EXHIBIT No. 201

Case No. IPC-E-06-09

D.READING, ICIP

Don C. Reading

Present position Consulting Economist with Ben Johnson Associates, Inc.:

Education B.S., Economics - Utah State University
M.S., Economics - University of Oregon
Ph.D., Economics - Utah State University

Professional and business history

Idaho Public Utilities Commission:
1981-86 Economist/Director of Policy and Administration

Teaching:
1980-81 Associate Professor, University of Hawaii-Hilo
1970-80 Associate and Assistant Professor, Idaho State University
1968-70 Assistant Professor, Middle Tennessee State University

Dr. Reading provides expert testimony concerning economic and regulatory issues. He has testified on more than 25 occasions before utility regulatory 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 than 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, stockmarket 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. He has also provided expert testimony in cases concerning loss of income resulting from wrongful death, injury, or employment discrimination.

Among Dr. Reading's current projects are a FERC hydropower relicensing study (for the Skokomish Indian Tribe) and an analysis of Northern States Power's North Dakota rate design proposals affecting large industrial customers (for J.R. Simplot Company). 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, 1997.

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., November, 1988.

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

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

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

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

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

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

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

EXHIBIT No. 202

Case No. IPC-E-06-09

D.READING, ICIP

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RECEIVED

BY__________

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF IDAHO POWER COMPANY FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE RATE BASING OF THE EVANDER ANDREWS POWER PLANT.	CASE NO. IPC-E-06-09 IDAHO POWER COMPANY'S RESPONSE TO THE FIRST PRODUCTION REQUEST OF THE INDUSTRIAL CUSTOMERS OF IDAHO POWER

COMES NOW, Idaho Power Company ("Idaho Power" or "the Company") and, in response to the First Production Request of the Industrial Customers of Idaho Power to Idaho Power Company dated June 19, 2006, herewith submits the following information:

REQUEST FOR PRODUCTION NO. 1: On page 10 of Greg Said's direct testimony he states:

> *Among the actions recommended by the 2004 IRP was the acquisition of a targeted 88 MW simple-cycle, natural gas-fired combustion turbine. Consistent with the recommendations of the 2004 IRP, the peaking resource RFP requested proposals for an 80 MW— 200 MW turnkey electric generation resources located within the Company's service territory that would meet anticipated peak energy demands. The flexibility in plant capacity permitted under the RFP allowed the developers to respond to the RFP with their most cost-effective proposals.*

Please explain in greater detail how the "flexibility in plant capacity" in the RFP is consistent with the Company's 2004 IRP. Please explain why a simple-cycle resource of nearly twice the size of the 88 MW facility stated in the Near-Term Action Plan is consistent with the IRP.

RESPONSE TO REQUEST NO. 1: The "flexibility in plant capacity" in the RFP is consistent with the Company's 2004 IRP on several counts.

First, one of the primary goals of the 2004 IRP was to ensure that the portfolio of resources selected balanced costs, risks and environmental concerns. Since there was an active secondary market for combustion turbines when the 2004 IRP (and the subsequent peaking RFP) were being prepared, Idaho Power felt that it was appropriate to provide flexibility in the RFP to provide bidders an opportunity to propose a variety of standard turbine sizes capable of meeting the identified peaking need. As a result of the information obtained in the Bennett Mountain RFP, Idaho Power knew that it was possible to acquire larger frame combustion turbines at extremely competitive prices on a $/kW basis. By selecting a larger combustion turbine, Idaho Power has provided additional internal generation resources capable of meeting system load in the event of transmission outages, forced outages of other generation units, extreme weather conditions, or greater than expected load growth. In all of these instances, the risk of curtailment of firm load is reduced by selecting a larger combustion turbine. Given the competitiveness of the pricing in the Bennett Mountain RFP, Idaho Power was able to acquire the incremental 85 MW of capacity (173 MW – 88 MW = 85 MW) at an extremely competitive price – providing additional generation at minimal cost while improving reliability for customers.

Second, the idea of specifying a range of turbine sizes in the peaking resource RFP is discussed on page 75 of the 2004 IRP. Incorporating flexibility in turbine sizing in the RFP is consistent with the discussion on page 75 of the 2004 IRP.

And finally, by incorporating a range of sizes in the RFP and ultimately selecting a 173 MW combustion turbine, Idaho Power has an opportunity to defer additional generation resources in future resource plans. Deferring a large generation resource, even for one year, could result in substantial savings for customers.

The response to this request was prepared by Karl E. Bokenkamp, General Manager Power Supply Planning and Operations, Idaho Power Company, in consultation with Barton L. Kline, Senior Attorney, Idaho Power Company.

EXHIBIT No. 203

Case No. IPC-E-06-09

D.READING, ICIP

REQUEST FOR PRODUCTION NO. 23: On page 15 of Mr. Said's testimony, he states that "[f]orecasted natural gas prices from the 2004 IRP were used in the bid evaluation." At any time during its evaluation of the various responses to Idaho Power's RFP, did Idaho Power use an updated forecast of natural gas prices?

RESPONSE TO REQUEST NO. 23: Idaho Power did not use, nor was it necessary to use, an updated forecast of natural gas prices to evaluate the responses to the RFP. In bid evaluations, it is only necessary that the <u>same</u> gas price forecast be used to calculate estimated variable operating costs for all of the bids to allow for a consistent cost comparison among the bids.

The response to this request was prepared by Randy Henderson, Business Analyst, Idaho Power Company, in consultation with Monica B. Moen, Attorney II, Idaho Power Company.

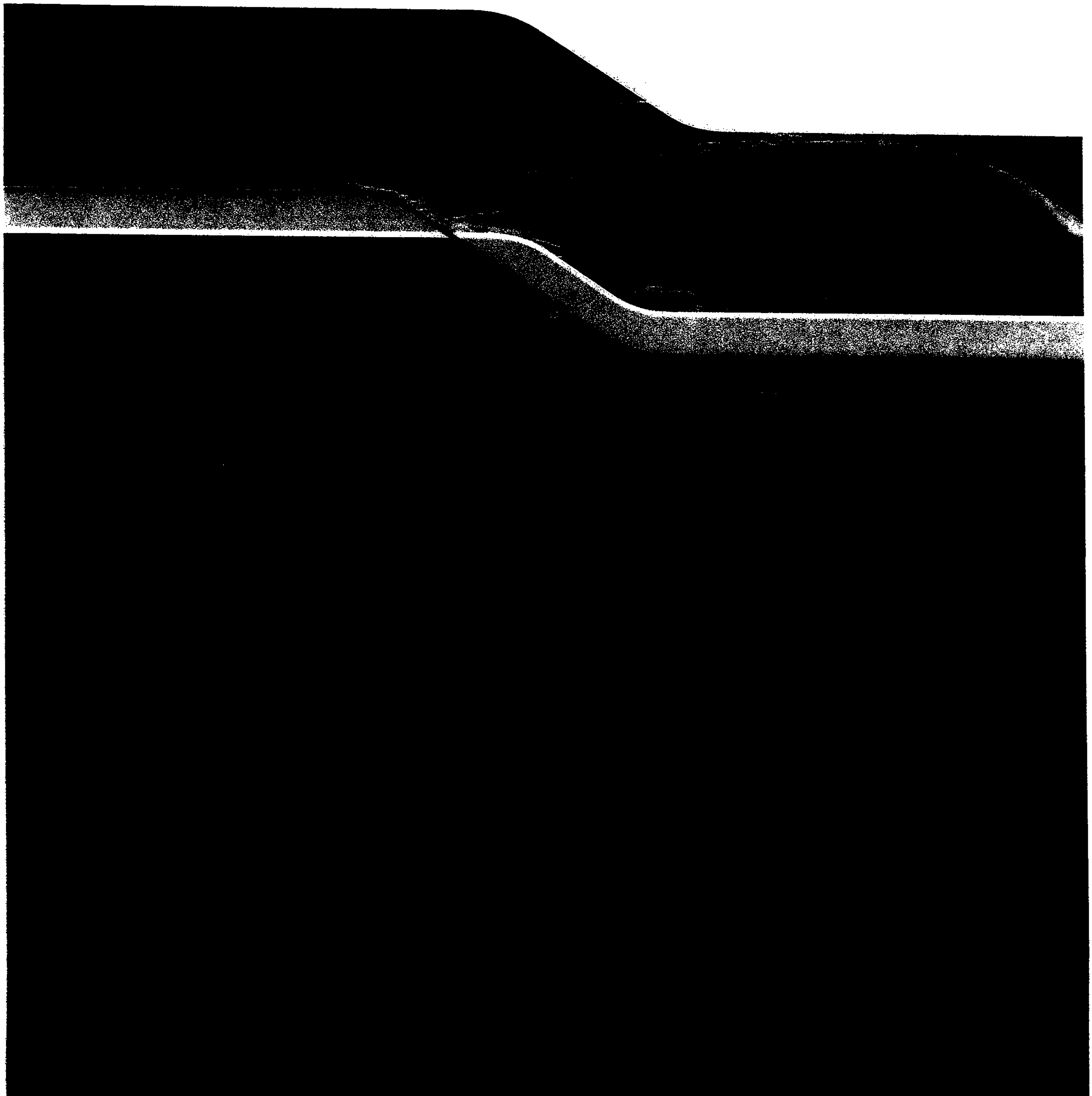
EXHIBIT No. 204

Case No. IPC-E-06-09

D.READING, ICIP

IDAHO POWER
An IDACORP Company

2006 Integrated Resource Plan



2006 Integrated Resource Plan

IDAHO POWER
An IDACORP Company

1. 2006 Integrated Resource Plan Summary

Introduction

The 2006 Integrated Resource Plan (IRP) is Idaho Power Company's eighth resource plan prepared to fulfill the regulatory requirements and guidelines established by the Idaho Public Utilities Commission (IPUC) and the Oregon Public Utility Commission (OPUC).

In developing this plan, Idaho Power worked with the Integrated Resource Plan Advisory Council (IRPAC), comprised of major stakeholders representing the environmental community, major industrial customers, irrigation customers, state legislators, public utility commission representatives, the Governor's office, and others. The IRPAC meetings served as an open forum for discussion related to the development of the IRP, and its members have made significant contributions to this plan. While input from the IRPAC has been considered and incorporated into the 2006 IRP, final decisions on the content of the plan were made by Idaho Power. A list of IRPAC members can be found in *Appendix D–Technical Appendix*. Idaho Power encourages IRPAC members to submit comments expressing their views regarding the 2006 IRP and the planning process.

The 2006 IRP assumes that during the planning period (2006–2025), Idaho Power will continue to be responsible for acquiring resources sufficient to serve all of its retail customers in its mandated Idaho and Oregon service areas and will continue to operate as a vertically-integrated electric utility.

The two primary goals of Idaho Power's 2006 IRP are to:

1. Identify sufficient resources to reliably serve the growing demand for energy within Idaho Power's service area throughout the 20-year planning period; and

2. Ensure the portfolio of selected resources balances costs, risks, and environmental concerns.

In addition, there are several secondary goals:

1. Give equal and balanced treatment to both supply-side resources and demand-side measures;

Highlights

- Idaho Power uses 70th percentile water conditions and 70th percentile average load for energy planning.
- For peak-hour capacity planning, Idaho Power uses 90th percentile water conditions and 95th percentile peak-hour load.
- The 2006 IRP includes 1,300 MW (nameplate) of supply-side resource additions and DSM programs designed to reduce peak load by 187 MW and average load by 90 aMW.
- Idaho Power's average load is expected to increase by 40 aMW (1.9% annually); summertime peak-hour loads are expected to increase by 80 MW (2.1% annually) per year through 2025.
- Idaho Power expects to add 11,000–12,000 retail customers per year through 2025.
- In July 2006, Idaho Power set a new peak-hour load record of 3,084 MW.

2. Involve the public in the planning process in a meaningful way;

3. Explore transmission alternatives; and

4. Investigate and evaluate advanced coal technologies.

The number of households in Idaho Power's service area is expected to increase from around 455,000 in 2005 to over 680,000 by the end of the planning period in 2025. Population growth in southern Idaho is an inescapable fact, and Idaho Power will need to add physical resources to meet the electrical energy demands of its growing customer base.

Idaho Power, with hydroelectric generation as the foundation of its energy production, has an obligation to serve customer loads regardless of the water conditions which may occur. In light of public input and regulatory support of the more conservative planning criteria used in the 2002 IRP, Idaho Power will continue to emphasize a resource plan based upon a worse-than-median level of water. In the 2006 IRP, Idaho Power is again emphasizing 70th percentile water conditions and 70th percentile average load for energy planning, and the 90th percentile water conditions and 95th percentile peak-hour load for capacity planning. A 70th percentile water condition means Idaho Power plans generation based on a level of streamflows that is exceeded in seven out of ten years on average. Conversely, streamflow conditions are expected to be worse than the planning criterion in three out of ten years. This is a more conservative planning criterion than median water planning, but less conservative than critical water planning. Further discussion of Idaho Power's planning criteria can be found in Chapter 4.

Idaho Power extended the planning horizon in the 2006 IRP to 20 years. Recent Idaho Power IRPs utilized a 10-year planning horizon, but with the increased need for baseload resources with long construction lead times along with the need for a 20-year resource plan to support PURPA contract negotiations, Idaho Power and the IRPAC decided to extend the planning horizon of the 2006 IRP to 20 years.

Potential Resource Portfolios

Idaho Power examined 12 resource portfolios and several variations of portfolios in preparing the 2006 IRP. Discussions with the IRPAC led to the selection of four finalist portfolios for additional risk analysis—a portfolio that emphasized thermal resources, a portfolio with a strong commitment to renewable resources, a resource portfolio that emphasized regional transmission, and a modified version of the 2004 IRP preferred portfolio.

Following the risk analysis, a modified version of the 2004 preferred portfolio was selected as the preferred portfolio for the 2006 IRP. The selected portfolio adds supply-side and demand-side resources capable of providing 1,091 MW of energy, 1,250 MW of capacity to meet peak-hour loads, and 285 MW of additional transmission capacity from the Pacific Northwest. The selected portfolio also includes demand-side management (DSM) programs estimated to reduce loads by 90 aMW annually and peak-hour loads by 187 MW.

The preferred portfolio represents resource acquisition targets. It is important to note the actual resource portfolio may differ from the above quantities depending on acquisition or development opportunities, specific responses to Idaho Power's Request for Proposals (RFPs), the business plans of any ownership partners, and the changing needs of Idaho Power's system.

Risk Management

Idaho Power, in conjunction with the IPUC staff and interested customer groups, developed a risk management policy during 2001 to protect against severe movements in Idaho Power's wasted is used to produce additional power beyond that typically produced by a SCCT. New CCCT plants could be built or existing simple-cycle plants could be converted to combined-cycle units.

The CCCT resources that were studied in the 2006 IRP were assumed to be located in southwestern Idaho in close proximity to mainline fuel supply and within 25 miles of Idaho Power's transmission system. The cost estimates and operating parameters for CCCT generation in the 2006 IRP are based on data from the NWPCC's Fifth Power Plan (2005). Potential generation studied in each of the various portfolios ranged from 0 MW up to 250 MW of additional CCCT capacity over the 20-year planning period.

CCCT Advantages

- Proven and reliable technology
- Operational flexibility
- Dispatchable resource
- Greater than 50% reduction in CO_2 emissions per MWh of output compared to conventional pulverized coal technology.

CCCT Disadvantages

- Natural gas price volatility
- Potential fuel supply and transportation issues

Simple-Cycle Combustion Turbines

Several natural gas-fired SCCTs have been brought on-line in the region in recent years primarily in response to the regional energy crisis of 2000–2001 when electricity prices spiraled out of control. High electricity prices combined with persistent drought conditions during the 2000–2001 time period as well as continued summertime peak load growth created interest in generation resources with low capital costs and relatively short construction lead times. Idaho Power currently has approximately 250 MW of SCCT capacity in its existing resource fleet, and plans to have another 170 MW on-line by the summer of 2008. Peak summertime electricity demand continues to grow significantly within Idaho Power's service area, and SCCT generating resources have been constructed to meet peak load during the critical high demand times when the transmission system has reached full import capacity. The plants may also be dispatched for financial reasons during times when regional energy prices are at their highest. Like CCCTs, feasible sites and gas supply currently exist for future SCCT development.

Simple-cycle natural gas turbine technology involves pressurizing air which is then heated by burning gas in fuel combustors. The hot pressurized air is expanded through the blades of the turbine which is connected by a shaft to the electric generator. Designs range from larger industrial machines at 80–200 MW to smaller machines derived from aircraft technology. SCCTs have a lower thermal efficiency than other fossil fuel-based resources and are not typically economical to operate other than to meet peak-hour load requirements.

The SCCT resources that were studied in this plan are assumed to be located in southwestern Idaho in close proximity to mainline fuel supply and within 25 miles of Idaho Power's transmission system. The cost estimates and operating parameters for SCCT generation in the IRP are based on data from the NWPCC's Fifth Power Plan (2005). Potential generation resources studied in each of the various portfolios ranged from 0 MW up to 680 MW of additional SCCT capacity over the 20-year planning period.

SCCT Advantages

- Dispatchable resource
- Proven, reliable resource
- Low capital cost
- Short construction lead times
- Ideal for peaking service

SCCT Disadvantages

- High variable operating cost
- Typically not economical for baseload operation
- Low efficiency
- Natural gas price volatility

Combined Heat and Power

Opportunities exist in the region to take advantage of excess heat energy created by certain industrial processes. Partnerships could be developed with some industrial customers and CHP generating units could be installed at facilities with existing steam requirements. A common type of CHP system uses a combustion turbine generator to produce electrical power and also produces steam by installing a heat recovery steam generator in the exhaust path of the combustion turbine. The electrical power from the combustion turbine is delivered to the distribution and transmission system, and the steam is used to meet the industrial facility requirements. The steam could either be sold to the industrial facility or the industrial facility could own the steam-generating portion of the plant.

The cost estimates and operating parameters for CHP generation in the 2006 IRP are based on data gathered in Idaho Power's 2004 IRP, with escalation applied at 3 percent. Estimates are based only on the electrical generation portion of the facility. The actual plant costs are highly dependent on the specific plant configuration, as well as the specific contract and ownership agreement. The CHP opportunities studied in the 2006 IRP are assumed to be located in southern Idaho in close proximity to Idaho Power's transmission system. The potential generation studied in each of the various portfolios ranged from 0 MW up to 200 MW of additional CHP capacity over the 20-year planning period.

CHP Advantages

- Dual use of fuel
- High fuel utilization efficiency
- Facilities are often located in close proximity to the load center

CHP Disadvantages

- Natural gas price volatility
- Shared ownership and associated operational concerns

Biomass

Biomass fuels like wood residues, organic components of municipal solid waste, animal manure, and wastewater treatment plant gas can be used to power a steam turbine or reciprocating engine to produce electricity. Most of the biomass-generating resources in the region are small-scale local co-generating operations. The use of biomass fuels has not proven to be economic for large-scale commercial power production. Available fuel supply can vary as production from the industry fluctuates. The biomass fuel sources assumed in the resource cost analysis for the plan are wood by products from the forest and wood products industry. The cost estimates and operating

For the mid-term, Idaho Power expects to add approximately 150 MW of additional wind generation in 2012, followed by approximately 250 MW of pulverized coal-fired generation in 2013. Idaho Power will need to sign and commit to agreements for construction in 2007 in order to meet the projected 2013 on-line date.

In the longer term, the 2006 IRP includes approximately 250 MW of IGCC in 2017, approximately 100 MW of additional CHP at customers' facilities in 2020, approximately 100 MW of additional geothermal generation in 2021–2022, and approximately 250 MW of advanced nuclear generation at the INL in 2023. Idaho Power anticipates acquiring the energy from the advanced nuclear project through a PPA.

Idaho Power prefers that its future coal-fired facilities be composed of smaller individual units or percentage ownership shares of larger units. A smaller unit reduces the amount of generation at risk due to equipment failure, and a larger unit will provide economy of scale cost savings not possible with smaller units. Spreading the generation over more units in different locations provides for greater operational flexibility and reliability. In addition, the construction timing of more and smaller generating units may better coincide with customer load growth in Idaho Power's service area.

Idaho Power will continue to explore the idea of seasonal ownership, or exchange arrangements that simulate seasonal ownership, with interested parties.

Idaho Power faces uncertainty regarding the future addition of PURPA generation. If the quantity of Idaho Power's PURPA generation significantly changes from the 172 aMW assumed in the 2006 IRP, the Near-Term and Ten-Year action plans may need to be revised.

Demand-Side Resources

The 2006 IRP adds several new programs as well as expanding existing programs. Overall, the preferred portfolio adds a set of demand-side programs that are forecast to reduce average loads by 90 aMW on an annual basis and reduce the summertime peak-hour load by 187 MW. Since summertime loads drive Idaho Power's capacity needs, the DSM programs are designed to provide significant load reductions during summertime peak-hour loads.

Renewable Energy

In 2005, Idaho Power hydroelectric generation supplied 36 percent of the MWh used by Idaho Power customers under low water conditions. By 2025, under normal water conditions, hydroelectric generation will continue to supply about 33 percent of the MWh used by Idaho Power customers.

Wind, geothermal, and other non-hydro renewable resources supplied a negligible amount of energy used by Idaho Power customers in 2005. Other than power purchased from several small PURPA projects and green tags acquired to support the Green Energy Program, Idaho Power had no major non-hydro renewable energy purchases in 2005. However, in future years Idaho Power anticipates acquiring a greater amount of non-hydro renewable energy given the number of PURPA resources either under contract or in contract negotiations. Although Idaho Power is required to purchase the output from qualified PURPA projects, at present it does not own the green tags associated with PURPA generation. Without the green tags, Idaho Power cannot claim the environmental attributes associated with the PURPA generation. Furthermore, without obtaining the green tags, Idaho Power may not be able to count the PURPA generation toward meeting a future RPS.

The preferred portfolio includes approximately 250 MW of wind generation and 150 MW of geothermal generation by 2025. These additions, based on nameplate ratings, result in non-hydro renewable resources equaling 8.0 percent of Idaho Power's total generation resources by 2025. If the nameplate capacity of existing small hydro, wind, and geothermal PURPA contracts are considered, renewable resources would account for 9.8 percent of Idaho Power's current generation portfolio. If the same existing PURPA contracts are included with the 400 MW identified in the preferred portfolio, renewable resources would account for 14.1 percent of Idaho Power's total generation portfolio by 2025. This figure likely underestimates the percentage of renewable resources Idaho Power will have in 2025 because new renewable PURPA resources have not been estimated or included in the calculation.

Peaking Resources

The 2006 IRP adds 1,250 MW of capacity additions to the resource portfolio. Idaho Power will add wind, geothermal, and thermal resources in the near and mid-term. In addition to the capacity contemplated in the 2006 IRP, Idaho Power has committed to adding the 170 MW Danskin combustion turbine, which is scheduled to be on-line in 2008, and the 49 MW Shoshone Falls upgrade, which is scheduled to be on-line in 2010. With the addition of the 170 MW Danskin combustion turbine in 2008, Idaho Power will have 424 MW of natural gas-fired peaking generation.

The primary purpose of the combustion turbines is to provide the generation capacity necessary to meet peak-hour loads. However, Idaho Power has the option to operate the combustion turbines to meet monthly energy requirements within the emission limits of the facility permits. Given current and forecasted natural gas prices, purchasing energy from the regional markets, up to the limits of the transmission system, will most likely be more economical than operating the combustion turbines as an energy resource. However, Idaho Power anticipates operating the combustion turbines whenever customer load exceeds the generation capacity of its other generation units and the import capacity of the transmission system.

Market Purchases

Under low water conditions in 2005, Idaho Power purchased 22 percent of the MWh used by its customers from the regional energy markets. By 2025, under normal water and renewable conditions, purchased power is expected to supply only 4 percent of the energy used by Idaho Power's customers. Summertime on-peak capacity purchases will still be necessary and Idaho Power expects to continue to use its full share of the transmission system to access regional power markets.

Idaho Power's regional trading partners sometimes offer term market purchases and exchanges. Idaho Power will continue to evaluate the regional market purchases and exchanges on a case-by-case basis.

Transmission Resources

The 2006 IRP includes 285 MW of transmission upgrades, significantly improving Idaho Power's ability to import power from the Mid-Columbia market in the Pacific Northwest. Construction of a single conductor, 230 kV, single-circuit line from McNary to Brownlee, Brownlee to Ontario, and Ontario to the Garnet and Locust substations will add approximately 225 MW of additional import capacity. The other upgrade is to reconductor the 230 kV single-circuit line from Lolo to Oxbow, which will add approximately 60 MW of additional import capacity.

The planned supply-side resource additions will require significant upgrades to the backbone transmission system. Idaho Power has already begun the process to upgrade the Borah–West transmission path as detailed in the 2004 IRP. A considerable amount of renewable generation is expected to be located in eastern Idaho which will require an improved Borah–West transmission path to reach the Treasure Valley load center. The Borah–West transmission path upgrade is scheduled to be completed in May 2007, which will provide a 250 MW increase in east to west transfer capability on the Borah–West path. The Borah–West upgrades are necessary to serve Idaho Power's native load—either through resources identified in the 2006 IRP or through additional imports from the east side. Additional upgrades to the Borah–West and Midpoint–West transmission paths will be necessary if more resources are added in eastern Idaho or Wyoming as identified in the 2006 Integrated Resource Plan.

The coal-fired resource scheduled for 2013 will also require significant transmission upgrades to deliver the energy to the Treasure Valley.

Because the specific site of the coal-fired resource has not been identified, the required transmission upgrades are unknown and a generic cost estimate was used in the analysis.

Demand-Side Management Programs

Idaho Power anticipates increasing the emphasis on demand-side programs during the planning period. By 2025, Idaho Power anticipates that the energy efficiency programs initiated in the 2004 IRP, combined with the programs identified in the 2006 IRP, will reduce energy demand by 108 aMW. Figure 7-1 shows Idaho Power's estimated energy sources in 2007 and 2025, assuming normal water and weather conditions.

Figure 7-1. Idaho Power Energy Sources in 2007 and 2025

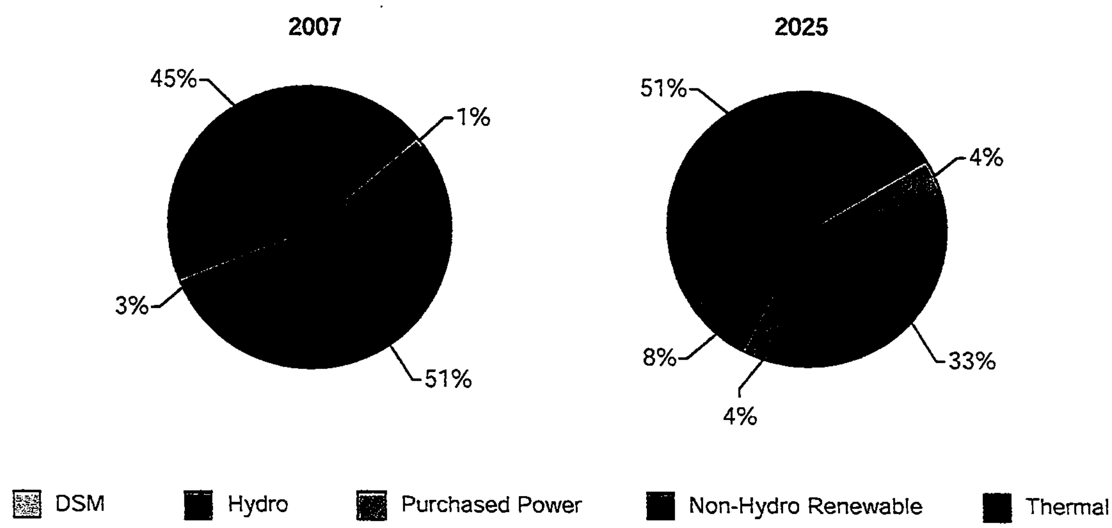


EXHIBIT No. 205

Case No. IPC-E-06-09

D.READING, ICIP

TABLE OF CONTENTS

The CCCT resources that were studied in the 2006 IRP were assumed to be located in southwestern Idaho in close proximity to mainline fuel supply and within 25 miles of Idaho Power's transmission system. The cost estimates and operating parameters for CCCT generation in the IRP are based on data from the Northwest Power and Conservation Council's Fifth Power Plan (2005). Potential generation that was studied in each of the various portfolios ranged from 0 MW up to 250 MW of additional CCCT capacity over the 20-year planning period.

CCCT Advantages

- Proven and reliable technology
- Operational flexibility
- Dispatchable resource
- Less greenhouse emissions than coal

CCCT Disadvantages

- Natural gas price volatility
- Potential fuel supply issues

Simple Cycle Combustion Turbines (SSCT)

Several natural gas-fired simple cycle combustion turbines (SSCTs) have been brought online in the region in recent years primarily in response to the regional energy crisis of 2000–2001 when electricity prices spiraled out of control. High electricity prices combined with persistent drought conditions during the 2000–2001 time period as well as continued summertime peak load growth created interest in generation resources with low capital costs and relatively short construction lead times. Idaho Power currently has approximately 250 MW of SSCT capacity in its existing resource fleet, and plans to have another 160 MW online by the summer of 2008. Peak summertime electricity demand continues to grow significantly within Idaho Power's service area, and SSCT generating resources have been constructed to meet peak load during the critical high demand times when the transmission system has reached full import capacity. The plants may also be dispatched for financial reasons during times when regional energy prices are at their highest. Like CCCTs, feasible sites and gas supply currently exist for future SSCT development. However, the forecasted trend of high natural gas prices has reduced interest in future SSCT generation plants.

Simple cycle natural gas turbine technology involves pressurizing air which is then heated by burning gas in fuel combustors. The hot pressurized air is expanded through the blades of the turbine which is connected by a shaft to the electric generator. Designs range from larger industrial machines at 80–200 MW to smaller machines derived from aircraft technology. SSCTs have a lower thermal efficiency than other fossil fuel based resources and are not typically economical to operate other than to meet peak load requirements.

The SSCT resources that were studied in this plan are assumed to be located in southwestern Idaho in close proximity to mainline fuel supply and within 25 miles of Idaho Power's transmission system. The cost estimates and operating parameters for SSCT generation in the IRP are based on data from the Northwest Power and Conservation Council's Fifth Power Plan (2005). Potential generation resources studied in each of the various portfolios ranged from 0 MW up to 680 MW of additional SSCT capacity over the 20-year planning period.

SSCT Advantages

- Dispatchable resource
- Proven, reliable resource
- Low capital cost

- Short construction lead times
- Ideal for peaking service

SSCT Disadvantages

- Very high variable operating cost so not economic for baseload operations
- Low efficiency
- Natural gas price volatility

Combined Heat and Power (CHP)

Opportunities exist in the region to take advantage of excess heat energy that is created by certain industrial processes. Partnerships could be developed with some industrial customers and combined heat and power (CHP) generating units could be installed at facilities that have existing steam requirements. A common type of CHP system uses a combustion turbine generator to produce electrical power and also produces steam by installing a heat recovery steam generator in the exhaust path of the combustion turbine. The electrical power from the combustion turbine is delivered to the distribution and transmission system and the steam is used to meet the industrial facility requirements. The steam could either be sold to the industrial facility or the industrial facility could own the steam generating portion of the plant.

The cost estimates and operating parameters for CHP generation in the IRP are based on data gathered in the Idaho Power 2004 IRP, with escalation applied at 3 percent. Estimates are based only on the electrical generation portion of the facility. The actual plant costs are highly dependent on the specific plant configuration as well as the specific contract and ownership agreement. The CHP opportunities that were studied in the 2006 IRP are assumed to be located in southern Idaho in close proximity to Idaho Power's transmission system. The potential generation that was studied in each of the various portfolios ranged from 0 MW up to 200 MW of additional CHP capacity over the 20-year planning period.

CHP Advantages

- Dual use of fuel
- Facilities are often located in close proximity to the load center

CHP Disadvantages

- Natural gas price volatility
- Shared ownership and associated operational concerns

Biomass

Biomass fuels like wood residues, organic component of municipal solid waste, animal manure, and wastewater treatment plant gas can be used to power a steam turbine generator and produce electricity. Most of the generating resources that use biomass in the region are very small scale local co-generating operations. The use of biomass fuels has not proven to be economic for large scale commercial power production. Available fuel supply can vary as production from the industry fluctuates. The biomass fuel sources assumed in the resource cost analysis for the plan are wood byproducts from the forest and wood products industry. The cost estimates and operating parameters for biomass-fueled generation in the plan are based on data from the Northwest Power and Conservation Council's Fifth Power Plan (2005). No biomass-fueled generation resources were included in the portfolios analyzed for the 2006 Integrated Resource Plan.

Solar Energy and Photovoltaics

The conversion of solar radiation to electricity is typically achieved by capturing heat to power a conventional generating cycle like a steam

Idaho Power prefers that its future coal-fired facilities be composed of smaller individual units, or percentage ownership shares of larger units. While a smaller unit reduces the amount of generation at risk due to equipment failure, Idaho Power also anticipates a smaller ownership share of a larger unit will provide economy of scale cost savings possible with larger units. Spreading the generation over more units in different locations provides for greater operational flexibility and reliability. In addition, the construction timing of more and smaller generating units may better coincide with customer load growth in Idaho Power's service area.

Idaho Power will continue to explore the idea of seasonal-ownership, or exchange arrangements that simulate seasonal ownership, with interested parties.

Idaho Power faces uncertainty regarding the future addition of PURPA generation. If the quantity of Idaho Power PURPA generation significantly changes from the 172 aMW assumed in the 2006 IRP, the Near-Term and Ten-Year action plans may need to be revised.

Demand Side Resources

The 2006 IRP adds several new programs as well as implementing expansions of existing programs. Overall, the preferred portfolio adds a set of demand-side programs that are expected to reduce loads by approximately 90 aMW and reduce the system peak-hour load by approximately 187 MW during the summertime. Since summertime loads drive Idaho Power's capacity needs, the DSM programs are designed to provide significant load reductions during summertime peak-hour loads.

Renewable Energy

In 2005, Idaho Power hydroelectric generation supplied 36 percent of the MWh used by Idaho Power customers under low water conditions. By 2015, under normal water conditions, hydroelectric generation will continue to supply about XX percent of the MWh used by Idaho Power customers.

Wind, geothermal, and other non-hydro renewable resources supplied a negligible amount of energy used by Idaho Power customers in 2005. Other than power purchased from several small PURPA projects and green tags acquired to support the Green Energy Program, Idaho Power had no major non-hydro renewable energy purchases in 2005. However, in future years Idaho Power anticipates acquiring a greater amount of non-hydro renewable energy given the number of renewable PURPA resources which have recently been contracted. Although Idaho Power is required to purchase the output from qualified PURPA projects, at present Idaho Power does not own the renewable energy credits (RECs) or Green Tags associated with PURPA generation.

Idaho Power intends to acquire approximately 250 MW of wind generation and 50 MW of geothermal generation by 2015. By 2015, non-hydro renewable resources will supply XX percent of the MWh used by Idaho Power customers under normal weather and water conditions. However, if Idaho Power acquires the RECs associated with the anticipated generation from non-hydro renewable PURPA resources, the percentage of non-hydro renewable energy will increase to XX percent.

Peaking Resources

The 2006 IRP adds 1,250 MW of generation capacity additions to the resource portfolio. Idaho Power will add wind, geothermal, and thermal resources in the near and mid-term. In addition to the capacity contemplated in the 2006 IRP, Idaho Power has committed to adding the 170 MW Danskin combustion turbine which is scheduled to be online in 2008 and the 64 MW Shoshone Falls upgrade which is scheduled to be online in 2010. With the addition of the 170 MW Danskin combustion turbine in 2008, Idaho Power will have 424 MW of natural gas-fired peaking generation.

The primary purpose of the combustion turbines is to provide the generation capacity necessary to meet peak-hour loads. However, Idaho Power has the option to operate the combustion turbines to meet monthly energy requirements within the emission limits of the facility permits. Given current and forecasted natural gas prices, purchasing energy from the regional markets, up to the limits of the transmission system, will most likely be more economical than operating the combustion turbines as an energy resource. Idaho Power anticipates operating the combustion turbines primarily when customer load exceeds the generation capacity of its other generation units and the import capacity of the transmission system.

Market Purchases

Under low water conditions in 2005, Idaho Power purchased 22 percent of the MWh used by its customers from the regional energy markets. By 2015, under normal water and renewable conditions, purchased power is expected to supply only X percent of the energy used by Idaho Power customers. Summertime on-peak capacity purchases will still be necessary and Idaho Power expects to continue to use its full share of the transmission system to access regional power markets.

Idaho Power's regional trading partners sometimes offer term market purchases and exchanges. Idaho Power will continue to evaluate the regional market purchases and exchanges on a case-by-case basis.

Transmission Resources

The 2006 IRP includes 285 MW of transmission upgrades, significantly improving Idaho Power's ability to import power from the Mid-Columbia market in the Pacific Northwest. Construction of a single conductor, 230 kV, single circuit line from McNary to Brownlee, Brownlee to Ontario, and Ontario to the Garnet and Locust substations will add approximately 225 MW of additional import capacity. The other upgrade is to reconductor the 230 kV single circuit line from Lolo to Oxbow which will add approximately 60 MW of additional import capacity.

The planned supply-side resource additions will require significant upgrades to the backbone transmission system. Idaho Power has already begun the process to upgrade the Borah-West transmission path. A considerable amount of renewable generation is expected to be located in eastern Idaho which will require an improved Borah-West transmission path to reach the Treasure valley load center. Idaho Power intends to increase the capacity of the Borah-West transmission path by 150 MW in 2006 and has also applied to increase the capacity of the Borah-West transmission path by an additional 100 MW in 2008. The Borah-West upgrades are necessary to serve Idaho Power's native load—either through resources identified in the 2006 IRP or through additional imports from the east side. Additional upgrades to the Borah-West and Midpoint-West transmission paths will be necessary if more resources are added in eastern Idaho or Wyoming as identified in the 2006 Integrated Resource Plan.

It is likely that the coal-fired resource scheduled for 2013 will also require significant transmission upgrades. Because the site of the proposed coal-fired resource has not been identified, the required transmission upgrades are unknown and a generic cost estimate was used in the analysis.

Demand-Side Management Programs

Idaho Power anticipates increasing the emphasis on demand-side programs during the planning period. By 2025, Idaho Power anticipates that the energy efficiency programs initiated in the

EXHIBIT No. 206

Case No. IPC-E-06-09

D.READING, ICIP

REQUEST NO. 96: In Request No. 1 of the Commission Staff, Staff requested a copy of load-resource balance data by month for each of the years **2006-2026** for six different assumed water and load conditions, with and without the addition of the proposed Evander Andrews plant. The requested time period was chosen specifically to correspond to the time period covered by the **2006** IRP. 2006 IRP load-resource balance data has been in use by the Company for several months during the preparation of the 2006 IRP; consequently, Staff assumed it could also be used to re-examine the need for the Evander Andrews plant. In the Company's initial response to this request, Idaho Power provided load-resource balance data for the period 2004-2013, apparently from the 2004 IRP.

Please provide a response to this request using load-resource balance data consistent with the data that will be used in the **2006** IRP.

RESPONSE TO REQUEST NO. 96: The requested information is attached hereto as "Response to Request No. 96."

The response to this request was prepared by Phil DeVol, Planning Analyst, Idaho Power Company, in consultation with Monica B. Moen, Attorney II, Idaho Power Company.

IDAHO POWER COMPANY

CASE NO. IPC-E-06-9

FOURTH PRODUCTION REQUEST

OF COMMISSION STAFF

RESPONSE TO

REQUEST NOS. 96 & 99

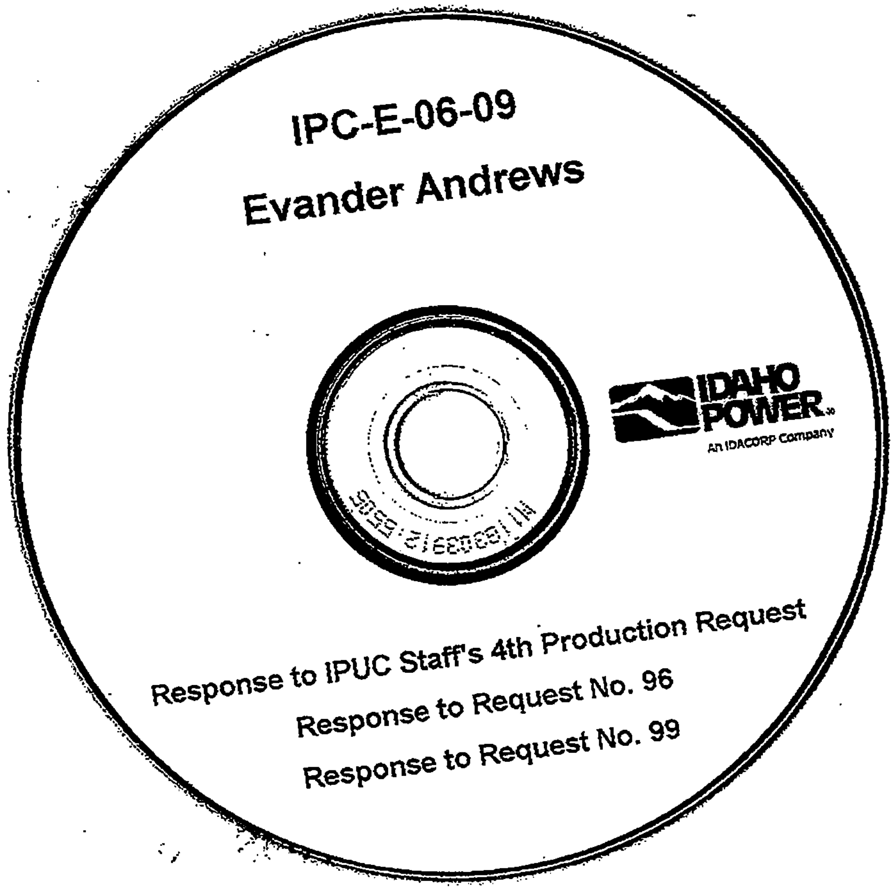

IPC-E-06-09
Evander Andrews
IDAHO POWER
An IDACORP Company
Response to IPUC Staff's 4th Production Request
Response to Request No. 96
Response to Request No. 99

EXHIBIT No. 207

Case No. IPC-E-06-09

D.READING, ICIP

REQUEST NO. 95: A natural gas fired peaking plant was not selected as part of the preferred portfolio chosen in the Draft 2006 IRP. If 2006 IRP assumptions are used and the proposed Evander Andrews plant is assumed to be a resource option instead of part of Idaho Power's existing generation fleet, would the Evander Andrews plant be chosen as part of the preferred portfolio?

RESPONSE TO REQUEST NO. 95: If 2006 IRP assumptions are used and the proposed Evander Andrews plant is assumed to be a resource option instead of part of Idaho Power's existing generation fleet, it is almost certain that the peaking resource Idaho Power is proposing to add to the Evander Andrews would have been selected as a part of the preferred portfolio. With the continued growth in summertime peak-hour loads, Idaho Power needs either generation resources internal to its system or additional firm transmission capacity to markets with availability of firm summertime peak-hour energy.

The 2006 IRP predicts the 2007 summertime peak-hour deficit to be approximately 115 MW. Summertime peak-hour deficits are forecasted to grow to 204 MW by the summer of 2009. Given the planning criteria to meet the peak-hour load under a 90th percentile water condition and a 95th percentile peak-hour load, a peaking resource capable of being constructed and placed on-line quickly, such as the proposed Evander Andrews plant, would have most likely been included in the 2006 IRP's preferred portfolio had it not been regarded as part of the Company's existing fleet.

The response to this request was prepared by Karl E. Bokenkamp, General Manager Power Supply Operations and Planning, Idaho Power Company, in consultation with Monica B. Moen, Attorney II, Idaho Power Company.

EXHIBIT No. 208

Case No. IPC-E-06-09

D.READING, ICIP

REQUEST NO. 26: Provide estimates by month for the period June 2007 through December 2027 of the number of hours the Evander Andrews plant will be expected to operate to serve Idaho Power's load.

RESPONSE TO REQUEST NO. 26: The number of hours that the Evander Andrews plant will be expected to operate will depend on a number of factors including the ability to purchase and import energy via the existing transmission system, non-weather related economic conditions that could drive load growth to higher than expected levels, the performance of existing generation units, performance of demand side management and energy efficiency programs, potential usage for load following (possibly needed to support wind generation and compensate for potential loss of operational flexibility of the Hells Canyon Complex) and the timing of future resource additions. Since the new Evander Andrews unit is expected to have a lower heat rate than either of the existing Evander Andrews units or the Bennett Mountain unit, it would typically be dispatched first. As a result, the new Evander Andrews unit will most likely operate for more hours than Idaho Power's other combustion turbines.

The response to this request was prepared by Karl E. Bokenkamp, General Manager Power Supply Planning and Operations, Idaho Power Company, in consultation with Barton L. Kline, Senior Attorney, Idaho Power Company.

EXHIBIT No. 209

Case No. IPC-E-06-09

D.READING, ICIP

REQUEST NO. 100: Staff Request No. 26 asked for monthly estimates for the period June 2007-December 2027 of the number of hours the Evander Andrews plant will be expected to operate to serve Idaho Power's load. Idaho Power did not provide any estimate of expected operating hours. For the purposes of answering this request, Staff assumed that the Evander Andrews plant would be added to Idaho Power's portfolio and dispatched in an AURORA simulation using the portfolio selected in the 2006 IRP. Please provide monthly estimates as requested, or if this cannot be done, please explain why.

RESPONSE TO REQUEST NO. 100: As requested, Idaho Power has added the new Evander Andrews plant to its existing portfolio. The resulting portfolio, including the new Evander Andrews plant and the portfolio selected in the 2006 IRP, was dispatched in an Aurora simulation from 2007 through 2032. This Aurora simulation utilized 50th percentile water and average load conditions and 90th percentile peak-hour loads for the Idaho South "bubble", the other WECC zones utilized default Epis load and water conditions, which represent an average or median water and load condition. The new Evander Andrews plant's operating hours as determined by the Aurora simulation are attached hereto as "Response to Request No. 100." The inputs to the Aurora analysis will have a significant impact on of the number of hours that any of the combustion turbines (CTs) are dispatched. In a simulation that utilizes 50th percentile water and average load conditions and 90th percentile peak-hour loads conditions for the Idaho South "bubble" and average or median conditions for the remainder of the WECC, CT operation will be limited. Under more severe conditions for the Idaho South "bubble" and the remainder of the WECC zones, such as 90th

percentile water and 95^{th} percentile peak-hour loads, the CTs are expected to dispatch more frequently.

The response to this request was prepared by Karl E. Bokenkamp, General Manager Power Supply Operations and Planning, Idaho Power Company and Rick Haener, Planning Analyst, Idaho Power Company, in consultation with Monica B. Moen, Attorney II, Idaho Power Company.

IDAHO POWER COMPANY

CASE NO. IPC-E-06-9

FOURTH PRODUCTION REQUEST

OF COMMISSION STAFF

RESPONSE TO

REQUEST NO. 100

Response to Request No. 100

Item	Report Year	Energy(MWh)
Evander Andrew #1	2007	0
Evander Andrew #1	2008	17342
Evander Andrew #1	2009	21813
Evander Andrew #1	2010	17145
Evander Andrew #1	2011	3951
Evander Andrew #1	2012	32
Evander Andrew #1	2013	0
Evander Andrew #1	2014	48
Evander Andrew #1	2015	0
Evander Andrew #1	2016	0
Evander Andrew #1	2017	0
Evander Andrew #1	2018	0
Evander Andrew #1	2019	0
Evander Andrew #1	2020	0
Evander Andrew #1	2021	0
Evander Andrew #1	2022	0
Evander Andrew #1	2023	0
Evander Andrew #1	2024	0
Evander Andrew #1	2025	0
Evander Andrew #1	2026	0
Evander Andrew #1	2027	0
Evander Andrew #1	2028	0
Evander Andrew #1	2029	0
Evander Andrew #1	2030	0
Evander Andrew #1	2031	0
Evander Andrew #1	2032	0

EXHIBIT No. 210

Case No. IPC-E-06-09

D. Reading, ICIP

REQUEST NO. 68: Please provide an update on the status of the negotiation with the cogenerator referred to on page 6, lines 17-20 of Greg Said's direct testimony. How much capacity and energy does Idaho Power expect will be made available if the contract with the cogenerator is executed? If the contract is executed, how will it change Idaho Power's load resource balance and need for power?

RESPONSE TO REQUEST NO. 68:

Negotiations continue between Idaho Power and this proposed cogeneration project. The project has proposed sizes ranging from 35 MW up to 110 MW for this project coupled with continuous 24 hour-a-day operations or fully dispatchable operations.

Both Idaho Power and the proposed project have expended significant effort in these negotiations. However, at this time it would be premature to speculate on the final outcome of these negotiations and the actual impact the resource may have on Idaho Power's energy needs.

The response to this request was prepared by Randy C. Allphin, CSPP Contract Administrator, Idaho Power Company, in consultation with Barton L. Kline, Senior Attorney, Idaho Power Company.

EXHIBIT No. 211

Case No. IPC-E-06-09

D.READING, ICIP

REQUEST FOR PRODUCTION NO. 13: In response to a question at the bottom of page 13 of his direct testimony about the decision to delay the peaking project by one year, Mr. Said states that "the Company evaluated the most prudent use of its resources and determined that other short-term alternatives other than this project could meet the projected peak energy needs for the summer of 2007." Please provide copies of the reverenced evaluation(s) and determination(s). Include any work papers, studies, AURORA model runs and economic evaluations.

RESPONSE TO REQUEST NO. 13: A copy of the analysis that examined expected changes in Idaho Power's forecast surplus/deficit position and a memorandum summarizing the analysis are attached hereto as "Response to Request No. 13."

The response to this request was prepared by Karl E. Bokenkamp, General Manager Power Supply Planning and Operations, Idaho Power Company, in consultation with Barton L. Kline, Senior Attorney, Idaho Power Company.

IDAHO POWER COMPANY

CASE NO. IPC-E-06-9

FIRST PRODUCTION REQUEST

OF INDUSTRIAL CUSTOMERS

RESPONSE TO

REQUEST NO. 13

EXHIBIT No. 214

Case No. IPC-E-06-09

D.READING, ICIP

REQUEST FOR PRODUCTION NO. 19: What is the retail rate impact of Mr. Said's request at page 20 for the Commission to approve inclusion of the total project investment in the Company's rate base for ratemaking purposes? Assume for purposes of answering this question that the total project investment includes 60 million dollars for the generating plant and 22.8 million dollars for associated transmission and substation improvements. Please provide supporting work papers.

RESPONSE TO REQUEST NO. 19: There is no current retail rate impact associated with the Company's application for a Certificate of Convenience and Necessity. The actual incremental revenue requirement to be requested by the Company will depend upon circumstances that exist at the time of an application for recognition of the Evander Andrews project in the Company's rate base, revenue requirement and rates. The earliest a future retail rate impact would occur would probably be in 2008 once the Evander Andrews power plant is in service. An application to change the Company's rates in 2008 to reflect the Evander Andrews power plant could either be a part of a general rate case or a single issue rate case as was the case for inclusion of the Bennett Mountain power plant costs.

In that case, the Company identified \$50.3 million of power plant costs and \$7.7 million of transmission and interconnection facilities costs for a total of \$58.0 million in total project costs. The Company quantified the associated incremental revenue requirement associated with the Bennett Mountain project at \$13.5 million. This quantification included expenses such as property taxes, property insurance and depreciation expenses, but excluded expenses such as operating and maintenance expenses. Power supply expense impacts were likewise not included, but were ultimately captured in PCA computations. The Company has not quantified the incremental revenue requirement associated with the Evander Andrews project. However, assuming the ratio of incremental revenue requirement to total project costs ($13.5 million / $58 million = 23.3 percent) from the Bennett Mountain application might be similar in an Evander Andrews application, an estimated incremental revenue requirement for an $82.8 million project would be $19.3 million.

The response to this request was prepared by Gregory W. Said, Manager of Revenue Requirement, Idaho Power Company, in consultation with Barton L. Kline, Senior Attorney, Idaho Power Company.

DATED at Boise, Idaho, this 11th day of July 2006.

Monica B. Moen

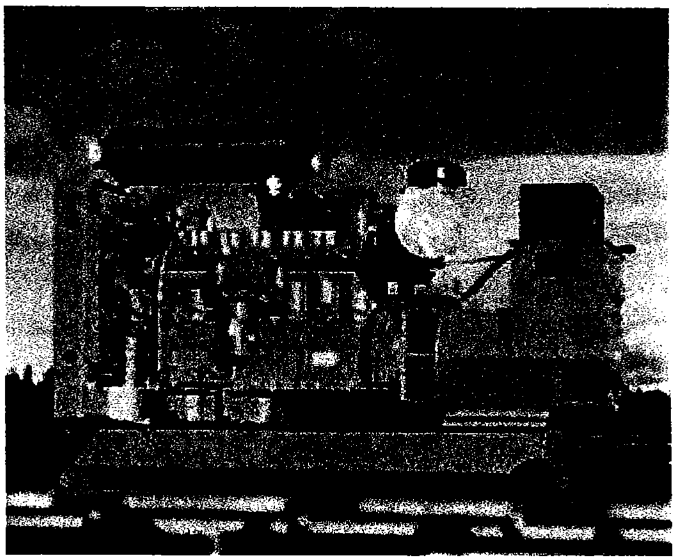
MONICA B. MOEN
Attorney for Idaho Power Company

EXHIBIT No. 218

Case No. IPC-E-06-09

D.READING, ICIP

An Assessment of the Feasibility of Emergency Electrical Generation Units to Serve System Load Requirements



By
Alex Albertine

August 17, 2001
Northwest Power Planning Council

Executive Summary

Over the past year a growing power crisis has emerged across the western states. Recent developments in power management in California have raised particular concerns as the Northwest region both plans and reacts to possible power shortages or extreme price increases. Our heavy reliance on electrical power has left millions of Americans vulnerable to severe consequences of power loss. In order to avoid the California experience of rolling blackouts or the effects of higher wholesale power increases, we must look for creative and innovative ways to both produce greater supplies of electric power, provide incentives for conservation and balance environmental needs simultaneously. Many debates have taken place as to what can be done to improve this situation. Some alternative proposals have been considered. One proposal encourages the use of emergency generators, already installed in a variety of buildings, be used to increase power generation.

This study, which is based upon the need to explore the feasibility of power generation from relatively small generators in individual buildings, is limited in size and scope. Interviews were conducted over an eight-week period with building operators and managers in the city of Portland, Oregon who own or manage emergency generating units. Additional interviews were conducted with personnel from local electric utilities. This study sought first to determine the availability of emergency generators and the amount of power that could be generated. Owners and managers of buildings were questioned as to whether and how they would support using private generation in cooperation with utilities. Issues explored included economic, technical and legal ones relating to the practical use of emergency generators and the incentives and problems in establishing a workable program.

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. This study contacted 70 facilities or approximately 10% of the total available in the city of Portland.

Federal, state and local jurisdictions govern the use of emergency generators. Agencies such as the federal Environmental Protection Agency and state agencies such as the Oregon Department of Environmental Quality have specific requirements and environmental codes that must be met. At the local level, emergency generators are subject to local structural, mechanical and electrical regulations.

From the information gathered 71% of the industrial and commercial building owners or managers indicated that they would be interested or likely interested in contracting with a utility to supply energy to the power grid using their emergency generating capacity. This level of support was qualified by the desire of respondents for support from utility companies and clear economic incentives to participate.

The results of interviews with utility personnel as well as additional research indicated that local utilities are supportive to the idea of using emergency generating capacity to augment present power production. Most utilities are considering innovative programs to increase the power supply, and see the use of emergency generation as a possible option. Some utilities are beginning to develop specific program parameters and consider legal and contract information that would mutually benefit both the owners of emergency generators as well as the utilities. Further, some program elements have specific environmental benefits.

Emergency generators may be used up to 200 hours per year during peak power needs. In exchange for use of the emergency generators, utilities would supply support, maintenance, fuel and equipment to fully maintain the generators as well as build a centralized and parallel power supply. Building owners would be secure in knowing that they have guaranteed, dependable and non-interruptable power from well-maintained and tested emergency generators.

If the results of this survey are extrapolated region-wide there is significant generating capacity available using the capacity in emergency generators. An estimated 3.7 gigawatts of generating capacity is believed to be available. This additional power provided at reasonable cost, both economically and environmentally offer an important opportunity to meet the power needs of a growing region.

Table of Contents

An Assessment of the Feasibility of Emergency Electrical Generation Units to Serve System Load Requirements

Millions of Americans, often without thought, rely on our complex electrical power system to meet their daily needs. Without electrical power modern life and the completion of simple daily tasks becomes impossible. Electrical power is the essential backbone of America's culture. Unfortunately, this reliance has left citizens vulnerable to the power system and the negative effects when it does not work properly. Presently the northwestern part of the United States is experiencing a lessening in availability of electrical power. Prices of wholesale power are increasing dramatically. These prices are predicted to continue to be high throughout the next several years. Economic and population growth, poor water conditions, lack of customer incentives to conserve, high natural gas prices and a dysfunctional deregulated power industry in California has resulted in the deterioration of the electrical power system. This situation must be improved to continue the high standard of living Americans enjoy.

Many debates have taken place in a search for ways to improve this situation. No single clear answer has been found, but many alternative proposals have been considered. One idea, the focus of this study, is the use of emergency generation units to produce the demanded amount of power that the utilities are unable to provide. Many commercial and industrial facilities are already equipped with emergency power generation units. These units, which run on diesel fuel, are installed and are used in case of an emergency when the grid that usually provides the electrical power is temporarily out of service. It has been proposed that these emergency generating units also be put in operation to supply power during times of peak demand. The question of whether it is feasible to use these units as part-time power generators is the objective of this study proposed by the Northwest Power Planning Council.

The Northwest Power Planning Council is an interstate compact agency responsible for the assessment of electric power and fish and wildlife issues affecting the states of Idaho, Montana, Oregon and Washington. The Council makes policy recommendations at the request of the governors, legislators, congressional delegation and the Bonneville Power Administration.

This study is based on interviews of facilities operators who own emergency generating units and the utilities that support the power grid. The first goal of the study is to evaluate the current conditions of the emergency power generators. For example, where generators are located, amount of generating capacity, who controls their use, and under what circumstances generators are currently employed, are all questions addressed by the study. Since little was known about the emergency generating units, finding current information about these generators was essential in finding out how they might be used to offset the power demand.

The second goal of the study is to analyze the feasibility of employing emergency generators fulltime or on a part-time basis as needed. In question is the economic viability of keeping generators running for a longer than normal period of time. The study examines the impact on the utility, and if it is economically feasible for the utility company to pay for extra equipment, contracts, and servicing for emergency generators. The study also addresses the environmental quality issues that appear when the generators are in use. They are noisy and release large amounts of particle waste into the air. The generators also require fuel onsite for their operation, which, when running the generators more often, will result in the need for more onsite diesel fuel.

Other complications may also arise. Health and safety issues may offer challenges. There are also several laws, regulations and institutional constraints on use of emergency generators. It is important to take into account these regulations and the actions necessary to modify regulations that prohibit the use of generators as power producers. At present, the primary purpose of these units is to provide electricity to the customer in case of service interruption. If emergency generators were to be used to augment system loads, as addressed in this study, the generators would no longer be considered emergency generators, but power generators and be subject to a different level of federal and state requirements.

Electricity is provided by the power producer, passed to the utility, and then to the consumer. In an ideal circumstance this is how the power industry would work on a simplified level. The current problem is that it now costs the utility too much to buy the power from the producer due to increased demand and impacts from additional economic factors and unpredicted events. Because the utility must supply energy to consumers, it will look for other options to produce power more efficiently. As shown in figure one, below, demand tends to increase during mid-day. If the utility is only able to fulfill part of their demand during mid-day the result would be blackouts. This study will review the use of emergency generators by the utility to fulfill the demanded amount of power as shown below.

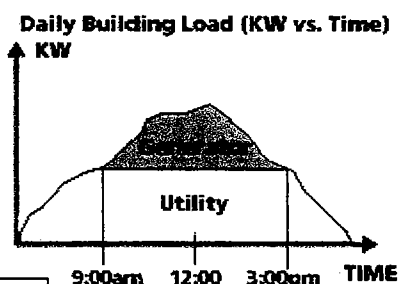


Fig. 1 Typical load profile showing use of engine generator during peak periods.

The generator is able to fill the demanded amount of power.

This beginning study seeks to gather baseline data in regards to emergency power generation use. Conclusions are preliminary and based on limited data and estimated numbers. Yet, this information can provide groundwork for even more future research. It is clear that if the full extent of emergency generation's potential is to be realized, a more in-depth and broader study must be performed. However, it is my intention to provide the most recent and exact information possible. With this information gathered an estimate of generation potential has been made. Hopefully with this new information, producers, utilities and consumers will begin to prepare for innovative changes in the power industry.

Evaluating Conditions of Emergency Generation Facilities

Types of Emergency Generator Units

Emergency generators come in a variety of types and have varying amounts of kilowatt (kW or 1000 watt) capacity. The main manufacturers of emergency generators are Caterpillar, Cummins, Detroit Diesel, Perkins, and Deutz. Photos of the different generators, except Perkins, are included in appendices four, five, six and seven respectively. The average commercial grade generator will produce anywhere from 150 kW to 800 kW. This is the standard range for generators installed in commercial buildings to support emergency equipment, such as lighting or elevators. For smaller buildings or those who only need generation for emergency lighting there are smaller generators available ranging from 50 to 150 kW. Buildings with tenants that require larger generation, or industrial plants, may use generators producing 800 kW to 4 megawatts (MW or 1000 kW). Any generator larger than 4 MW is considered to be a power plant in itself.

Generators are a huge investment for a building owner. A standard 200 kW generator costs around $21,000. 400 kW generators cost about three times as much. There are also added expenditures such as an auto start panel, the auto-transfer switches, fuel tanks, various permits, installation and shipping. This does not include maintenance, which is estimated to be ten to twenty thousand dollars a year for an 800 kW generator. This maintenance figure also includes the amount spent on periodic testing.

Where Generators are Found

Human safety is the number-one reason for the installation of emergency generation units into office buildings. Federal law mandates the existence of emergency lighting in any commercial, industrial or public facility. Emergency lighting can be supplied two different ways. First, a facility may install emergency batteries to supply lighting during a power failure. Batteries are cheaper for the owners to purchase. They are also more environmentally friendly. Emergency battery systems recharge themselves when power is on and do not use any excess fossil fuels, leave any discharge or any particle waste when running. One drawback of emergency battery systems is that they are not as powerful since each can only produce approximately 50 kW. However, batteries can be stacked to reach higher capacities. Also, they are unable to support the building needs for more than a day or so at peak load.

The second form of emergency lighting is through emergency generation units. These units come in all forms and sizes and can produce up to 4 MW of electrical energy. The benefit of an emergency generator is that it can be used to supply emergency lighting, backup the elevator system, run the computer system, or in an industrial building the generator can run the equipment needed to continue production. Generator use has flexibility and can be set up to run any electrical device during an outage. Even though emergency generators cost several thousands of dollars more than battery systems, their ability to continue to run building systems can save tenants lost revenue. In many cases generators can pay for their purchase and operation costs in a few years by the amount of revenue produced from not having to stop production during a power outage.

Emergency generators can be found in hospitals, office buildings, high schools, colleges and universities, jails, public safety facilities (Police, fire, emergency rescue), military facilities, airports, seaports, ski resorts, industrial production facilities, telecommunication facilities, or anywhere else that may need back up power to continue work.

Determining Generator Location, Type and Capacity

One of the goals of this study is to calculate the number, type and capacity of emergency generators available for electrical production in the Northwest. From those numbers I hoped to estimate the generation potential in kilowatts. Originally it was thought that by contacting building managers in buildings with known emergency generators I would be able to find the information necessary for the study. I also hoped to gather information from previous building studies, which along with my survey information of the city of Portland area, would be used to determine the number of generators within the four states of the Northwest Power Planning Council's region. The previous building studies would show me how to extrapolate my generator information from Portland to include all of the four states.

Initially I had no idea as to how we would be able to get the names and phone numbers of so many building managers for the many different types of buildings in Portland. But after contacting the Building Owners and Managers Association (BOMA), they provided me with a list of building managers and their phone numbers. I then contacted the building managers and interviewed them using the questionnaire I produced. (See Appendix 1) Unfortunately, several problems arose. First the list provided by BOMA only included commercial buildings, and it was necessary for me to contact all types of buildings. Secondly, the list did not indicate information on who had emergency generation capabilities. Out of the seven hundred buildings listed for Downtown Portland I had no idea how many or who specifically had the generators.

In my survey I interviewed managers in 70 buildings. (10% of the 700 available.) Since buildings are not legally required to have generators (See codes and requirements p. 9) I found that only about 20 percent of the buildings I surveyed owned generators. This small of number was too small to be statistically used to estimate generation kilowatt capacity in the four northwestern states.

Other errors also appeared. The previous building studies I had hoped to use were at least ten years old. Numbers from these old studies made their use for estimation inaccurate and unusable.

In the interest of determining a more accurate number of generators, I requested from Caterpillar Inc. a list or number of generators installed around the four states. I knew Caterpillar periodically prepared a list of domestic generating units installed around the world. Caterpillar's list was last updated Fall 2000 and holds the most accurate data as to how many generators are installed in Washington, Oregon, Idaho, and Montana. Caterpillar uses the list to enable its regional dealers to identify maintenance opportunities. The list is a comprehensive list, in that the list includes not only Caterpillar brand equipment, but also generating sets manufactured by other companies. The data provided by Caterpillar is presented below in table 1.

Table 1

Numbers refer to the amounts of generators of a particular kilowatt production size installed in a state.

Range (kW) State	50-70	71-150	151-300	301-700	701-1200	1201-200	2000+	Total
Oregon	2,143	2,058	1,960	811	530	470	176	8,148
Washington	3,699	3,553	4,060	1,400	916	812	304	14,744
Idaho	321	494	323	122	80	71	27	1,438
Montana	547	621	538	222	146	129	48	2251
Total	6,710	6,726	6,881	2555	1672	1482	555	26,581

Table 1 shows that at last count, the state of Oregon had as many as 2,143 individual small generating units, posting a capacity rating of between 50 and 70 kilowatts. The total number of standby generation sets rises to 8,148 when we take into account units of a size ranging from 50 to 2000+ kW.

Obviously, not all of the generating units identified in Table 1 are available for delivering electricity into the grid. Some may not be operable; others may be used on remote sites. Further, the data in Table 1 may not be completely accurate, even though the data is based on an actual count of generator units as opposed to my original plan. However, I was assured by the manufacturer that the vast majority of these generators are serving as emergency generators standing ready to operate when the local distribution grid stops delivering electricity to a customer location. Typically such calls for emergency generation occur when there is a distribution fault or when rolling blackouts have been implemented.

How much power is possible?

Finding out exactly how much emergency generation power or capacity is available is one of the main goals of the study. Assuming that we get full cooperation from building managers and do not run into any regulatory problems the total generation power becomes the maximum power available from emergency generation. In the table below I evaluate the total production capacity of the generation units indicated in Table 1. To calculate total production capacity for the units in each of the first six columns, I have taken the midpoint of the range and assigned that number to the column as the capacity. For the last column, with generator capacity in excess of 2000 kW, I have used 3000 kW as the average capacity of this column. It is then simple multiplication. For instance, Oregon's 2,143 generators producing 50-70 kW results in 2,143 x 60 = 128,580 kilowatts or about 129 megawatts. Based on this evaluation method, there are 9,528 megawatts or 9.5 gigawatts of electrical distributed generation installed in the four northwestern states. 9.5 gigawatts are the maximum amount of electrical capacity from emergency generators available in the northwestern states. This number is high enough to cover the expected amount of power generation needed in the Northwest throughout the next several years. 9500 MW is about a quarter of the present utility generating capacity in the Northwest.

Table 2 The numbers refer to the amount of production capacity at each generator size.

Range (kW)	50-70	71-150	151-300	301-700	701-1200	1201-2000	2001+	Total
Capacity (kW) State	60	110	220	500	950	1600	3000	
Oregon	129	226	431	406	504	752	528	2,975
Washington	222	391	893	700	870	1,299	912	5,287
Idaho	19	54	71	61	76	114	81	476
Montana	33	68	118	111	139	206	114	820
Total	403	739	1513	1278	1589	2371	1635	9,528

Other Necessary Equipment

Automatic Transfer Switch and Parallel Switching Gear

The Automatic Transfer Switch (ATS) is a key component of any emergency and standby generator system. It is the device that monitors the sources and transfers the critical load from the preferred or normal source, to the alternate, or emergency source. Automatic Transfer Switches can switch between alternative and normal power sources with only a thousandth of a second interruption. The interruption is so small the tenant rarely notices it. If a company, such as a microchip fabrication plant needed switching gear they would need to be on parallel gear already. Because of its importance, it is imperative that generator owners be aware of the many transfer scenarios and the solutions to the various standby power applications. Automatic transfer switches are a vital but expensive part of an emergency generation system. Without the switching gear, personnel from the building where the generator is located would have to turn on the generator manually. A model of the automatic switching gear is shown below.

EXHIBIT No. 219

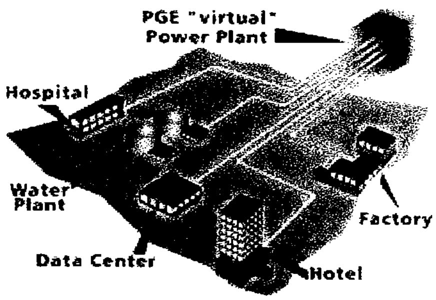
Case No. IPC-E-06-09

D.READING, ICIP

Dispatchable Standby Generation

Capture enhanced reliability and operational savings from your backup elec generation system.

If your business requires standby electric generation to ensure vital production or performance, you know the daily reality: constant maintenance of your backup sys hope that it will perform when you need it.



From PGE's control center, a dispatcher can start any or all of the standby generators within the system. Up to 100 megawatts of power can be generated during peak hours.

For most of the year, however, the only thi backup system generates is a stream of o| and maintenance expenses.

PGE's Dispatchable Standby Generation ț your standby generators to work for up to · annually to meet peak power demands — picks up all your maintenance and fuel exț

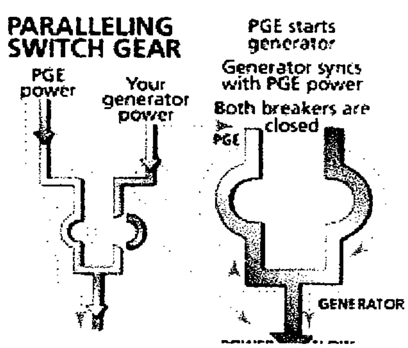
Your generator is always available to back facility and will operate synchronized and i with PGE power so there is no service inte

For the option of running your generators when needed, PGE will:

- Upgrade switchgear and install control and communications hardware at nc increasing reliability and improving control of your system.
- Assume all maintenance and operation costs for your system, eliminating y fuel, repairs, tune-ups, oil changes, filter replacements and overhauls.
- Provide additional sound attenuation, if needed, quieting the generator syst
- Provide additional fuel storage, if needed, expanding your operating time dı weather-related, long-term power outages.
- Test your system at least once a month under full load; frequent full-load te ensures the generator will operate successfully during an outage and is bet engine.

A powerful network

PGE equips your standby generator with paralleling switchgear, allowing the unit t operated in synchronization with the electric distribution system. Qualifying comm industrial customers (those with standby ger 250 kilowatts and up) are networked with PG communications and power control system. units can be monitored and dispatched from control center.



In case of an outage, the standby generator it normally would, providing backup power to for the duration of the outage. However, whe returns to the grid, your facility moves back t power without additional interruption.

POWER FLOW

Program participants pay standard electric ra power used, regardless of where it's being generated. PGE pays all the fuel costs standby generators, even during an outage, adding to the operational savings.

So how does this work?

Read our **FAQ**, which answers common questions about how the program works, offering the DSG program and how your business can take advantage of this savi opportunity.

Unleash the full potential of your standby generator

Interested? At your request, we will provide a detailed analysis and proposal tailor business requirements. Please contact your PGE representative or **e-mail us**. Yo call Mark Osborn, DSG program manager, at 503-464-8347.

If you are considering purchasing a new generator or upgrading to a larger system generation, PGE provides convenient financing on request. Financing can be add monthly electric bill.

FAQ

Q: Why is PGE offering the Dispatchable Standby Generation (DSG) program?

- The tight supply of electricity and resulting high prices have created new business opportunities for PGE customers who can simultaneously use power, while making more power available in PGE's territory. The DSG program improves a participant's bottom line by having PGE:
  - Cover the operating and maintenance costs of the DSG power system
  - Contribute to the customer's standby generator system installation

  PGE benefits by accessing new power resources for all its customers. By linking many generators to the electric distribution system and turning them on at peak demand hours, PGE and program participants are helping keep the price of power down and the supply up with an innovative business relationship.

Q: What happens if we need power at the same time PGE is using the DSG system?

- Your backup generator is always available to serve you without interruption. Your generator and PGE are synchronized and operate in parallel, automatically backing each other up. If one system fails, the other takes over — significantly increasing your reliability.

  The DSG system is set up so your facility's loads are automatically served first and then any excess power you generate flows into the PGE system. For example, if your building load is 1,000 kilowatts, and the generator is putting out 1,500 kilowatts, only 500 kilowatts are serving other PGE customers.

Q: Will the DSG program put more wear and tear on my company's generator?

- The DSG program will probably extend the life of your backup/emergency power system. The program operators regularly start up the generators and test them at full load. More frequent full load runs are better for the diesel engines. The tests also save the costs of load bank testing and assure your organization that the equipment will start up and function properly in a power outage.

Q: Will PGE help pay for new generators? Does PGE help if I'm installing new generators?

- The generators themselves are not funded by PGE. However, whether you are building a new facility with backup power, adding generators or upgrading your switch gear, PGE helps fund the installation. PGE provides most of the cost for the latest generator control and paralleling circuit breaker technology. Many high-tech companies are already using this equipment for seamless transition from generators to the power grid.

Q: Can you assure us that our emergency power system is maintained to our standards of reliability and quality?

- Yes, your facility's staff and PGE will jointly decide on the most qualified maintenance provider. This may be your existing provider, your own staff or a new provider that best meets your needs. Our agreement with maintenance providers will include annual performance reviews and if they are not performing at the levels we expect, we can agree to change providers.

Q: Who is responsible for maintenance and repair?

- This is another win-win aspect of the program for participating businesses, institutions and PGE. All regular maintenance and any repair bills are paid by PGE. The utility sees this as a reasonable cost to assure that your generator is available at all times to participate in the program, and it lowers your cost of doing business. We estimate that this may easily save $50,000 to $100,000 over a five-year period.

  PGE has created the DSG program with the highest standards. Should your equipment fail to function as required for your emergency/backup use, the maintenance provider selected by you and PGE will begin diagnosing the problem within four hours of notification. If appropriate, the provider will then repair or replace the equipment (at PGE's discretion) with comparable items as required to meet your system's needs.

Q: Who pays for fuel?

- PGE pays for fuel regardless of whether the fuel was used only for your needs or to serve the utility distribution system. We do require the use of transportation grade, low-sulfur, diesel fuel.

Q: Can I still participate if I choose to buy power from an independent supplier?

- Under Oregon's restructuring law, you can choose to purchase your power from an independent provide. If you make this choice, you can still take advantage of the DSG program. You, PGE and your independent supplier would negotiate an agreement, which would provide accurate billing and properly account for the power used by your facility, even when the generators are operating.

Q: Are there any regulatory or tax issues I should be aware of?

- Participating in the DSG program will not affect your taxes. Because PGE will own a portion of the system of which the generators are a part, the output of the generators will be considered PGE power. PGE will also handle all power regulation issues related to the operation of your DSG power system.

Q: Under what circumstances would my organization have to reimburse PGE for its investment?

- PGE is providing a significant investment to upgrade your property. PGE is counting on your generation to maintain an efficient power system and reduce costs. If you cancel the agreement without cause or without proper notice, most of the equipment would typically remain with you and you would be responsible for reimbursing PGE for the value of that equipment.

  If PGE cancels the agreement, PGE will remove any PGE equipment and leave your facility in such condition as will enable you to operate the generators for your own backup use. Under these circumstances, no equipment reimbursement would be required.

Q: Can a business cancel the DSG agreement?

- In the unlikely event that PGE fails to maintain or repair the equipment as required in the agreement, you may cancel the contract before its normal expiration date. As mentioned above, the maintenance service provider is required to begin diagnosing a problem within four hours. If a problem cannot be fixed within 30 days, you would have the option to terminate the agreement.

Q: What happens if the actual project cost is greater than PGE's projections because of unforeseen conditions?

- In a retrofit installation or for PGE owned equipment, PGE will be responsible for all cost over-runs related to items installed under the Dispatchable Generation Agreement. With a new facility or new generator plant, where you would have primary responsibility, we would negotiate an appropriate cost sharing solution.

Q: How is PGE handling the environmental impact of the DSG program?

- PGE cares a great deal about the environment. We will be installing oxidation catalysts on all DSG program engine-generators. These catalysts significantly reduce carbon monoxide (CO), hydrocarbons (HC) and odor from the diesel engines. Research is also underway to explore new ways to reduce nitrogen oxides (NO_x) in the engines we use for the program. PGE is also doing extensive research on the use of dual fuels. This could create opportunities to burn natural gas instead of diesel oil in many generators, significantly reducing emissions into the air. Every generating system in the program is issued a permit by the Oregon Department of Environmental quality, assuring that the engines are operating within standards.

Q: How can I learn more about PGE's Dispatchable Standby Generation program?

- Please contact your PGE representative or **e-mail us**. You may also call Mark Osborn, DSG program manager, at 503-464-8347.

EXHIBIT No. 220

Case No. IPC-E-06-09

D.READING, ICIP

Portland General Electric

Sign In | Manage Accounts | View Bills

PGE Home >> Customer News

Customer News

Power Report

Power Report

August/September 2006 Power Report Newsletter

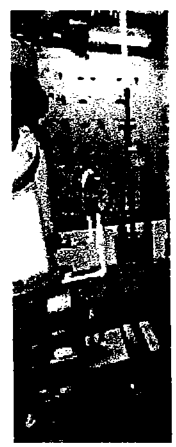
Articles in this issue:

Motors: Rewind or Replace

When to upgrade to a premium-efficiency model

When you have a motor that fails, you're faced with deciding whether to repair it o That decision depends on a number of factors, including repair versus replacemeı efficiency of the existing industrial motor, availability of a new motor and the cost c

If you are ready to replace a motor, it's a good idea to consider upgrading to a premium-efficiency model. When you install a qualifying motor, 200 hp or less, you may be eligible for a cash incentive of $10/hp from Energy Trust of Oregon. These incentives do not require pre-approval, but applications should be submitted as soon as practical after purchase. (Motors over 200 hp are also eligible for incentives, but they must be approved by Energy Trust prior to installation.)



Energy expert Doı assists customers with motors.

Bottom line, the incentive can help provide a good payback on motors that operate a lot, and a premium-efficiency motor can reduce your monthly energy usage and operation costs.

"Even if you don't need to replace motors now, it's a good idea to plan ahead," says Doug Findlay of PGE Customer Technical Services. "Look at your applications, identify what you will need and pencil it out. That way, when replacement time comes, you can move quickly and feel confident you're making the right decision."

PGE can help you with this process by looking at your current motor systems to hı identify ways to maximize energy efficiency. Just contact your PGE representative

Center, is also the nation's greenest.

The Clean Wind purchase helps in Providence Newberg Medical Center's application to become a LEED (Leadershir and Environmental Design) Gold certified building. This certification by the U.S. G Council would make the structure the first LEED Gold hospital in the country. The presents this award only to those buildings that meet the highest standards of low environmental impact and energy efficiency.

"Building a green structure and using renewable power supports health care indus for patient care and healthy workplaces and demonstrates the benefits of environr friendly practices to the public," says Larry Bowe, chief executive of Providence N Medical Center.

Learn more about the Providence purchase in our **News Room**. To learn more ab benefits of Clean Wind power for your organization, talk with your PGE representa

Standby generation picks up extra load during heat wave

As the demand for power rose with the soaring temperatures on July 24, PGE's D Standby Generation program rolled into action. PGE called upon a network of star generators at companies throughout our service territory to help meet peak demai

Salem dual-fu

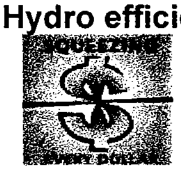
This innovative distributed resource program helped PGE avoid spot purchase power costs on the open market, where supplies were extremely tight and the rising temperatures pushed megawatt prices into the stratosphere.

"We were able to supply 25.5 megawatts of electricity during a period of peak load requirements," says Mark Osborn, who manages PGE's Dispatchable Standby Generation program.

The program puts a customer's standby generators to work for up to 400 hours ar meet peak power demands — and PGE picks up all maintenance and fuel expens

More than 33 generators at 21 organizations are enlisted in the program. Most rec generators at the Oregon Military Department's new headquarters in Salem becar dual-fuel (diesel and natural gas) generators in the program. Read more about **Di Standby Generation**.

Hydro efficiencies help control costs



PGE works hard to control costs and serve customers efficiently. I few examples of how we are saving money in our hydro operation

Pelton Hydro Plant: New switches speed transformer repairs, save labor cos
At our Pelton plant, new switches were installed that make it much faster to switch transformer to a backup transformer when repairs are needed. The new equipmer the time-consuming task of having to move the massive transformers around. This and overtime costs and reduces the amount of generation lost during maintenanc About $15,000 for each future maintenance event.

Portland Hydro Project:
$2 million savings, plus reliability improvements
In the Bull Run watershed — the source of Portland's drinking water — PGE oper small dams owned by the City of Portland's water bureau. This spring, PGE comp

EXHIBIT No. 221

Case No. IPC-E-06-09

D.READING, ICIP

Portland General Electric
2002 Integrated Resource Plan
Final Action Plan Update

Portland General Electric

March 23, 2006

objective of the Commission to remove barriers to the development of distributed generation.

We continue to evaluate these issues, participate in local and regional forums, and maintain an open dialogue with customers and interested parties with respect to CHP. By doing so, we hope to increase our awareness and understanding of the market potential, assess ways to overcome barriers and seek technically viable and cost-effective CHP opportunities to help meet our future resource needs.

Dispatchable Standby Generation

In the 2002 IRP we listed Dispatchable Standby Generation (DSG) as one of our capacity resources.[1] As part of our acknowledged action items, we committed to developing a 30 MW "virtual peaking plant" by the winter of 2006-07. By the end of 2005 we had 29 MW on line and available for dispatch. We have another 16 MW signed or under construction, for a total of 45 MW of dispatchable standby generation available by the end of 2007.

We have found that customer enthusiasm and adoption rates for this program have been higher than we originally anticipated. The high levels of customer interest and participation have allowed PGE to establish one of the most successful customer-based capacity programs of its kind. This option, because of its distributed nature, also provides reliability benefits for PGE and the host customers.

DSG is a high quality, cost-effective capacity resource that also serves as reserve capacity. The projects pursued were either new installations or major rehabilitations that represented lost opportunities if the construction window was missed.

Since we have received inquiries and further interest from customers beyond our current implementation, we believe that the DSG program could potentially be expanded to help meet more of PGE's future capacity needs. Ultimately, we may be able to develop as much as 100 MW, depending on future economics and customer adoption rates.

Because this resource relies on the operation of diesel-fueled, back-up generators at non-residential customer sites, we are limited in the number of hours per year that we can operate each plant. However, this limitation does not impair the effectiveness of DSG as a capacity option,

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[1] See Appendix K, p. 179.

as we only intend to dispatch the resource during infrequent super-peak events and to meet PGE and customer reliability needs.

Energy Trust of Oregon Master Service Agreement

In 2005 PGE executed a Master Funding Agreement with the ETO that will expedite our acquisition of future renewables projects. The agreement designated ETO funds to assist PGE in acquiring new renewable energy resources by subsidizing any above-market costs. The agreement also outlines all key terms and conditions for requesting, securing and administering subsidy funds for such projects.

Joint Letter to Oregon's Delegation

We participated in a joint letter to Oregon's federal congressional delegation urging the renewal of the PTC for renewables. Both U.S. Senators voted for the subsequent extension. The other co-signers included: Puget Sound Energy; PacifiCorp; NorthWestern Corporation; Citizens' Utility Board of Oregon; and the Washington State Office of Community, Trade and Economic Development (see appendix).

We joined the Legislative Committee of the American Wind Energy Association (AWEA) in early 2005 and worked with them and other members to secure PTC extension. We also visited our Congressional delegation on the Ways and Means Committee twice in Washington, D.C. to discuss these issues.

EXHIBIT No. 222

Case No. IPC-E-06-09

D.READING, ICIP

Stakeholder Dialogue No. 4

PGE's 2006 Integrated Resource Plan

July 25, 2006

Portland General Electric

Stakeholder Dialogue Overview

Brian Kuehne

April

- PGE's future resource needs
- Scope of the 2006 Integrated Resource Plan

May

- Customer outreach studies
- Demand-side management: options and incentives
- Potential state and federal issues: climate change policies, new renewable standards

June

- New generation options and costs: wind, next generation nuclear, natural gas, geothermal, traditional and gasified coal, biomass
- Fossil fuels fundamentals and forecasts

July

- 2006 IRP modeling approach: trial portfolios, risk metrics, stochastic inputs, scenarios, performance metrics
- Transmission considerations
- Capacity resource options

September

- Analysis of trial portfolio scenarios; rankings by cost and other performance metrics

Portland General Electric

Capacity Resource Options

1. **Resources Available Year Round:**
   - Simple cycle turbines
   - Capacity contracts
   - Natural gas reciprocating engines
2. **Seasonal Resources:**
   - Exchange contracts
   - Capacity contracts
3. **Limited Operation:**
   - Dispatchable Stand-by Generation (DSG)
   - Load control
4. **Non-Firm:**
   - Demand buy-back
   - Spot market purchases of electricity

Portland General Electric

Capacity Resource Costs: Supply Side Main Options
Preliminary Estimates

Resource	Potential by 2012	Capital Cost (2006$/kW-yr)	O&M (2006$/kW-yr)	Fuel Risk	Trans-Mission Risk	Notes
1. Year-round						
SCCT	47MW per unit	$50	$19	Yes	Yes	Variable cost for these options depends on cost of natural gas
SCCT	170MW per unit	$41	$19	Yes	Yes	
Nat.Gas Reciprocating Engines	8 MW per unit	$77	$18	Yes	Yes	
2. Seasonal						Actual availability, potential, and cost dependent on regional markets and seasonal supply balance.
Exchanges	unknown	unknown	-	Yes/No	Yes	
Capacity Contracts	unknown	unknown	-	Yes/No	Yes	

Portland General Electric

Capacity Resource Costs: Limited Operation
Preliminary Estimates

Resource	Potential by 2012	Capital Cost (2006$/kW-yr)	O&M (2006$/kW-yr)	Fuel Risk	Trans-mission Risk	Notes
3. Limited opportunity						
DSG	125 MW (max. potential) (typically contracted for 400 h/yr)	$23	$7	Yes	No	Fuel risk; technical and site limitations
LC – Res. Water Heat	7 MW, max 100 h/yr	$111	$76	No	No	RFP/RFI likely needed for cost and availability assessment. Typically, utilities are limited in the no. of hours of operation.
LC – Res. Space heat	2 MW, max 100 h/yr	$74	$38	No	No	
LC – Res. Air Cond.	8 MW, max 50 h/yr	$57	$35	No	No	
LC – Non Res.	unknown	unknown	unknown	No	No	

Portland General Electric

Capacity Resources: Summary
Expected Availability

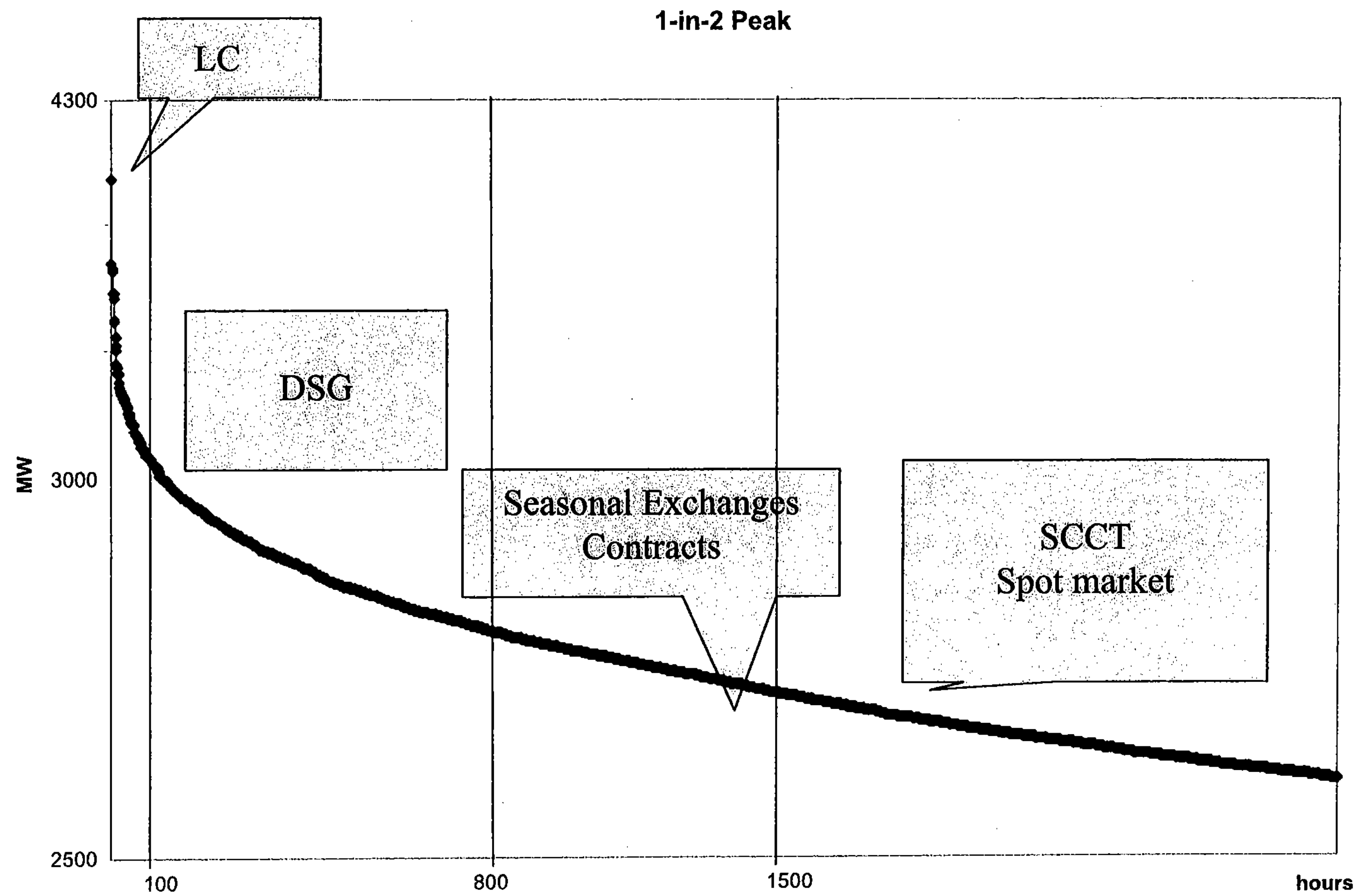

EXHIBIT No. 223

Case No. IPC-E-06-09

D.READING, ICIP

REQUEST FOR PRODUCTION NO. 46: Please describe any efforts Idaho Power has made to look into the use of emergency generators (i.e. emergency back-up generation installed throughout the region in commercial or industrial facilities) to meet or reduce peak loads. Please provide any relevant analyses, documentation, and correspondence.

RESPONSE TO REQUEST NO. 46:

During the energy crisis in 2001, Idaho Power made customer inquiries regarding the installation of back-up generators installed in our service territory. However, no documentation of these inquiries has been retained.

During this same time period, Idaho Power implemented the Energy Buy Back program (Schedule 22) that allowed commercial and industrial customers an opportunity to voluntarily reduce their electric loads in exchange for payment from the Company. Schedule 22 was available to customers who were able to reduce their electric load by at least 1,000 kW at one metering point. Eligible customers who were known to have back-up generation were targeted for program participation. The program expired in March 2002. A copy of the Program Performance Report filed with the Commission in May 2002 is attached hereto as "Response to Request No. 46."

The response to this request was prepared by Maggie Brilz, Manager, Rate Design, Idaho Power Company, in consultation with Monica Moen, Attorney II, Idaho Power Company

DATED at Boise, Idaho, this 22nd day of September 2006.

Monica B. Moen

MONICA B. MOEN
Attorney for Idaho Power Company

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on this 22nd day of September 2006, I served a true and correct copy of the within and foregoing IDAHO POWER COMPANY'S RESPONSE TO THE THIRD PRODUCTION REQUEST OF INDUSTRIAL CUSTOMERS OF IDAHO POWER upon the following named parties by the method indicated below, and addressed to the following:

Commission Staff Donovan Walker Deputy Attorney General Idaho Public Utilities Commission 472 W. Washington (83702) P.O. Box 83720 Boise, Idaho 83720-0074	X Hand Delivered ___ U.S. Mail ___ Overnight Mail ___ FAX X Email Donovan.walker@puc.idaho.gov
Industrial Customers of Idaho Power Peter J. Richardson, Esq. Richardson & O'Leary 515 N. 27th Street P.O. Box 7218 Boise, Idaho 83702 Don Reading Ben Johnson Associates 6070 Hill Road Boise, Idaho 83702	___ Hand Delivered X U.S. Mail ___ Overnight Mail ___ FAX X Email peter@richardsonandoleary.com ___ Hand Delivered X U.S. Mail ___ Overnight Mail ___ FAX X Email dreading@mindspring.com

Monica B. Moen

Monica B. Moen

IDAHO POWER COMPANY

CASE NO. IPC-E-06-9

THIRD PRODUCTION REQUEST

OF INDUSTRIAL CUSTOMERS

RESPONSE TO

REQUEST NO. 46

IDAHO POWER
An IDACORP Company

Idaho Power Energy Exchange

Schedule 22

Program Performance Report

May 2002

Background

On February 12, 2001, Idaho Power Company ("Company") filed an application (Case No. IPC-E-01-04) with the Idaho Public Utilities Commission ("IPUC") requesting approval of Tariff Schedule 22, Energy Buy Back Temporary Program ("Energy Exchange"). The IPUC approved Schedule 22 in Order No. 28707 dated April 24, 2001.

The Energy Exchange was a voluntary load reduction program for commercial, industrial or large irrigation customers. Through this program, Idaho Power Company would credit a customer's account for reducing electrical load during specific hours. The goal of this program was to reduce Idaho Power's system peak(s) and to reduce the amount of high priced wholesale power the Company purchased. The Energy Exchange was intended to benefit the Company and the participating customers, as well as all Idaho Power customers.

The Energy Exchange was modeled after similar successful programs at other utilities in the Northwest and across the country. Through the Idaho Power Energy Exchange, an interactive website, Idaho Power would declare an Exchange Event. An Exchange Event was a set of hours during which Idaho Power would ask participants to reduce their electric load during specific hours on specific days in exchange for a credit on their bill. Hourly prices would be approximately one-half of wholesale market prices. Exchange Events would be announced for the day of, day ahead, or two days ahead of an Event. Participating customers could then specify through the Idaho Power Energy Exchange which hours and days that they wished to reduce their load. Idaho Power could then accept or reject the offer of load reduction. Exchange Events were guaranteed to be a minimum of two consecutive hours and if they participated, customers would commit to a load reduction for at least two consecutive hours.

Participating customers were required to be able to reduce their electrical load by 1,000 kW at each meter point, have Internet access, and have interval meters. Participants were encouraged to keep their load reduction within 15% of the amount they committed to reduce. The Tariff stipulated that Idaho Power would credit customers for up to 115% of the committed reduction but penalize them for reducing their load by less than 85% of the committed reduction.

Results

Idaho Power has chosen not to request an extension of Tariff Schedule 22. A series of events in the western wholesale energy market, a lack of participation, and the costs of continuing the Idaho Power Energy Exchange have made this program economically impractical to continue.

To facilitate the Energy Exchange Idaho Power contracted with a third party service provider, Apogee Interactive, to design and administer the Idaho Power Energy Exchange website. Idaho Power and Apogee Interactive finalized a services agreement on June 11, 2001. The Idaho Power Energy Exchange became active on June 15, 2001.

On June 19, 2001 the Federal Energy Regulatory Commission (FERC) approved the west-wide mitigation plan for wholesale electric markets. In this plan FERC capped western wholesale electric prices at a level based on the market clearing prices in California during stage 1 emergencies. This price cap was and still is approximately $91 per megawatt hour. In the Energy Exchange, Idaho Power anticipated offering customers hourly bid prices equal to approximately one-half of wholesale market price during Exchange Events. Within this bid price framework, the western price cap of $91 per megawatt hour resulted in a maximum bid price of about $45 per megawatt hour. This price was too low to make it economically feasible for participating customers to reduce their load. While the approval of the western price caps lowered western wholesale electric prices, overall energy conservation in the Northwest and other load reduction programs reduced demand for wholesale power. These events helped make the Idaho Power Energy Exchange unnecessary as a price and load reduction tool.

To market the Energy Exchange, Idaho Power's delivery service representatives identified the 35 eligible customers most likely to participate and solicited their participation in this optional program. Representatives from Idaho Power gave formal Energy Exchange presentations to three special contract customers and several large power users. The goal for the Company was to have ten meter points active in the Idaho Power Energy Exchange.

Two companies signed agreements to participate in the Idaho Power Energy Exchange. Between these two customers, there were three service points in Idaho and two in Oregon. These five service points had the combined potential of providing a maximum of approximately 13 MW of load reduction. The level of reduction is an approximation based on historic hourly load levels and the customer's reduction projections.

While marketing this program, Idaho Power found that unlike some of the other utilities that had initiated successful energy exchanges, the characteristics of Idaho Power's customer base make voluntary load reduction for short periods of a few hours per day difficult and usually not economically viable. Many of Idaho Power's large power users are food processors. These companies have spoilage issues, cold storage capacity limitations, inflexible shipping and delivery schedules, and maintenance schedules that prohibit them from participation in this type of program. The Company found that most of the large power users in Idaho Power's service territory do not have any load monitoring equipment, a fact that made accurate load reduction difficult. Several companies required earlier notification of Exchange Events, as well as, reduction of loads for longer periods to allow more time for ramping loads up or down than the design of the Energy Exchange provided. Some companies hesitated to participate because of labor management challenges during periods of load reduction. Others expressed the view that the electric energy component was such a small part of their overall cost of production that compensation for load reduction generally did not make good economic sense.

Idaho Power paid Apogee Interactive $23,500 to design, program, and administer the Idaho Power Energy Exchange for the first year. For this initial fee, Idaho Power could have up ten customers (meter points) active in the Energy Exchange and could have up to ten Exchange Events per customer without additional fees. The contract with Apogee Interactive ended May 1, 2002. The cost to Idaho Power to keep the Idaho Power Energy Exchange in 'warm stand-by' mode until May 1, 2003 would have been $10,000. Warm stand-by would have kept the Idaho Power Energy Exchange website accessible but not interactive. The cost for Idaho Power to activate the Energy Exchange during the contract year would have been $10,000 in additional fees. Considering the results of the first year of the Energy Exchange, Idaho Power did not believe it prudent to renew this contract.

When Idaho Power Company filed its application, the below-normal stream flows in the Snake River and its tributaries, coupled with the volatile wholesale energy market in the western United States, had created a situation where Idaho Power believed it would be cost-effective for the Company to undertake this program. Because of changes in wholesale electricity market conditions, the western price caps, and the composition of Idaho Power's customers, Idaho Power found that the Energy Exchange was not useful method of load reduction.

Idaho Power Company did gain valuable knowledge and experience in administering and managing load reduction programs like the Energy Exchange. If the wholesale electricity market conditions were to change and if the Company deemed it necessary, electric load reduction agreements could be established with individual customers with regulatory approval as has been done in the past. Considering the fact that few customers would be interested in or capable of this type of load reduction agreement, an interactive website would not be essential and the load reduction could be administered with normally available resources.

EXHIBIT No. 224

Case No. IPC-E-06-09

D.READING, ICIP

RECEIVED

BY__________________

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE PETITION OF IDAHO POWER COMPANY FOR MODIFICATION OF THE LOAD GROWTH ADJUSTMENT RATE WITHIN THE POWER COST ADJUSTMENT METHODOLOGY	CASE NO. IPC-E-06-08 IDAHO POWER COMPANY'S RESPONSE TO THE FIRST PRODUCTION REQUEST OF NW ENERGY COALITION TO IDAHO POWER COMPANY

COMES NOW, Idaho Power Company ("Idaho Power" or "the Company") and, in response to the First Production Requests of NW Energy Coalition to Idaho Power Company dated August 8, 2006, herewith submits the following information:

REQUEST FOR PRODUCTION NO. 1:

Please state Idaho Power company's normalized system loads for each year starting with year 1995 through 2005.

RESPONSE TO REQUEST FOR PRODUCTION NO. 1:

Idaho Power company's normalized system loads for 1995 through 2005 in MWh's are as follows:

1995	14656029
1996	15141574
1997	15180588
1998	14758836
1999	15240817
2000	15837958
2001	15759779
2002	14276689
2003	14193837
2004	14536634
2005	14819152

The response to this request was prepared by Gregory W. Said, Manager of Revenue Requirement, Idaho Power Company, in consultation with Barton L. Kline, Senior Attorney, Idaho Power Company.

REQUEST FOR PRODUCTION NO. 4:

Please state Idaho Power Company's total amount of spending on demand-side management ("DSM") programs or initiatives (including payments to the Northwest Energy Efficiency Alliance ("NEEA") for each year starting with year 1995 through 2005.

RESPONSE TO REQUEST FOR PRODUCTION NO. 4:

The following table details Idaho Power Company's total amount of spending on demand-side management ("DSM") programs or initiatives (including payments to the Northwest Energy Efficiency Alliance ("the Alliance")) for each year starting with year 1995 through 2005 as provided in the Company's respective DSM Annual Reports (previously termed Conservation Plan) filed with the Commission.

	Total System (nominal $)
1995	$6,186,558
1996	$4,350,128
1997	$3,189,173
1998	$2,681,668
1999	$2,127,840
2000	$1,609,217
2001	$1,694,314
2002	$2,143,103
2003	$2,482,972
2004	$3,707,280
2005	$6,700,973

Notes:
Expenses are reported on a cash basis.

The response to this request was prepared by Tim Tatum, Senior Analyst, Idaho Power Company, in consultation with Barton L. Kline, Senior Attorney, Idaho Power Company.

EXHIBIT No. 225

Case No. IPC-E-06-09

D.READING, ICIP

REQUEST FOR PRODUCTION NO. 8:

Please state the total amount of estimated energy savings (expressed as average megawatts) Idaho Power Company and its customers have achieved as a result of DSM programs (including any savingsj achieved as a result of NEEA programs) for each year starting with year 1995 through 2005.

RESPONSE TO REQUEST FOR PRODUCTION NO. 8:

The following table details the total amount of estimated energy savings (expressed as average megawatts) Idaho Power Company and its customers have achieved as a result of DSM programs (including any savings achieved as a result of Alliance programs) for each year starting with year 1995 through 2005 as provided in the company's respective DSM Annual Reports (previously termed Conservation Plan) filed with the Commission.

Year	Annual Energy Savings excluding Alliance (Mwa)	Alliance Reported Energy Savings * (Mwa)	Total Annual Energy Savings (Mwa)
1995	4.72		4.72
1996	3.65		3.65
1997	1.94		1.94
1998	1.87		1.87
1999	0.24		0.24
2000	0.02		0.02
2001	0.05		0.05
2002	0.51		0.51
2003	0.67		0.67
2004	0.9	2.36	3.26
005	2.42	2.29**	4.71

Notes:
*Alliance Savings not available prior to 2004. The Alliance savings based on regional load allocation percentage of 6.5%.
**Preliminary estimate from the Alliance, February 24, 2006

The response to this request was prepared by Tim Tatum, Senior Analyst, Idaho Power Company, in consultation with Barton L. Kline, Senior Attorney, Idaho Power Company.

EXHIBIT No. 226

Case No. IPC-E-06-09

D.READING, ICIP

Generation Options for Idaho's Energy Plan

Arne Olson
Energy & Environmental Economics, Inc. (E3)

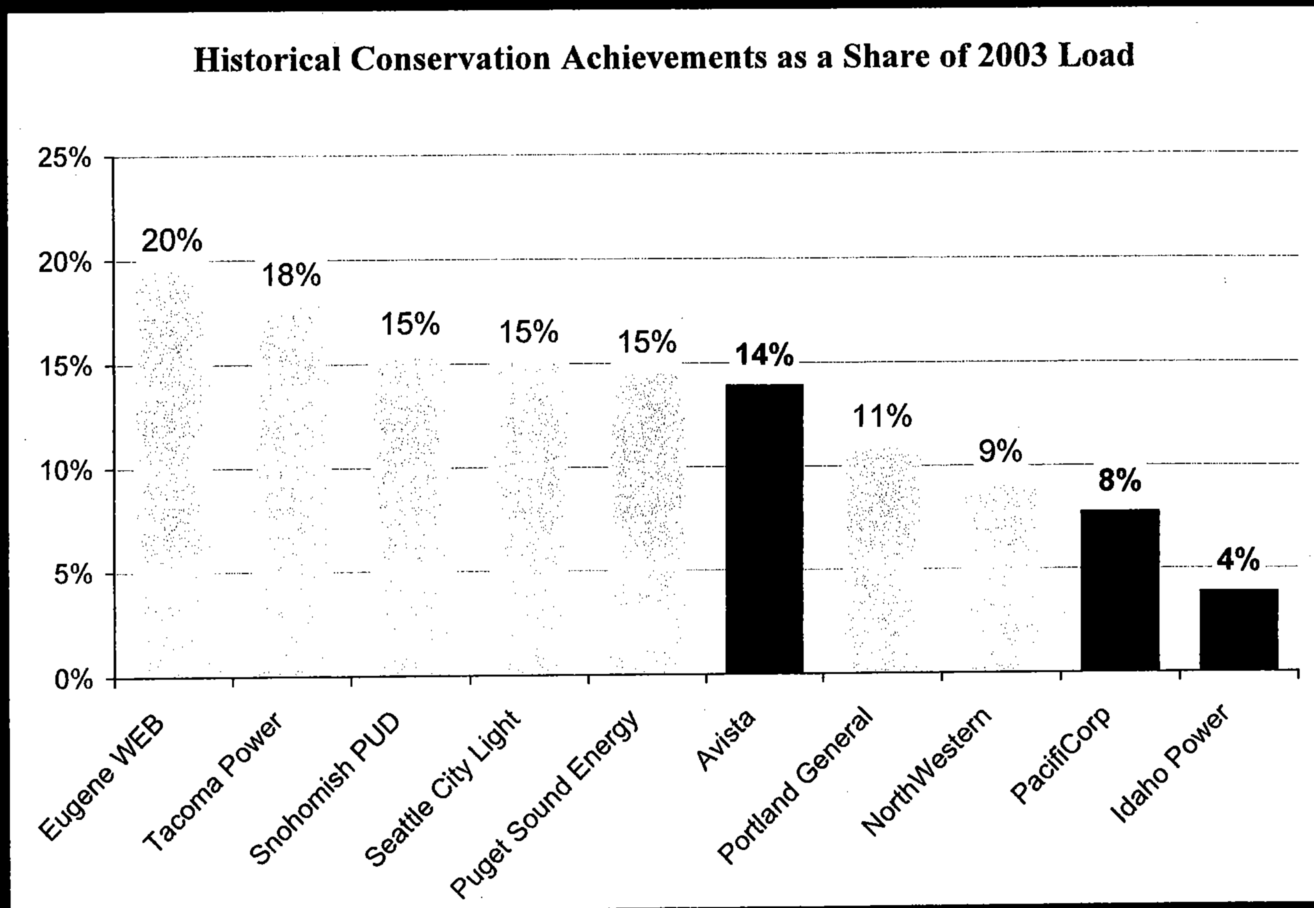
Presented to:

Subcommittee on Generation Resources
Boise, Idaho
August 10, 2006

Energy and Environmental Economics, Inc.

353 Sacramento Street, Suite 1700
San Francisco, CA 94111
Telephone: (415) 391-5100
http://www.ethree.com

Historical Conservation Achievements of Northwest Utilities



Planned Conservation Investments of Idaho Utilities by 2015

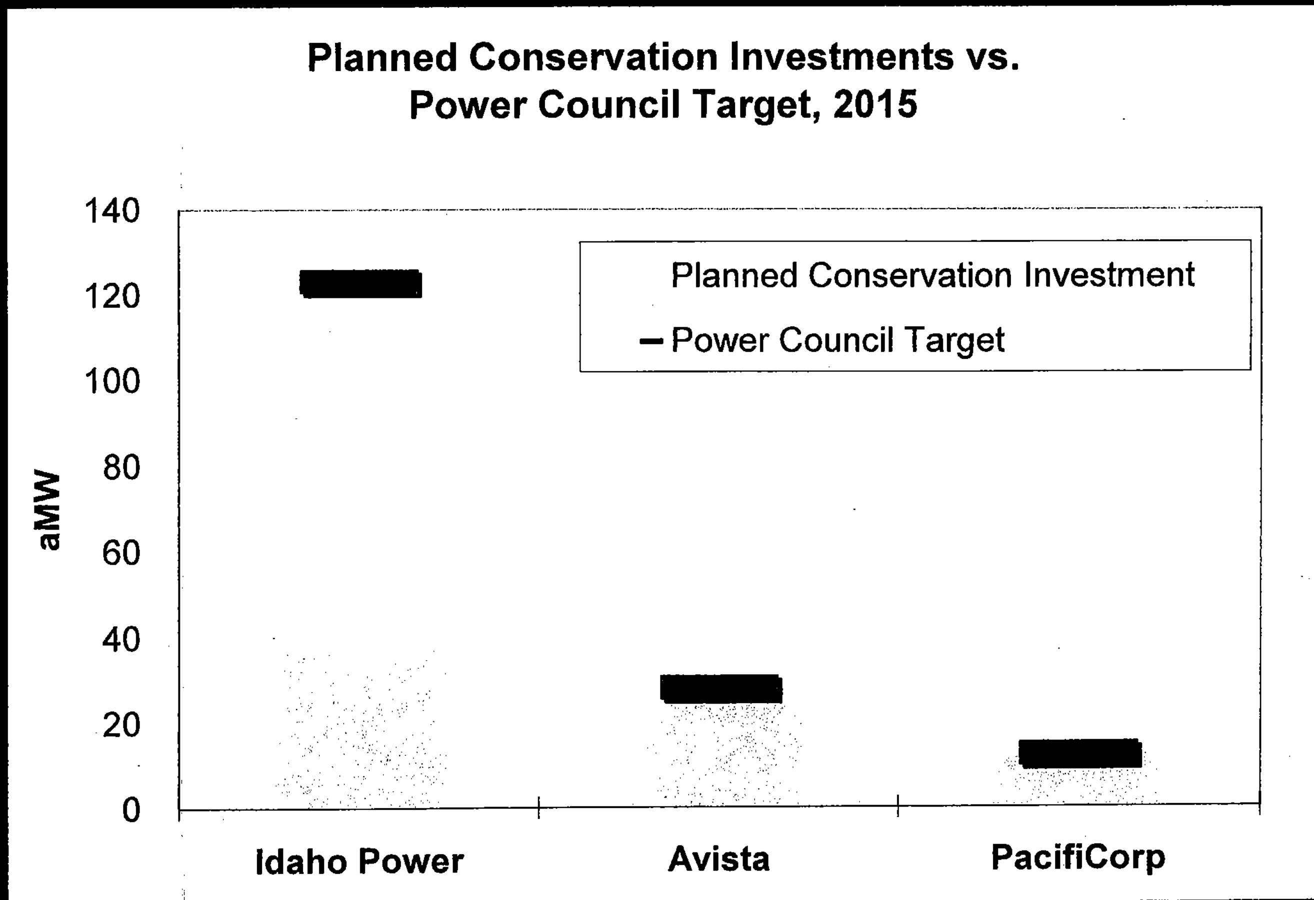


EXHIBIT No. 227

Case No. IPC-E-06-09

D.READING, ICIP

QUANTUM CONSULTING

IDAHO POWER DEMAND-SIDE MANAGEMENT POTENTIAL STUDY

FINAL

Prepared for

Darlene Nemnich
Project Leader
Customer Relations and Research Department
Idaho Power
1221 West Idaho Street
Boise, Idaho 83702

Prepared by

QUANTUM CONSULTING INC.
2001 Addison Street, Suite 300
Berkeley, CA 94704
510-540-7200

with assistance from

KEMA-XENERGY, Inc.

P1992

November 2004

TABLE OF CONTENTS

4. ENERGY EFFICIENCY PEAK DEMAND AND ENERGY SAVINGS POTENTIAL RESULTS

In this section we present summary results of the Idaho Power energy efficiency potential analysis for the residential and commercial sectors. First, economic and technical potential are discussed. Next, we present summary energy efficiency supply curves, which are an alternative method of presenting forecasted potentials. Finally, we present scenario forecasts for achievable energy efficiency potential. Definitions of the different types of energy efficiency potential and methods used to develop them are provided in Section 2 of this report. Section 2 also presents the baseline estimates used in our analyses.

At the outset of this study, the primary focus was on peak demand reduction and the scope was limited to measures with impacts on summer peak. In a later, second phase, the scope was expanded to look at all measures with the potential to provide cost-effective energy savings. Where possible, the figures in this section delineate the peak demand and energy savings associated with the two phases. In cases where there is no distinction, the figures represent the results of the second phase. Because the results of the first phase were provided to the resource-planning group at IPCo, identical graphs based only on the results of the initial phase are provided separately in Appendix G.

4.1 TECHNICAL AND ECONOMIC POTENTIAL

In Exhibits 4-1 and 4-2 we present our overall estimates of total technical and economic potential for peak demand and electrical energy in the residential and commercial sectors in the Idaho Power territory. **Technical potential** represents the sum of all savings achieved if all measures analyzed in this study were implemented in applications where they are deemed applicable and physically feasible. As described in Section 2, **economic potential** is based on efficiency measures that are cost-effective based on the total resource cost (TRC) test, a benefit-cost test used to compare the value of avoided energy production and power plant construction to the costs of energy-efficiency measures and program activities necessary to deliver them. The value of both energy savings and peak demand reductions are incorporated into the TRC test.

Overall and by Sector

If all measures analyzed in this study were implemented where technically feasible, we estimate that overall technical demand savings would be roughly 551 MW, about 33 percent of projected combined residential and commercial peak demand in 2013. If all measures that pass the TRC test were implemented, economic potential savings would be 384 MW, about 23 percent of total residential and commercial demand in 2013. Technical energy savings potential is estimated to be roughly 1,917 GWh, about 21 percent of total residential and commercial energy usage projected in 2013. Economic energy savings are estimated at 1,107 GWh, about 12 percent of base residential and commercial usage. The technical and economic potential estimates are shown by sector and vintage (existing stock versus new construction) in Exhibits 4-3 through 4-5. The largest share of both technical and economic savings is in the residential existing stock.

Exhibit 4-1
Technical and Economic Potential (2013)
Peak Demand Savings—MW

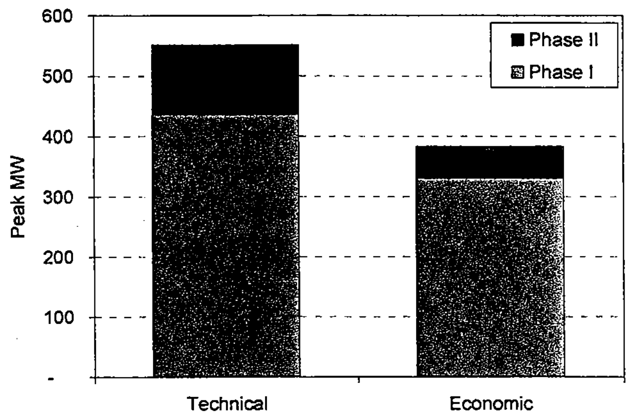


Exhibit 4-2
Technical and Economic Potential (2013)
Energy Savings—GWh per Year

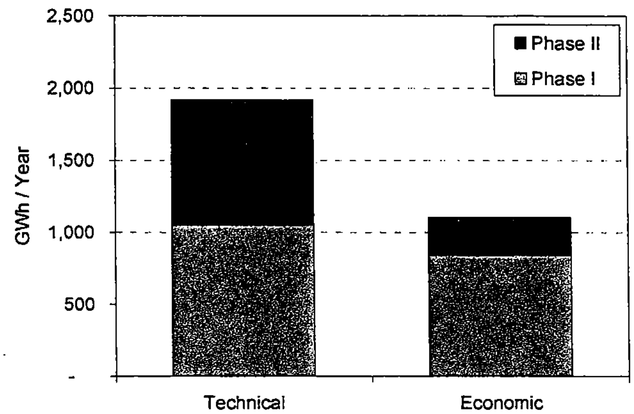


Exhibit 4-3
Technical and Economic Potential by Sector and Vintage, Peak Demand Savings (2013)

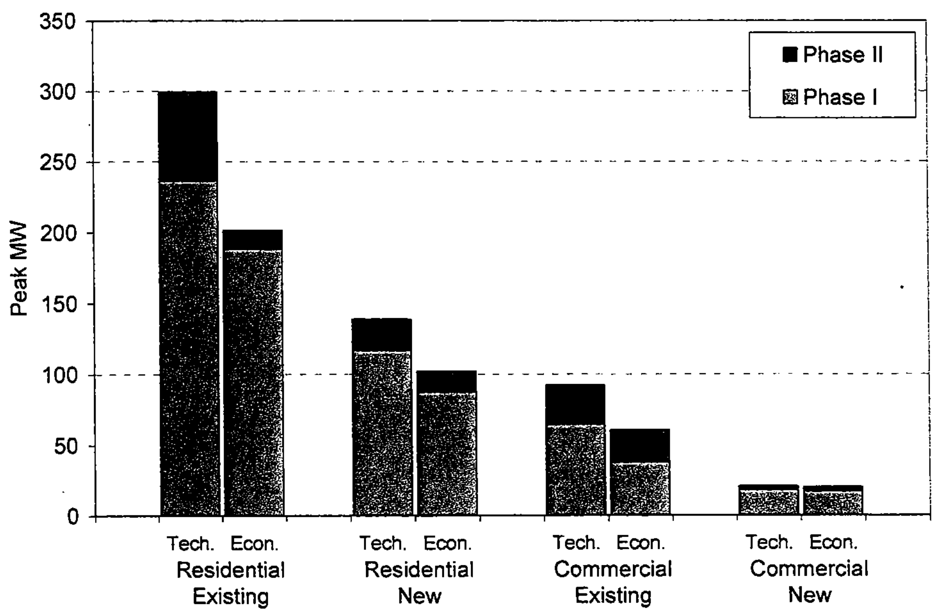


Exhibit 4-4
Technical and Economic Potential by Sector and Vintage, Energy Savings (2013)

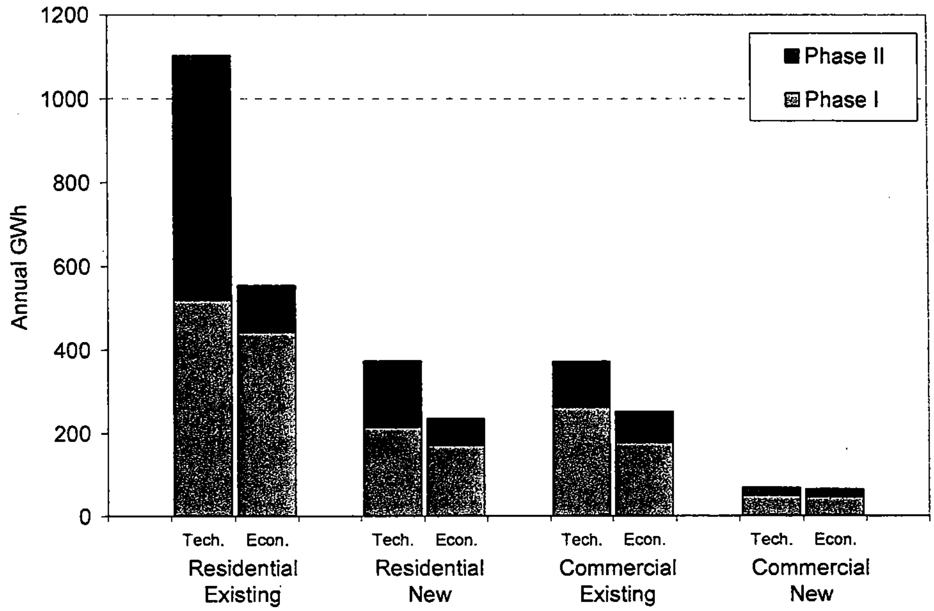


Exhibit 4-5a
Phase II Technical and Economic Potential Estimates

Sector and Vintage	MW		GWh	
	Technical	Economic	Technical	Economic
Residential – Existing	299	201	1,102	554
Residential – New	139	102	373	235
Commercial – Existing	92	60	373	252
Commercial - New	21	20	69	65
Total	551	384	1,917	1,107

Exhibit 4-5b
Phase I Technical and Economic Potential Estimates

	MW		GWh	
Sector and Vintage	Technical	Economic	Technical	Economic
Residential – Existing	237	189	520	444
Residential – New	117	88	216	173
Commercial – Existing	65	38	265	179
Commercial - New	23	22	59	55
Total	442	337	1,060	851

End Use Potential

Residential economic potential is presented by key end use in Exhibit 4-6. Lighting, cooling, and clothes washing dominate economic energy savings, while cooling makes up the vast majority of peak demand impacts. Exhibit 4-7 shows commercial sector economic potential estimates by end use. Lighting is the largest contributor in terms of both energy savings potential and peak demand savings potential, cooling is the second largest contributor to commercial economic peak demand savings.

Potential by Building Type

Exhibit 4-8 displays residential economic potential by building type. Single-family homes account for the vast majority of potential. Commercial sector economic potential is displayed by building type in Exhibit 4-9. The largest contributors to both GWh and peak MW potential are small offices, food stores, retail establishments, hospital/health care facilities, and "miscellaneous" buildings.

4.2 ENERGY EFFICIENCY SUPPLY CURVES

Energy efficiency supply curves for energy and peak demand savings are shown in Exhibits 4-10 and 4-11, respectively. The supply curves show the distribution of measure-level potentials by relative cost. Energy supply curve summary data are presented Exhibits 4-12 through 4-15 for the residential existing, residential new construction, commercial existing and commercial new construction vintages. Note that these values are aggregated across market segments and that individual segment results can vary significantly from the average values shown. In addition, it is important to recognize that cost-effectiveness, as defined by the TRC test, cannot be determined exclusively from these curves because the value of both energy and demand savings must be integrated when comparing to supply side alternatives. Measure-level TRC estimates are provided in Appendix E.

EXHIBIT No. 228

Case No. IPC-E-06-09

D.READING, ICIP

AVISTA Corp.

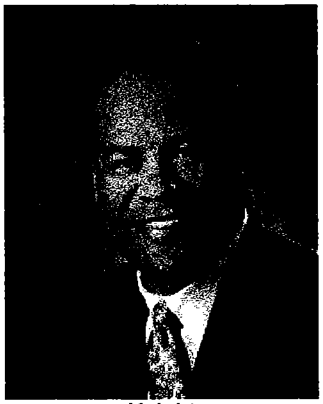
August 2006

Quarterly Review

Welcome to Avista Corp.,
providing energy and energy-related services

Corporate News

Director Jessie Knight steps down from Avista board



Knight

In June, Jessie Knight resigned from Avista Corp.'s board of directors, following accepting a position as an executive officer of Sempra Energy (NYSE: SRE).

"Jessie served on the board for seven years and was a great asset during some difficult times," said Avista Corp. Chairman and Chief Executive Officer Gary Ely. "Although we are sorry to see him go, we wish Jessie the greatest success at Sempra and in all of his future endeavors."

A replacement has not yet been selected for Mr. Knight's seat on Avista's board.

Read more about this.

Investor Update

Q2 2006 and Year-to-Date Earnings on track

For the second quarter of 2006, Avista Corp. reported net income of $13.5 million, or $0.27 per diluted share, a decrease over the same period last year. Year-to-date for the six months ended June 30, 2006, the company posted net income of $45.0 million, or $0.91 per diluted share, an increase of $16.2 million, or $0.32 per diluted share, over results in the same period of 2005.

Ely

"We are on track for a good year in 2006 due to improved year-to-date earnings from Avista Utilities and the continued trend of earnings growth from Advantage IQ," said Avista Chairman and Chief Executive Officer Gary G. Ely.

"We are satisfied with Avista Energy's operations, which are on track for the year as measured on an economic basis. However, its reported results continue to differ from economic results due to the required accounting for certain contracts and assets under management," Ely added.

Improved stream flows and hydro electric generation during the first two

Financial Resources

- **Avista Corp. Q2 2006 Income Statement**
- **Avista Corp.Q2 2006 Balance Sheet**
- **Avista Corp. Q2 2006 Financial and Operating Highlights**
- **Avista Corp. Stock Quote/Chart**
- **Avista Corp. 2005 Summary Annual Report**

Avista Corp.

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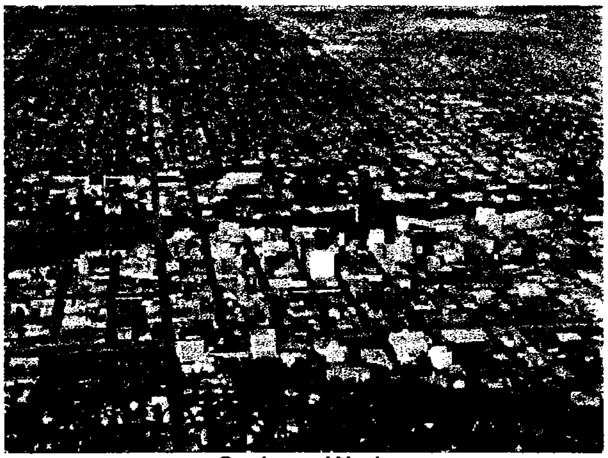
"We believe the modified ERM better balances the interests of the company and our customers," said Scott Morris, president and chief operating officer of Avista Corp. "This will also help reduce the volatility in our earnings that has been caused by variations in the prices for fuel and purchased power, as well as the availability of hydro generation."

Morris

Calls for conservation keep power flowing



Spokane, Wash.

As is proving true throughout the country, this has been a hot summer in Avista Utilities' service territory.

On July 24, after several days of extremely high temperatures in eastern Washington and northern Idaho, Avista's retail native load peaked at 1,642 MW, an all-time high for the utility's summer load. Due to the high loads coupled with some short-term plant outages, unplanned power purchases in the wholesale market were needed. Short-term prices were extremely high, as electrical supplies were stretched across the West due to the record high temperatures and strong demand.

To minimize the amount of unplanned purchases, Avista reached out to customers through personal contact and the media and requested their voluntary conservation of energy on both July 24 and 25. Customers responded quickly and effectively, cutting load by approximately 30 megawatts. The reduction in loads not only contributed to our ability to continue to provide reliable service to our customers; it also reduced the overall cost of providing power during this time period.

If you are not yet a subscriber to this newsletter and would like to receive it via e-mail, please contact Avista News.

This quarterly review contains forward-looking statements, including statements regarding the company's current expectations for future financial performance and cash flows, capital expenditures, the company's current plans or objectives for future operations, future hydroelectric generation projections and other factors, which may affect the company in the future. Such statements are subject to a variety of risks, uncertainties and other factors, most of which are beyond the company's control and many of which could have significant impact on the company's operations, results of operations, financial condition or cash flows and could cause actual results to differ materially from the those anticipated in such statements.

The following are among the important factors that could cause actual results to differ materially from the forward-looking statements: weather conditions, including the effect of precipitation and temperatures on the availability of hydroelectric resources and the effect of temperatures on customer demand; changes in wholesale energy prices that can affect, among other things, cash requirements to purchase electricity natural gas for retail customers and natural gas fuel for electric generation, as well as the market value of derivative assets and liabilities and unrealized gains and losses; volatility and illiquidity in wholesale energy markets, including the availability and prices of purchased energy and demand for energy sales; the effect of state and federal regulatory decisions affecting the ability of the Company to recover its costs and/or earn a reasonable return, including, but not limited to, the disallowance of previously deferred costs; the outcome of pending regulatory and

EXHIBIT No. 229

Case No. IPC-E-06-09

D.READING, ICIP

REQUEST FOR PRODUCTION NO. 38: With regard to the "Cogen and Small Power Forecast (aMW)" referred to above in Request for Production No. 40 [sic 37], please explain fully why the document shows no increase in Cogen and Small Power generation after 2004. Additionally, please explain whether the Company forecasts any increase in Cogen and Small Power generation after 2006 and beyond.

RESPONSE TO REQUEST NO. 38: The Cogen and Small Power Production (CSPP) forecast is revised, at a minimum, annually. Because Idaho Power has no control over the development and operation of CSPP projects, forecasting of the actual energy output and monthly shape of the energy delivery from these facilities is very difficult. In fact, in the case new CSPP resources under contract with Idaho Power but not yet constructed, the actual online dates of these projects tend to vary tremendously from their estimated online dates which makes it virtually impossible to depend on any generation from these projects until such time as they have actually come online and established some monthly generation history. As a result, the Company only includes the estimated output from projects with signed and IPUC-approved agreements in the CSPP forecast at the time the forecast is prepared.

Idaho Power currently has over 200 MW of nameplate rating of new CSPP projects under contract that have not yet been constructed. The majority of these projects are wind projects. Thus, after applying an optimistic capacity factor of 30% to this 200 MW of nameplate rating, the amount of generation anticipated from these resources is approximately 60 MW on an annual average basis.

The majority of these projects estimate online dates in late 2007. Thus, in the current forecast provided in response to Request No. 37, the additional generation is forecasted to appear in calendar year 2008. However, it is important to note that, since Idaho Power has no control over the construction or operation of these or any additional PURPA projects, this forecast will most likely change numerous times prior to these projects coming online and after actual operation history has been established for these projects.

The response to this request was prepared by Randy C. Allphin, CSPP Contract Administrator, Idaho Power Company, in consultation with Monica Moen, Attorney II, Idaho Power Company.

EXHIBIT No. 230

Case No. IPC-E-06-09

D.READING, ICIP

REQUEST FOR PRODUCTION NO. 37: In Idaho Power's Response to Staff's Request No. 81, Idaho Power provided a copy of the Company's 2003 evaluation manual for the peaking resource RFP. Page 29 of that document sets forth a "Cogen and Small Power Forecast (aMW)." Please provide a copy of the Company's current "Cogen and Small Power Forecast (aMW)." If one is not available, please fully explain why, and how the Company's decisions with regard to the 2005 RFP took into account the generation the Company would receive from Cogen and Small Power Producers.

RESPONSE TO REQUEST NO. 37: Please refer to the document attached hereto as "Response to Request for Production No. 37."

The response to this request was prepared by Randy C. Allphin, CSPP Contract Administrator, Idaho Power Company, in consultation with Monica Moen, Attorney II, Idaho Power Company.

IDAHO POWER COMPANY

CASE NO. IPC-E-06-9

THIRD PRODUCTION REQUEST

OF INDUSTRIAL CUSTOMERS

RESPONSE TO

REQUEST NO. 37

2007	Mwh	Average Mw	Energy Amount	Capacity Amount	Total
Jan	37,188	50	$2,022,670	$234,594	$2,257,264
Feb	34,710	52	$1,878,023	$234,594	$2,112,617
Mar	40,540	54	$1,650,652	$234,594	$1,885,245
Apr	56,896	79	$2,389,626	$234,594	$2,624,220
May	87,107	117	$3,690,706	$234,594	$3,925,300
Jun	93,810	130	$6,095,225	$234,594	$6,329,818
Jul	98,971	133	$6,530,862	$234,594	$6,765,456
Aug	93,440	126	$6,037,698	$234,594	$6,272,292
Sep	76,666	106	$4,473,274	$234,594	$4,707,867
Oct	56,995	77	$2,918,452	$234,594	$3,153,046
Nov	40,255	56	$2,200,307	$234,594	$2,434,900
Dec	42,526	57	$2,427,753	$234,594	$2,662,347
	759,104	87	$42,315,248	$2,815,124	$45,130,372

2008	Mwh	Average Mw	Energy Amount	Capacity Amount	Total
Jan	56,228	76	$3,060,370	$234,594	$3,294,964
Feb	56,823	85	$3,085,824	$234,594	$3,320,417
Mar	71,540	96	$2,913,530	$234,594	$3,148,123
Apr	85,385	119	$3,544,524	$234,594	$3,779,117
May	126,251	170	$5,282,266	$234,594	$5,516,859
Jun	141,599	197	$8,715,421	$234,594	$8,950,014
Jul	142,698	192	$9,401,529	$234,594	$9,636,123
Aug	138,234	186	$8,965,477	$234,594	$9,200,071
Sep	128,132	178	$7,288,582	$234,594	$7,523,176
Oct	113,375	152	$5,999,479	$234,594	$6,234,073
Nov	93,911	130	$5,713,305	$234,594	$5,947,899
Dec	101,396	136	$6,290,431	$234,594	$6,525,024
	1,255,572	143	$70,260,738	$2,815,124	$73,075,862

2009	Mwh	Average Mw	Energy Amount	Capacity Amount	Total
Jan	89,708	121	$4,951,426	$234,594	$5,186,020
Feb	91,155	136	$5,034,427	$234,594	$5,269,021
Mar	95,727	129	$3,948,796	$234,594	$4,183,390
Apr	104,773	146	$4,379,039	$234,594	$4,613,633
May	132,437	178	$5,584,147	$234,594	$5,818,741
Jun	147,081	204	$9,089,567	$234,594	$9,324,161
Jul	145,441	195	$9,650,408	$234,594	$9,885,002
Aug	137,900	185	$9,036,560	$234,594	$9,271,154
Sep	128,132	178	$7,367,205	$234,594	$7,601,799
Oct	113,375	152	$6,084,350	$234,594	$6,318,944
Nov	93,911	130	$5,804,987	$234,594	$6,039,581
Dec	101,396	136	$6,392,131	$234,594	$6,626,724
	1,381,036	158	$77,323,045	$2,815,124	$80,138,169

Contr ministration
Randy 8-29-2006 CSPP forecast e-mail via

2010	Mwh	Average Mw	Energy Amount	Capacity Amount	Total
Jan	89,708	121	$5,023,204	$234,594	$5,257,798
Feb	91,155	136	$5,111,643	$234,594	$5,346,236
Mar	95,727	129	$4,004,896	$234,594	$4,239,489
Apr	104,773	146	$4,428,970	$234,594	$4,663,563
May	132,437	178	$5,636,118	$234,594	$5,870,712
Jun	147,081	204	$9,170,518	$234,594	$9,405,112
Jul	140,966	189	$9,495,409	$234,594	$9,730,003
Aug	133,814	180	$8,902,009	$234,594	$9,136,603
Sep	123,292	171	$7,209,112	$234,594	$7,443,706
Oct	111,779	150	$6,108,687	$234,594	$6,343,281
Nov	92,252	128	$5,837,744	$234,594	$6,072,337
Dec	99,568	134	$6,428,649	$234,594	$6,663,242
	1,362,552	156	$77,356,958	$2,815,124	$80,172,082

2011	Mwh	Average Mw	Energy Amount	Capacity Amount	Total
Jan	88,243	119	$5,042,496	$234,594	$5,277,090
Feb	89,689	133	$5,137,674	$234,594	$5,372,268
Mar	94,183	127	$4,021,500	$234,594	$4,256,094
Apr	102,349	142	$4,408,405	$234,594	$4,642,999
May	127,750	172	$5,547,030	$234,594	$5,781,624
Jun	141,489	197	$8,973,722	$234,594	$9,208,316
Jul	138,996	187	$9,494,975	$234,594	$9,729,569
Aug	131,694	177	$8,894,193	$234,594	$9,128,786
Sep	123,292	171	$7,291,503	$234,594	$7,526,096
Oct	111,779	150	$6,197,630	$234,594	$6,432,223
Nov	92,252	128	$5,934,123	$234,594	$6,168,717
Dec	99,568	134	$6,535,563	$234,594	$6,770,156
	1,341,284	153	$77,478,814	$2,815,124	$80,293,937

EXHIBIT No. 231

Case No. IPC-E-06-09

D.READING, ICIP

REQUEST FOR PRODUCTION NO. 18: Should the Commission deny Idaho Power's request for a certificate of public convenience and necessity, what supply or demand reduction alternative options would the Company turn to in the summer of 2007 [sic][2008]?

RESPONSE TO REQUEST NO. 18: Please refer to the Response to Request No. 13. If the Commission denies Idaho Power's request for a certificate of public convenience and necessity, Idaho Power would most likely consider several alternatives to meet peak-hour loads during the summer of 2008. These alternatives include: (1) additional firm market purchases and the associated transmission necessary to deliver the energy to the east side of Idaho Power's system, (2) transmission system expansions to increase import capacity, (3) expansion of the Irrigation Peak Rewards program (which is already being investigated), (4) developing advertising messages that ask consumers to reduce their peak-hour consumption, and (5) utilizing diesel or other temporary gensets.

The response to this request was prepared by Karl E. Bokenkamp, General Manager Power Supply Planning and Operations, Idaho Power Company, in consultation with Barton L. Kline, Senior Attorney, Idaho Power Company.

EXHIBIT No. 232

Case No. IPC-E-06-09

D.READING, ICIP

REQUEST FOR PRODUCTION NO. 40: In response to ICIP Request for Production No. 18, Idaho Power describes five alternatives for meeting peak demand that it would consider if the Commission denies its request for a certificate of public convenience and necessity for the Evander Andrews plant. Please describe what efforts the Company has made to determine the costs of those alternatives and any estimates the Company has developed of the costs for implementing these alternatives instead of constructing the Evander Andrews plant.

RESPONSE TO REQUEST NO. 40: The Company has not performed a detailed analysis of the costs associated with the five alternatives described in ICIP Request for Production No. 18. Preliminary estimates are available for a couple of the alternatives.

Alternative 1 – Additional firm east side purchases. Idaho Power has priced, but has not executed, any additional firm east side purchases for heavy load hours in July 2007. On September 5, 2006, the Mid-C to Four Corners price spread for firm heavy load energy was $16 to $17/MWh. The higher Four Corners price is representative of the premium Idaho Power may have to pay for an east side purchase. In addition to the premium relative to Mid-C pricing, the cost to purchase energy on Idaho Power's east side may require an additional expenditure of $5 - $7 to compensate for the cost of transmission between Four Corners and Idaho Power's east side interconnections.

Alternative 2 – Increase transmission system import capacity. Several alternatives to increase import capacity were investigated in the 2006 IRP. Pages 57 through 62 of the Draft 2006 IRP (IRPAC Draft) discuss these transmission projects.

Preliminary cost estimates (prepared by Power Engineers) range from $10.8 million to reconductor the Lolo to Oxbow line to $282 million for the Bridger to Midpoint 500 kV upgrade.

These upgrades were not originally envisioned as alternatives to replace the new Evander Andrews combustion turbine. However, if the certificate of public convenience and necessity for the Evander Andrews plant is denied, the projects identified in the 2006 IRP are the type of longer-term transmission upgrades that Idaho Power would consider to increase import capability. Idaho Power has submitted long-term firm transmission requests to NorthWestern Energy, BPA, Avista, PacifiCorp and Idaho Power. These requests establish a position in the transmission providers' queue and initiate the process of determining system impacts and preparation of more detailed cost estimates. However, with the exception of the Lolo to Oxbow reconductoring project, Idaho Power does not consider these transmission upgrades a near-term alternative due to construction lead-time.

Alternative 3 – Expand irrigation peak rewards program. Idaho Power is currently planning changes to the Irrigation Peak Rewards Program. The Company anticipates filing those proposed changes with the IPUC later this month. The proposed program modifications are expected to result in an additional 4.5 MW (including losses) of cost-effective load reduction during the Company's summer peak. A revised Demand Credit structure and a reduced horsepower limit are the modifications largely expected to drive the additional load reduction. Under the revised Demand Credit structure, it is expected that approximately 13% of the customers currently participating with a one day Interruption Option will shift to a two or three day Interruption Option.

The revised Demand Credit structure and the reduced horsepower limit are also expected to improve customer satisfaction among program participants. In the Company's survey of 2005 program participants, the most frequently recommended improvement to the program was an increase to the Demand Credits. Improvements in customer satisfaction is also anticipated among those customers with cumulative horsepower between 75 and 99 that have wanted to participate in the program in past years, but were not eligible.

In addition, the Company is considering a shift in the interruption period from 4:00 p.m. to 8:00 p.m. to 3:00 p.m. to 7:00 p.m. The Company is currently surveying participants concerning their preferences with respect to timing of daily interruption periods. Changing the interruption period may increase program participant satisfaction and possibly increase program participation. It is anticipated that these changes will increase spending on this program by approximately $300,000 per year.

Alternative 4 – Advertising messages. No efforts to determine costs.

Alternative 5 – Add temporary gensets. No efforts to determine costs.

The response to this request was prepared by Karl E. Bokenkamp, General Manager Power Supply Operations and Planning, Idaho Power Company, in consultation with Monica Moen, Attorney II, Idaho Power Company.

EXHIBIT No. 233

Case No. IPC-E-06-09

D.READING, ICIP

Final March 30, 2005

IDAHO POWER
An IDACORP Company

Idaho Power Company
1221 West Idaho Street
Boise, Idaho 83702

REQUEST FOR PROPOSALS

Peaking Resource

RFP Issue Date—March 30, 2005

Pre-Bid Conference—April 21, 2005
Mountain Home, Idaho

Notice of Intent Due—May 5, 2005

Proposals Due—June 2, 2005

RFP Website
www.idahopower.com/aboutus/business/rfp/

Table of Contents

1.0 Scope of Request

Idaho Power Company (IPC) is seeking to acquire peaking electric generating resources on a turnkey basis to expand its generation portfolio. IPC issues this Request for Proposals (RFP) to solicit and screen, for subsequent contract negotiations, competitive proposals that will offer exceptional value to IPC and its customers. By responding, Respondents are bound by the terms and conditions of this RFP. IPC will not accept proposals from affiliates or subsidiaries of IDACORP.

Idaho Power Company identified a need for peaking resource electric generation in the *Idaho Power Company 2004 Integrated Resource Plan* (IRP). Specifically, the 2004 IRP indicated that Idaho Power Company would issue an RFP for 88 MW of peaking resource. Summary details of this RFP are:

PRODUCT
A turnkey electric generation resource located within Idaho Power Company's service territory to meet peak energy demands. Upon its completion, legal title of the generating resource will be conveyed to Idaho Power Company. Power purchase agreements where legal title of the generating facilities is not conveyed will not be considered in this RFP.

QUANTITY
Idaho Power Company anticipates acquiring 88 MW of delivered capacity under summer conditions (90°F; 20% relative humidity) at the elevation of the site identified in the proposal. Based on present market conditions of combustion turbines, IPC will consider acquiring resources from 80 MW to 200 MW.

TERM
Provisional Acceptance of the peaking resource must commence no later than April 1, 2007.

The primary need for this resource is to provide electricity during peak energy requirements for the Treasure Valley load center. Idaho Power Company invites Respondents to offer proposals to locate turnkey generating facilities in the locations described below.

Alternative I—Evander Andrews Power Complex

Idaho Power Company owns and operates the Evander Andrews Power Complex located at Mountain Home, Idaho. The power plant has two simple cycle Siemens Westinghouse W251B12A natural gas combustion turbines located on a 40-acre site. These turbines have a nominal rating of 42 MW each at 90°F and 20% relative humidity at an elevation of 3,112 feet above sea level. The power plant consists of an existing control room and warehouse. Expansion of the existing control room will be required and is the responsibility of the Respondent. Any expansion of the warehouse will be IPC responsibility. Specific site information is included in Section 6.0.

EXHIBIT No. 234

Case No. IPC-E-06-09

D.READING, ICIP

REQUEST FOR PRODUCTION NO. 41: Please explain what assumptions the Company is making for the future regarding the Conservation Reserve Enhancement Program (CREP program), through which farmlands will be set aside, and irrigation pumps turned off. Specifically, please describe any assumptions the Company is making regarding decreased peak power requirements as compared to what they would be without the CREP program. Please explain whether these assumptions affected the Company's decisions with regard to the 2005 RFP or [the] Evander Andrews power plant.

RESPONSE TO REQUEST NO. 41: For planning purposes, Idaho Power has not incorporated any specific assumptions in the 2006 IRP regarding the Conservation Reserve Enhancement Program (CREP). On January 9, 2006, Idaho Power announced that it selected a Siemens Power Generation, Inc. proposal to build a 170-megawatt combustion turbine at the utility's Evander Andrews Power Complex north of Mountain Home, Idaho. CREP was announced four months later in May of 2006. The CREP announcement had no effect on the Company's decision regarding the 2005 RFP or the Evander Andrews plant.

In a more recent forecast, Idaho Power has incorporated an annual energy reduction over the next 15 years (2007 through 2021) of approximately 4% because of CREP.

The response to this request was prepared by Karl E. Bokenkamp, General Manager Power Supply Operations and Planning, Idaho Power Company, in consultation with Monica Moen, Attorney II, Idaho Power Company.

EXHIBIT No. 235

Case No. IPC-E-06-09

D.READING, ICIP

REQUEST FOR PRODUCTION NO. 31: In response to ICIP's Production Request No. 1, Idaho Power stated,

> *Given the competitiveness of the pricing in the Bennett Mountain RFP, Idaho Power was able to acquire the incremental 85 MW of capacity (173 MW-88 MW = 85 MW) at an extremely competitive price – providing additional generation at minimal cost while improving reliability for customers.*

Please explain how the "additional generation" acquired, above the 88 MW called for in the 2004 IRP, will change IPC's projected need for future resources as set forth in the 2004 IRP? For example, will the additional generation acquired obviate the need for any specific RFPs that were called for in the 2004 IRP?

RESPONSE TO REQUEST NO. 31: The additional peaking capacity acquired above the 88 MW called for in the 2004 IRP will allow Idaho Power to defer the timing of future resources required to serve peak-hour loads. Although Idaho Power does not typically assign or correlate changes in its resource plan to specific changes in inputs such as load forecast, PURPA generation forecast, Snake River base flows, or resource additions (or losses), the summation of these types of changes are considered in total in the 2006 IRP.

The summation of changes considered in the 2006 IRP, including the 85 MW of additional peaking capacity provided by the larger Evander Andrews combustion turbine, have allowed several of the resources selected in the 2004 IRP to be deferred. First, the 100 MW geothermal resource originally planned to be online in 2008 in the 2004 IRP has been reduced to 50 MW and the online date deferred until 2009. Second, the 62 MW combustion turbine/distributed generation/market purchase resource originally planned to be online in 2010 in the 2004 IRP has been eliminated altogether, although market purchases are still anticipated in the 2006 IRP. Finally, the 12 MW of CHP resources originally planned to be online in 2007 in the 2004 IRP have been deferred until 2010.

The response to this request was prepared by Karl E. Bokenkamp, General Manager Power Supply Operations and Planning, Idaho Power Company, in consultation with Monica Moen, Attorney II, Idaho Power Company.

EXHIBIT No. 237

Case No. IPC-E-06-09

D.READING, ICIP

REQUEST NO. 72: Please elaborate on the highlighted portion of the following statement from page 17, lines 2-6 of Said's direct testimony: "Although the transmission system will require additional investment in order to integrate the Project, those improvements will provide capacity during all seasons and improve reliability of the Company's transmission system." Quantify, if possible, seasonal increases in transmission capacity and improvements in reliability.

RESPONSE TO REQUEST NO. 72:

The third unit at Evander Andrews is expected to run, for the most part, during the summer and winter peak periods of low-hydro years. The additional transmission capacity associated with the required transmission improvements will exist during all hours of all seasons. During those hours that the third unit at Evander Andrews is not running, the additional transmission capacity is available for other uses and their associated benefits.

Presently there are three 230 kV transmission lines making up the Midpoint West transmission system and they all terminate in the vicinity of Boise Bench substation. The addition of the transmission improvements associated with the Evander Andrews project will create a fourth 230 kV transmission line from the Mountain Home area to the Boise area. The addition of a fourth 230 kV line will increase the redundancy and resulting reliability of the transmission system. Further reliability improvements are gained by terminating the new line at Mora Substation; a remote location other than Boise Bench.

The response to this request was prepared by Roger Grim, Engineer, System Planning, Idaho Power Company, in consultation with Barton L. Kline, Senior Attorney, Idaho Power Company.

DATED at Boise, Idaho, this 6th day of July 2006.

BARTON L. KLINE
Attorney for Idaho Power Company

EXHIBIT No. 238

Case No. IPC-E-06-09

D.READING, ICIP

REQUEST NO. 91: Please explain in detail the transmission improvements that "will provide capacity during all seasons and improve the reliability of the Company's transmission system." Please quantify as accurately as possible the benefits of increased transmission capacity and of improved reliability. If these attributes cannot be quantified, please explain why.

RESPONSE TO REQUEST NO. 91: The proposed transmission improvements would be constructed to accommodate the transmission requirements of the new peaking facility. However, these improvements would also have a positive impact on the Company's transmission system generally. Presently, three 230kV transmission lines comprise the Midpoint West transmission system. All three of these lines terminate in the vicinity of the Boise Bench substation. The addition of the transmission improvements required for the Evander Andrews power plant project would create a fourth 230 kV transmission line from the Mountain Home area to the Boise load center. This additional line would increase redundancy and result in increased transmission system reliability. Furthermore, the presence of this new transmission line would make it feasible to add a 230/138 kV transformer in the Mountain Home area and, thereby, improve local area reliability. System reliability is enhanced by terminating the new fourth line at the Mora Substation, a location remote from the Boise Bench substation.

Feasibility Studies for generator interconnections do not attempt to determine whether excess capacity exists on the transmission system. However, the Company's impression from performing the Feasibility Study for the interconnection required by the proposed Evander Andrews power plant is that little excess transmission capacity exists when the new facility would be in full operation.

The response to this request was prepared by Roger Grim, System Planning Engineer, Idaho Power Company, in consultation with Monica B. Moen, Attorney II, Idaho Power Company.

EXHIBIT No. 239

Case No. IPC-E-06-09

D.READING, ICIP

REQUEST FOR PRODUCTION NO. 43: Please provide any long-term transmission planning documents the Company has developed that support any claim by the Company that it was planning on building any of the transmission facilities that will be required to bring the proposed Evander Andrews plant output to load regardless of whether the Evander Andrews plant was built.

RESPONSE TO REQUEST NO. 43: Idaho Power has made no claim that it was planning on building any of the transmission facilities that will be required to bring the proposed Evander Andrews plant output to load regardless of whether the Evander Andrews plant was built. The transmission facilities are required as a result of the proposal to construct an additional peaking resource at the Evander Andrews Power Complex. Without that proposed new facility, the associated transmission facilities to accommodate that project would not be constructed. As a result, Idaho Power has no documents supporting that claim.

The response to this request was prepared by Roger Grim, System Planning Engineer, Idaho Power Company, in consultation with Monica Moen, Attorney II, Idaho Power Company.

EXHIBIT No. 242

Case No. IPC-E-06-09

D. READING, ICIP

Peak Load Condition
Monday, July 24, 2006

Commission Meeting
August 1, 2006

Facts

- Monday, July 24th was the last day of a four day heat wave with temperatures 15 degrees above normal
- PUD reached all-time summer peak load of 845 MW, previous summer peak of 799MW set in 2005
- Northwest Power Pool, which includes British Columbia and Alberta reported a peak of 54,602 MW (winter peak is 58,000 MW, established in December 1998)
- Puget Sound Energy hit an all-time summer peak of 3,175 MW as did PGE, Pacific & Avista

The Western Region

- Record breaking heat wave saw utilities throughout the West set new peak loads
- California peak load was 50,200 MW up 1,164 MW over previous peak set July 2005
- Cal-ISO did not expect to see 50,000 MW on the grid until 2011
- Utilities throughout west struggled to meet demand. Northwest exporting 6,000 MW to California during day
- The Power Pool of Alberta lost 800 MW of resources in the morning and a 740 MW Colstrip unit unexpectedly went offline also

Western Grid Alerts

- The Cal-ISO declared a Stage 1 Alert at 10:00 am followed by a Stage 2 Alert from 1 to 6 pm
- At Stage 2, customers with interruptible contracts are curtailed, voluntary curtailment is requested for all customers because operating reserves are below 5%
- Alberta Power Pool declared a Stage 2 Alert at 10 am and entered a Stage 3 condition at 2:30 pm and actually disconnected from the Western Grid in an effort to isolate itself and prevent problems from cascading to the rest of the west

Power Markets

- Volatile power market prices spiraled up to the price cap of $400 established by FERC
- In February 2006, FERC raised the price cap from $250 to $400
- There were trades made above the price cap in the vicinity of $500 to $600 by a few entities including two northwest public utilities

What Took Place

- PUD entered day with enough resource to cover forecasted peak demand of 785MW
- 35MW transaction cut to PUD when Colstrip went offline
- Kimberly Clark experienced problems with boiler and reduced output by 7MW

Into Action

- Team assembled first thing Monday morning to strategize
- Calls placed to CEO's, power managers and public relations at Puget Sound Energy and Seattle City Light resulting in a joint press release asking customers region wide to reduce their consumption and joint calls to BPA for relief
- PUD Account Reps placed calls to major customers resulting in 10MW of relief both in form of reduced loads and self-generation

In Action

- PUD exercised SMUD contract option to curtail deliveries during peak emergencies by reducing by 17 MW
- Efforts resulted in BPA releasing more water making another 10 MW available through our Slice contract
- PUD Jackson staff uniquely managed system to temporarily increase the project output by 10MW above normal
- Seattle City Light brought a block of power into service for PUD and granted first rights to any additional power they might bring to market

Summary

- PUD Staff faced unique challenge and developed a multi-faceted strategy to help us through a difficult time
- Net cost of power purchased for entire day above our normal contract purchases was $245,000
- Puget Sound Energy, Seattle City Light and BPA worked together with us
- Our customers went to extraordinary effort to help us in reductions in consumption and adding their back-up generation
- PUD has purchased an additional block of 25MW of capacity for August
- NWPCC will hold regional meeting August 23rd to review this event with northwest utilities
- With 6,000 MW being exported to California and a number of wind projects in northwest idle because of no wind, concerns have risen regarding region load/resource model assumptions and wind integration