.

Q. Have you discussed this issue with your clients?

A. Yes. The industrial customers in Ontario are very concerned about the poor power quality they are receiving. There is great concern that Idaho Power's requested rate increase is not going to solve that problem. It 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 resolve these power quality issues.

Q. Do you have any comments on the use of conservation funds paid to Idaho Power by the industrial class?

A. Yes. The industrial customers in Idaho Power's service territory should be able to self-direct their conservation dollars for conservation projects located at their sites. I understand that PacifiCorp and PGE both currently permit such self-direction, so this recommendation would allow Idaho Power's customers to enjoy the same benefits.

Q. Does this conclude your testimony on March 15, 2005

A. Yes.

DON C. READING

PRESENT POSITION

Consulting Economist with Ben Johnson Associates, Inc.

EDUCATION

B.S., Economics – Utah State University
M.S., Economics – Oregon State University
Ph.D., Economics – Utah State University

PROFESSIONAL AND BUSINESS HISTORY

Idaho Public Utilities Commission:
1981 – 1986 Economist/Director of Policy and Administration

Teaching:

1980 –1981	Associate Professor, University of Hawaii-Hilo
1970-1980	Associate and Assistant Professor, Idaho State University
1968-1970	Assistant Professor, Middle Tennessee State Universtiy

Dr. Reading provides expert testimony concerning economic and regulatory issues. He has testified on more that 25 occasions before utility commissions in Alaska, California, Colorado, the District of Columbia, Idaho, Nevada, Texas, Utah and Washington.

His areas of expertise include demand forecasting, long-range planning, price elasticity, marginal pricing, production-simulation modeling, and econometric modeling. He has also provided expert testimony in cases concerning loss of income resulting from wrongful death, injury, or employment discrimination.

Dr. Reading has more that 30 years experience in the field of economics. He has participated in the development of indices reflecting economic trends, GNP growth rates, foreign exchange markets, the money supply, stock market levels, and inflation. He has analyzed such public policy issues as the minimum wage, federal spending and taxation, and import export balances. Dr. Reading is one of four economists providing yearly forecasts of statewide personal income to the State of Idaho for purposes of establishing state personal income tax rates.

Dr. Reading's areas of expertise in the field of energy include demand forecasting, long-range planning, price elasticity, marginal and average cost pricing, production-simulation modeling, and econometric modeling. Among his recent cases was an electric rate design analysis for the Industrial Customers of Idaho Power.

While at Idaho State University, Dr. Reading performed demographic studies using a cohort/survival model and several economic impact studies using input/output analysis.

Among Dr. Reading's current projects are a FERC hydropower re-licensing study (for the Skokomish Indian Tribe) and an analysis of Northern States Power's North Dakota rate design proposal affecting large industrial customers. Dr. Reading has also recently completed an analysis for the Idaho Governor's Office of the impact on the Northwest Power Grid of various plans to increase salmon runs in the Columbia River Basin.

PUBLICATIONS

The Economic Impact of Steelhead Fishing and the Return of Salmon Fishing in Idaho, Idaho Fish and Wildlife Foundation, September, 1977.

Cost Savings from Nuclear Regulatory Reform, Southern Economic Journal, March, 1997, with R. Canterbery and B. Johnson.

A Visitor Analysis for a Birds of Prey Public Attraction, Peregrine Fund, Inc., Nov. 1988.

Investigation of a Capitalization Rate for Idaho Hydroelectric Projects, Idaho State Tax Commission, June, 1988.

"Post PURPA Views," Proceedings of the NARUC Biennial Regulatory Conference, 1983.

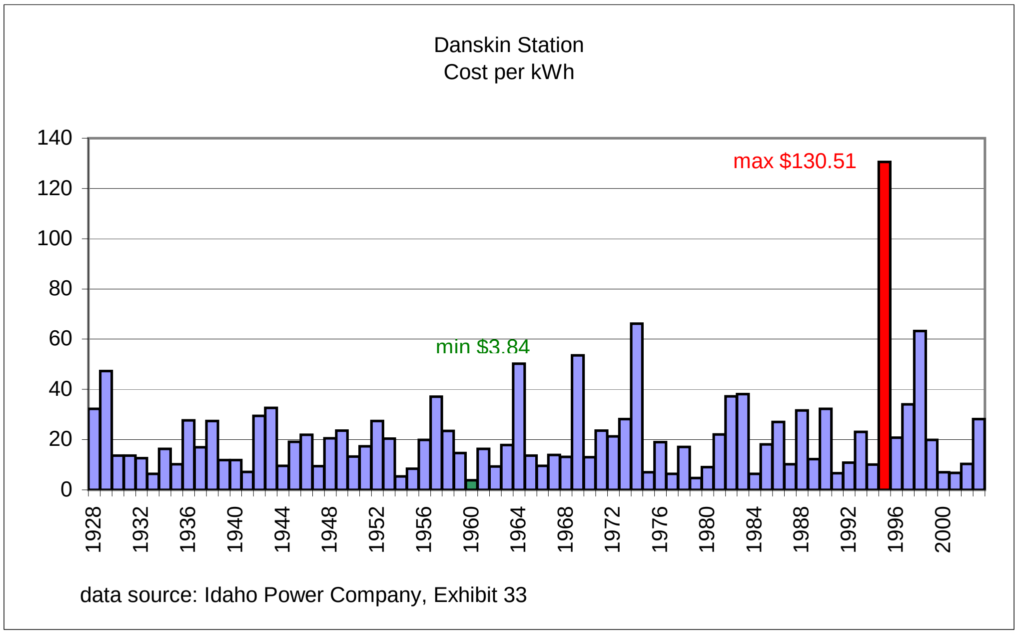
An Input-Output Analysis of the Impact from Proposed Mining in the Challis Area, Public Policy Research Center, Idaho State University, Feb. 1980, with R. Davis.

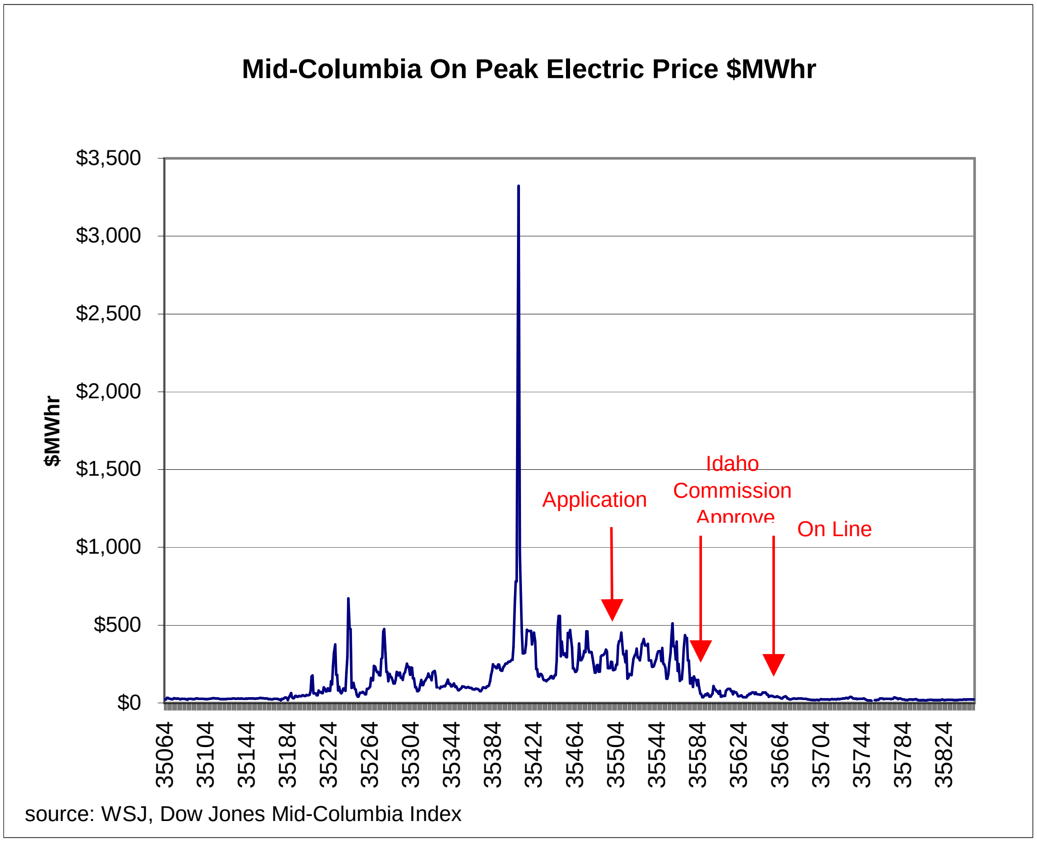
Phosphate and Southeast: A Socio Economic Analysis, Government Research Institute of Idaho State University and the Southeast Idaho Council of Governments, August 1975, with J. Eyre et. al.

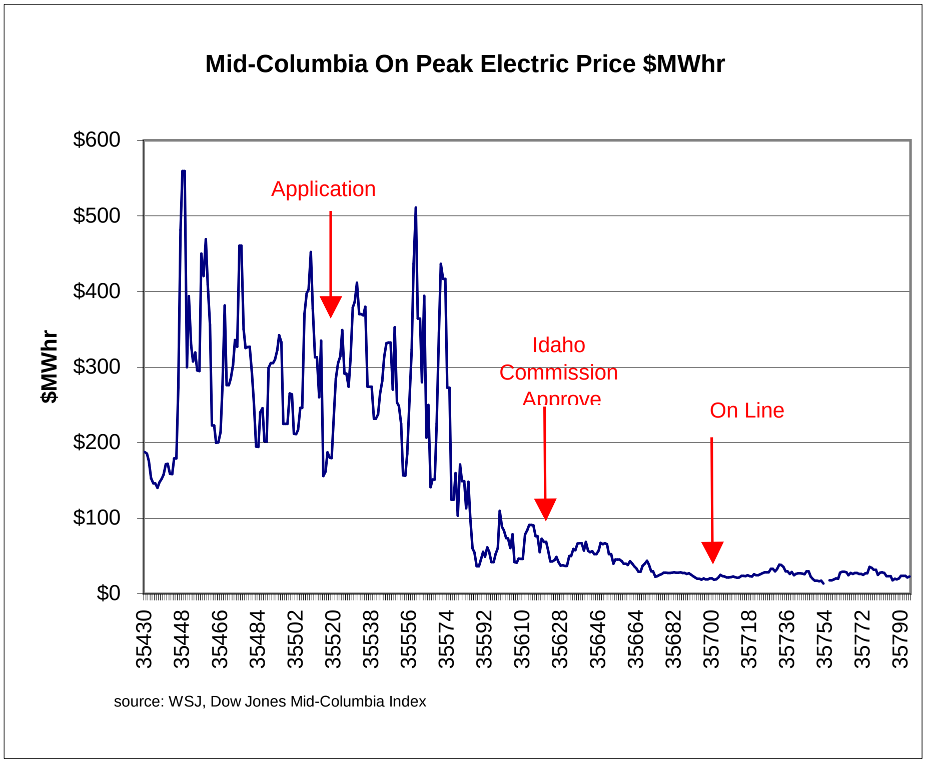
Estimating General Fund Revenues of the State of Idaho, Center for Business and Economic Research, Boise State University, June 1975, with S. Ghazanfar and D. Holley.

"A Note on the Distribution of Federal Expenditures: An interstate Comparison, 1933-1939 and 1961-1965," The American Economist, Vol. XVII, No. 2 (Fall 1974), pp. 125 – 128.

New Deal Activity and the States, 1933-1939, Journal of Economic History, Vol. XXXIII (December 1973), pp. 792 - 810


Danskin Station
Cost per kWh
140
120
100
80
60
40
20
0
max $130.51
min $3.84
1928
1932
1936
1940
1944
1948
1952
1956
1960
1964
1968
1972
1976
1980
1984
1988
1992
1996
2000
data source: Idaho Power Company, Exhibit 33


Mid-Columbia On Peak Electric Price $MWhr
$MWhr
$3,500
$3,000
$2,500
$2,000
$1,500
$1,000
$500
$0
Application
Idaho
Commission
Approve
On Line
35064
35104
35144
35184
35224
35264
35304
35344
35384
35424
35464
35504
35544
35584
35624
35664
35704
35744
35784
35824
source: WSJ, Dow Jones Mid-Columbia Index


Mid-Columbia On Peak Electric Price $MWhr
$MWhr
$600
$500
$400
$300
$200
$100
$0
Application
Idaho
Commission
Approve
On Line
35430
35448
35466
35484
35502
35520
35538
35556
35574
35592
35610
35628
35646
35664
35682
35700
35718
35736
35754
35772
35790
source: WSJ, Dow Jones Mid-Columbia Index

Idaho Power Oregon Schedule 19
Current v. Proposed TOU Rates 2002, 2003

Customer	Dollar Difference TOU/Flat	Percent Difference	Dollar Difference TOU/Flat
1	($247)	-0.18%	($247)
2	($6,209)	-0.21%	($6,209)
3	$71	0.02%	$71
4	($320)	-0.09%	($320)
5	($605)	-0.12%	($605)
6	$99	0.00%	$99
7	$251	0.09%	$251
8	$943	0.13%	$943
	($6,017)		($6,017)

2002

Customer	Difference TOU/Flat	Percent Difference	Difference TOU/Flat
1	$209	0.16%	$209
2	($201)	-0.01%	($201)
3	$187	0.05%	$187
4	($432)	-0.11%	($432)
5	($751)	-0.14%	($751)
6	($13)	0.00%	($13)
7	$238	0.10%	$238
8	$808	0.12%	$808
	$45		$45

Production Request of Oregon Industrial Customers of Idaho Power,
Attachment 3.)

Idaho Power Water Conditions Modeled MWh v. FERC Form 1 MWh: 2003

	Exhibit 13, Page 77 of 77, 2003	FERC Form 1, 2003	Form 1 less Exhibit 13, 2003	Percent Difference
Hydroelectric Generation (mwh)	6,360,522.4	6,149,234.0	(211,288.4)	-3.4%
Bridger				
Energy (mwh)	5,158,995.0	4,820,403.0	(338,592.0)	-7.0%
Boardman				
Energy (mwh)	416,392.2	423,535.0	7,142.8	1.7%
Valmy				
Energy (mwh)	1,788,172.5	1,627,984.0	(160,188.5)	-9.8%
Danskin				
Energy (mwh)	388.6	41,793.0	41,404.4	99.1%
Total Generation	13,724,470.7	13,062,949.0	(661,521.7)	-5.1%
Purchased Power (Excluding CSPP)	619,990.6			
CSPP	654,131.0			
Purchased Power (Including CSPP)	1,274,121.6	3,361,292.0	#########	62.1%
Surplus Sales				
Energy (mwh)	1,043,448.0	1,829,940.0	786,492.0	43.0%
Net Purchases less Sales	230,673.60	1,531,352.00	#########	84.9%
Total MWh	13,955,144.3	16,424,241.0	#########	15.0%

MWh Sold		14,809,971.0