IDAHO POWER
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2006 Integrated Resource Plan

Revised October 12, 2006

2006 Integrated Resource Plan

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Acknowledgement

Resource planning is a continuous process that Idaho Power Company constantly works to improve. Idaho Power prepares and publishes a resource plan every two years and expects the experience gained over the next few years will lead to modifications in the 20-year resource plan presented in this document. Idaho Power invited outside participation to help develop both the 2004 and 2006 Integrated Resource Plans.

Idaho Power values the knowledgeable input, comments, and discussion provided by the Integrated Resource Plan Advisory Council and the comments provided by other concerned citizens and customers. Idaho Power looks forward to continuing the resource planning process with its customers and other interested parties.

You can learn more about Idaho Power's resource planning process at www.idahopower.com.

Safe Harbor Statement

This document may contain forward-looking statements, and it is important to note that the future results could differ materially from those discussed. A full discussion of the factors that could cause future results to differ materially can be found in our filings with the Securities and Exchange Commission.

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GLOSSARY OF TERMS

A/C – Air Conditioning

AIR – Additional Information Request

Alliance – Northwest Energy Efficiency Alliance

aMW – Average Megawatt

BOR – Bureau of Reclamation

BPA – Bonneville Power Administration

C&RD – Conservation and Renewable Discount

CAMR – Clean Air Mercury Rule

CCCT – Combined-Cycle Combustion Turbine

CDD – Cooling Degree-Days

CFB – Circulating Fluidized Bed

CFL – Compact Fluorescent Light

CHP – Combined Heat and Power

CO_2 – Carbon Dioxide

CRC – Conservation Rate Credit

CSPP – Cogeneration and Small Power Producers

CT – Combustion Turbine

DOE – U.S. Department of Energy

DG – Distributed Generation

DSM – Demand-Side Management

EA – Environmental Assessment

EEAG – Energy Efficiency Advisory Group

EIA – Energy Information Administration

EIS – Environmental Impact Statement

ESA – Endangered Species Act

FCRPS – Federal Columbia River Power System

FERC – Federal Energy Regulatory Commission

GDD – Growing Degree-Days

HDD – Heating Degree-Days

IDWR – Idaho Department of Water Resources

IGCC – Integrated Gasification Combined Cycle

INL – Idaho National Laboratory

IOU – Investor-Owned Utility

IPC – Idaho Power Company

IPUC – Idaho Public Utilities Commission

IRP – Integrated Resource Plan

IRPAC – Integrated Resource Plan Advisory Council

kV – Kilovolt

kW – Kilowatt

kWh – Kilowatt Hour

LIWA – Low Income Weatherization Assistance

MAF – Million Acre Feet

MMBTU – Million British Thermal Units

MW – Megawatt

MWh – Megawatt Hour

NEPA – National Environmental Policy Act

NWPCC – Northwest Power and Conservation Council

NO_x – Nitrogen Oxides

OPUC – Oregon Public Utility Commission

PCA – Power Cost Adjustment

PM&E – Protection, Mitigation, and Enhancement

PPA – Power Purchase Agreement

PTC – Production Tax Credit

PUC – Public Utility Commission

PURPA – Public Utility Regulatory Policies Act of 1978

PV – Present Value

QF – Qualifying Facility

REC – Renewable Energy Credit

Rider – Energy Efficiency Rider

RFP – Request for Proposal

RPS – Renewable Portfolio Standard

RTO – Regional Transmission Organization

SO_2 – Sulfur Dioxide

SCCT – Simple-Cycle Combustion Turbine

WACC – Weighted Average Cost of Capital

WECC – Western Electricity Coordinating Council

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 88 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 1,089 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 88 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 power supply costs. The risk management policy is primarily aimed at managing short-term market purchases and hedging strategies with a typical time horizon of 18 months or less. The risk management policy is intended to supplement the existing IRP process.

Whereas the IRP is the forum for making long-term resource decisions, the risk management policy addresses short-term resource decisions that arise as resources, loads, costs of service, market conditions, and weather vary. The Risk Management Committee oversees both the implementation of the risk management policy and the IRP to ensure the planning process is consistent and coordinated.

Idaho Power intends to commit to, or acquire, a variety of resource types including renewable, thermal, and combined heat and power (CHP) resources, demand-side programs, and transmission resources early in the planning period. If any of the selected resources differ from the expected levels of production or reliability, Idaho Power may need to adjust the resource proportions in later resource plans. Should market or policy conditions change dramatically, the customers of Idaho Power will have the protection of a diverse resource portfolio.

Near-Term Action Plan

Customer growth is the primary driving force behind Idaho Power's need for additional resources. Population growth throughout southern Idaho—specifically in the Treasure Valley—requires additional resources to meet both instantaneous peak and sustained energy needs. Idaho Power's data, projections, and analyses show that a blended, diversified portfolio of resources and full utilization of its import capability during peak-load hours is the most cost-effective, least-risk, and environmentally responsible method to address the increasing energy needs of its customers.

Idaho Power has selected a balanced portfolio which adds renewable resources, demand-side measures, transmission resources, and thermal generation to meet the projected electric demands over the next 20 years. The 2006 IRP identifies the following specific actions to be taken by Idaho Power prior to the next IRP in 2008:

September 2006: 2006 Integrated Resource Plan filed with the Idaho and Oregon Public Utility Commissions

Fall 2006

1. Conclude 100 MW wind RFP issued in response to the 2004 IRP

2. Notify short-listed bidders in 100 MW geothermal RFP issued in response to the 2004 IRP

3. Initiate McNary–Boise transmission upgrade process

4. Develop implementation plans for new DSM programs with guidance from the Energy Efficiency Advisory Group (EEAG)

5. Continue coal-fired resource evaluation with Avista and consider expansion opportunities at Idaho Power's existing projects (Jim Bridger, Boardman, and Valmy)

6. Investigate opportunities to increase participation in the highly successful Irrigation Peak Rewards DSM program

7. Complete the wind integration study

8. Evaluate the Energy Efficiency Rider (Rider) level to fund DSM program expansion

2007

1. Finalize DSM implementation plans and budgets with guidance from the EEAG
2. Conclude 100 MW geothermal RFP
3. Assess CHP development in progress via the PURPA process—consider issuing RFP for 50 MW CHP depending on level of PURPA development
4. Identify leading candidate site(s) for coal-fired resource addition and begin permitting activities
5. Continue study of 225 MW McNary–Boise transmission upgrade
6. Bring 100 MW of wind on-line
7. Evaluate/initiate DSM programs
8. Select coal-fired resource, finalize contracts, begin design, procurement, and pre-construction activities

2008

1. Make final commitment to 225 MW McNary–Boise transmission upgrade
2. Complete 250 MW Borah–West transmission upgrade
3. Bring 170 MW Danskin expansion on-line
4. Evaluate/initiate DSM programs
5. Prepare and file 2008 IRP

The 2006 IRP has two significant supply-side resource additions that will require considerable preconstruction commitments; approximately 250 MW of coal-fired generation could come from either the expansion of an existing facility or the addition of a new generation facility and a 225 MW upgrade of the McNary to Boise transmission line. Idaho Power will continue its research efforts on these two resource additions during the fall of 2006.

The preferred portfolio also includes 250 MW of advanced coal technology in the form of an integrated gasification combined-cycle (IGCC) plant in the later stages of the planning period. The timing and commitment to the IGCC or other advanced coal facility will be assessed in future resource plans when additional feasibility information should be available concerning this technology.

Renewable Resource Education, Research and Development

In the 2004 IRP, Idaho Power expressed its commitment to renewable energy by stating, “Idaho Power will continue to fund education and demonstration energy projects with up to $100,000 of funding.” One of the projects supported with this commitment was the Foothills Environmental Learning Center in north Boise. Idaho Power’s support for this project included the installation of a 4.6 kW fuel cell and a 2.0 kW solar panel. In addition, Idaho Power repaired and upgraded the 15 kW solar energy project on the roof of its corporate headquarters in downtown Boise.

Continuing with its commitment to support renewable energy through education and demonstration projects, Idaho Power intends to commit up to an additional $100,000 to support renewable energy education and demonstration projects. Areas currently under consideration include solar energy projects and river flow energy conversion devices. At present, Idaho Power has not selected a specific project(s) to pursue with this funding.

Idaho Power intends to conclude the wind integration study during the fall of 2006. Idaho Power also has an open RFP for a geothermal resource which it intends to conclude in early 2007. Idaho Power is currently negotiating a power purchase contract with the successful bidder identified for the wind RFP issued in 2005. The 2006 preferred portfolio includes 250 MW of wind resources, 150 MW of geothermal resources, and 150 MW of CHP generation resources.

Portfolio Composition

The resource quantities identified in the preferred portfolio approximate the generation resources Idaho Power may acquire. Each resource and each resource acquisition has different characteristics and Idaho Power may alter the resource quantities to capitalize on market conditions, acquisition or development opportunities, and the specific characteristics of the bids offered during an individual RFP. Additionally, the results of Idaho Power's wind integration study may cause either an increase or decrease in the amount of wind generation included in the preferred portfolio. Idaho Power conducts the IRP process every two years which provides an opportunity to revisit the resource portfolio and make adjustments in response to changing conditions. The diversified resource portfolio allows Idaho Power to continue to reliably serve its customers while balancing costs, risks, and environmental concerns. A summary and timeline of the 2006 preferred portfolio is listed in Table 1-1.

IRP Methodology

A brief outline of Idaho Power's IRP methodology is as follows:

1. Assess present and estimate future conditions by:

    - Developing load, hydrologic, and generation forecasts
    - Determining energy surplus and deficiency on a monthly and hourly basis
    - Developing a peak-hour transmission analysis to estimate transmission deficiencies from the Pacific Northwest
    - Determining energy (monthly) and capacity (peak-hour) targets

Table 1-1. 2006 Preferred Portfolio Summary and Timeline

Summary			Timeline		
Resource	MW		Year	Resource	MW
Wind	250		2008	Wind (2005 RFP)	100
Geothermal (Binary)	150		2009	Geothermal (2006 RFP)	50
CHP	150		2010	CHP	50
Transmission	285		2012	Wind	150
Coal	250		2012	Transmission McNary–Boise	225
Regional IGCC Coal	250		2013	Wyoming Pulverized Coal	250
Nuclear	250		2017	Regional IGCC Coal	250
Total Nameplate	**1,585**		2019	Transmission Lolo–IPC	60
			2020	CHP	100
DSM Peak	187		2021	Geothermal	50
Energy (aMW)	1,089		2022	Geothermal	50
Transmission	285		2023	INL Nuclear	250
Peak	1,250			**Total Nameplate**	**1,585**

2. Inventory the potential supply-side and demand-side options and construct numerous portfolios capable of meeting energy and capacity targets by:
   - Estimating the costs of potential supply-side resources and demand-side programs using preliminary transmission interconnection cost estimates
   - Constructing practical portfolios based on supply-side resources and demand-side program costs and estimates
   - Simulating performance and determining the portfolio costs
   - Ranking each portfolio based on the present value of expected costs and selecting finalist portfolios for further risk analysis
3. Evaluate the finalist portfolios and identify a preferred portfolio by:
   - Refining the transmission integration cost analysis and incorporating backbone upgrades
   - Performing qualitative and quantitative risk analyses
4. Develop near-term and 10-year action plans based on the preferred portfolio

Public Policy Issues

A number of public policy issues have emerged since Idaho Power filed the 2004 IRP. These issues include green tags, emission offsets, financial disincentives for DSM programs, technology risks, and asset ownership. Each issue significantly affects long-term resource planning and the resulting portfolio of resources acquired. The near-term actions that Idaho Power takes to position itself and its customers for potential future regulations are also affected by a range of public policy issues.

Idaho Power discussed a range of public policy issues with the IRPAC and was hopeful a consensus opinion would emerge as a result of the discussions. While the topics were discussed at length, it became apparent that a consensus opinion would likely compromise individual positions on these important issues.

In lieu of being able to provide recommendations from the IRPAC on these issues, Idaho Power has chosen to present a series of questions and its position on each of the issues. Members of the IRPAC and the public are invited to provide specific comments on Idaho Power's proposed position on each of the topics. Public comments will help Idaho Power, the Idaho and Oregon PUCs, and the IRPAC assess the level of public support for each of the proposals.

Environmental Attributes or Green Tags

Due to a growing interest in renewable resources, over the past five years the electric industry has seen the output from renewable resources separated into two components, delivered energy and environmental attributes. Environmental attributes are more commonly referred to as "green tags" due to the positive environmental aspects, measured in dollars-per-MWh of production, of renewable resources. The emergence of two products stemming from one resource raises policy questions that are beginning to influence resource decisions for Idaho Power and other electric utilities. The main policy questions Idaho Power associates with green tags are:

- Should Idaho Power acquire the green tags for any renewable energy regardless of whether the energy is generated at an Idaho Power generation unit or purchased through a purchased power agreement, PURPA contract, energy exchange or some other arrangement?

- Should Idaho Power pay to acquire green tags even if the State of Idaho, the State of Oregon, and the federal government have no current statutory requirement for green tags through renewable portfolio standards (RPSs) or other regulations?
- Must Idaho Power possess green tags in order to accurately represent the renewable segments of its generation portfolio?
- Should future RFPs require the bidders to include green tags as part of the product and pricing?
- Should green tags be delivered to Idaho Power as part of any PURPA Qualifying Facility (QF) purchase?
- Should Idaho Power's voluntary Green Power Program express a preference to purchase green tags from developments within Idaho Power's service area?
- Should the costs associated with acquiring green tags be recoverable as a legitimate power purchase expense?

The 2006 IRP is the policy instrument that Idaho Power is using to introduce public discussion on the questions surrounding environmental attributes. This discussion is designed to bring these questions to the attention of the public through the Idaho and Oregon regulatory commissions for resolution.

Idaho Power believes it should purchase and retain green tags from any renewable resource built or purchased by Idaho Power for the supply of energy to its customers. In addition, the acquisition and retention of green tags is necessary to accurately represent the renewable energy component of Idaho Power's resource portfolio. Acquiring and retaining green tags assures Idaho Power's customers it has acquired the energy from renewable resources.

Idaho Power intends to acquire the green tags associated with energy generation, power purchases, and exchanges. Should future federal or state law impose renewable energy requirements, Idaho Power will be prepared to satisfy the environmental requirements with the green tags.

Any new RFPs involving renewable resources will require green tags be provided to Idaho Power as part of the purchase contract. Idaho Power also will pursue regulatory commission approval to require any new PURPA contracts to provide green tags as part of the standard avoided cost rates or as part of the negotiated PURPA purchased power contract.

Idaho Power's Green Power Program will not pursue the purchase of green tags from renewable resources contained in its resource portfolio, as Idaho Power already anticipates acquiring those tags. If green tags in Idaho become available from a resource not contained in Idaho Power's resource portfolio, it may pursue the purchase of those tags for the Green Power Program.

Idaho Power believes acquiring green tags is a prudent decision and it intends to seek recovery of the costs associated with purchasing green tags as a purchased power expense through regulatory filings. As an interim step, Idaho Power would also consider selling the green tags on a year-to-year basis until they were required by either its Green Power Program or the adoption of a federal or state renewable requirement. Revenue from any green tag sales would flow through the Power Cost Adjustment (PCA) mechanism.

Emission Offsets

Depending on market conditions, it may be possible to purchase emission offsets for less than the cost of the CO_2 emission adder used in the IRP analysis ($14 per ton). Some members of the IRPAC have suggested it would be prudent for Idaho Power to hedge the carbon emission risk by purchasing emission offsets today at prices less than the $14 per ton used in the IRP analysis.

There are differing opinions among IRPAC members regarding carbon offset purchases. The principal reason cited for not purchasing offsets today is the uncertainty associated with whether or not carbon offsets purchased today will meet future carbon control requirements and regulations.

Idaho Power believes it should investigate purchasing options to acquire future carbon offsets. Idaho Power could potentially reduce the large financial exposure of possible carbon taxes for the cost of the option premium. Idaho Power believes it should be able to recover the cost of purchasing emission offset options as well as the cost of any emission offsets purchased.

Financial Disincentives for DSM Programs

Idaho Power believes financial disincentives for DSM programs should be eliminated. One objective of an effective IRP is to assemble a diversified mix of demand-side and supply-side resources designed to minimize the societal costs of reliably supplying electricity to customers. The regulatory requirement is to treat supply-side and demand-side resources equally in the IRP. Idaho Power is a resource portfolio manager for its customers.

Like many utilities, Idaho Power recovers a portion of its fixed costs through the energy charges per kWh. Utilities could use two billing components; a fixed charge representing the capital investment and other fixed costs, and a kWh charge reflecting the variable cost of energy. However, low energy charges would likely encourage consumption. Electric utilities and regulatory commissions use the fixed costs to set the kWh charge high in order to discourage waste. In other words, a part of the cost of every kWh represents the system's fixed charges for existing plant and equipment; the rest of the kWh charge reflects the variable cost of producing that kWh of energy.

Idaho Power's rates are set based upon assumptions about annual kWh sales through the regulatory process in a general rate case. Whether actual energy consumption is above or below the initial assumptions defined in the rate case, every reduction in sales from efficiency improvements yields a corresponding reduction in fixed cost recovery to the detriment of the utility shareholder. Electric utilities such as Idaho Power support energy efficiency but the rate structure provides a disincentive for Idaho Power to encourage reduced energy consumption due to the resultant reduction in fixed cost recovery. Idaho Power continues to promote energy efficiency and supports the elimination of all financial disincentives for DSM using a process or mechanism that will allow implementation of effective DSM programs without penalizing its shareholders through reduced fixed-cost recovery.

IGCC Technology Risk

Idaho Power believes there are significant risks associated with developing an Integrated Gasification Combined Cycle (IGCC) generation resource given the current status of the technology. While there have been significant advances in IGCC technology at the component level, sustained long-term integrated operation in baseload utility service is still in the development stage.

At the present time, there are only two operational IGCC projects in the United States. In Idaho Power's opinion, two operational units do not qualify IGCC as a proven technology. Idaho Power believes IGCC is an important and promising technology that may play a significant role in the utility industry in the near future.

The 2006 IRP includes a 250 MW IGCC project in 2017. Idaho Power is interested in participating in the development of IGCC technology, but developing an IGCC project is not a risk that Idaho Power is comfortable taking alone. If a near-term opportunity existed to develop a jointly-owned IGCC project with a number of regional utilities, Idaho Power would consider participating in such a project. Although participation in a regional IGCC project is not specifically identified in the preferred portfolio, Idaho Power anticipates the planning flexibility exists to participate if a suitable opportunity is identified. Adding additional resources early in the planning period, such as a share in a regional IGCC project, may allow the 250 MW of IGCC identified in 2017 to be deferred, allowing Idaho Power and its customers to benefit from continued development and cost reductions in this technology.

Asset Ownership

Idaho Power can develop and own generation assets, rely on power purchase agreements (PPAs) and market purchases to supply the electricity needs of its customers, or use a combination of the two ownership strategies. Idaho Power expects to continue participating in the regional power market and enter into mid-term and long-term PPAs. However, when pursuing PPAs, Idaho Power must be mindful of imputed debt and its potential impact on Idaho Power's credit rating. In the long run, Idaho Power believes asset ownership results in lower costs for customers due to the capital and rate-of-return advantages inherent in a regulated electric utility. Idaho Power's preference is to own the generation assets necessary to serve its customer load.

2. Idaho Power Company Today

Customer and Load Growth

In 1990, Idaho Power Company had over 290,000 general business customers. Today, Idaho Power serves more than 456,000 general business customers in Idaho and Oregon. Firm peak-hour load has increased from less than 2,100 MW in 1990 to nearly 3,000 MW in the summers of 2002, 2003, and 2005. In July 2006, the peak-hour load reached 3,084 MW, which was a new system peak-hour record. Average firm load has increased from 1,200 aMW in 1990 to 1,660 aMW at the end of 2005. Summaries of Idaho Power's load and customer data are shown in Table 2-1 and Figure 2-1.

Simple calculations using the data in Table 2-1 suggest that each new customer adds nearly 6 kW to the peak-hour load and nearly 3 kW to average load. In actuality, residential, commercial, and irrigation customers generally contribute more to the peak-hour load, whereas industrial customers contribute more to average load. Industrial customers generally have a more consistent load shape whereas residential, commercial, and irrigation customers have a load shape with greater daily and seasonal variation.

Table 2-1. Historical Data (1990–2005)

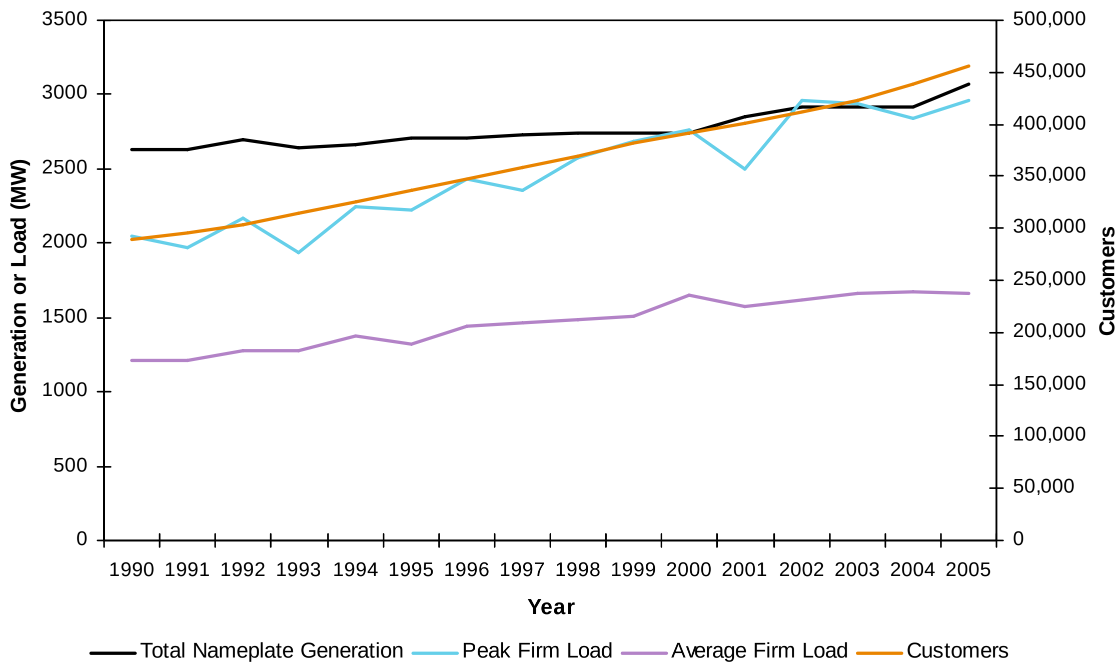
Year	Total Nameplate Generation (MW)	Peak Firm Load (MW)	Average Firm Load (MW)	Customers
1990	2,635	2,052	1,205	290,492
1991	2,635	1,972	1,206	296,584
1992	2,694	2,164	1,281	306,292
1993	2,644	1,935	1,274	316,564
1994	2,661	2,245	1,375	329,094
1995	2,703	2,224	1,324	339,450
1996	2,703	2,437	1,438	351,261
1997	2,728	2,352	1,457	361,838
1998	2,738	2,535	1,491	372,464
1999	2,738	2,675	1,552	383,354
2000	2,738	2,765	1,653	393,095
2001	2,851	2,500	1,576	403,061
2002	2,912	2,963	1,622	414,062
2003	2,912	2,944	1,657	425,599
2004	2,912	2,843	1,671	438,912
2005	3,085	2,961	1,660	456,104

Since 1990, Idaho Power's total nameplate generation has increased by 450 MW to 3,085 MW. The planned addition of a 170 MW combustion turbine at the Danskin Project in April 2008 will increase Idaho Power's total

Highlights

- Idaho Power had over 456,000 retail customers at the end of 2005.
- 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.
- Summertime peak-hour loads are expected to increase by 80 MW per year through 2025.
- Average load is expected to increase by 40 aMW per year through 2025.
- In 2005, DSM programs resulted in a savings of 41,267 MWh of electricity and a reduction in peak-hour loads of 47.5 MW.
- Idaho Power incurs a capital cost of approximately $5,500 to acquire the generation resources necessary to serve each new residential customer.

Figure 2-1. Historical Data (1990–2005)



nameplate generation to 3,255 MW. Actual generation is lower than total nameplate generation due to factors such as hydrological conditions, fuel purity, maintenance, and facility degradation. The 450 MW increase in capacity represents enough generation to serve about 80,000 customers at peak times and represents the average energy requirements of about 160,000 customers. Table 2-2 shows Idaho Power's changes in reported nameplate capacity since 1990.

Table 2-2. Changes in Reported Nameplate Capacity Since 1990

Resource	Type	MW	Year
Milner (addition)	Hydro	60	1992
Wood River Turbine (removal)	Thermal	−50	1993
Swan Falls (upgrade)	Hydro	15	1994, 1995
Twin Falls (upgrade)	Hydro	44	1995
Jim Bridger (upgrade)	Thermal	92	1997, 1998, 2002
Boardman (upgrade)	Thermal	3	1997
Valmy (upgrade)	Thermal	23	2001
Danskin (addition)	Thermal	90	2001
Bennett Mountain (addition)	Thermal	173	2005

Since 1990, Idaho Power has added more than 165,000 new customers. The simple peak-hour and average energy calculations mentioned earlier suggest the additional 165,000 customers require over 900 MW of additional peak-hour capacity and over 450 aMW of energy.

Idaho Power anticipates adding between 11,000 and 12,000 customers each year throughout the planning period. The same simple calculations suggest that peak-hour load requirements are expected to grow at about 80 MW per year and average energy is forecast to grow at about 40 aMW per year. More detailed customer and load forecasts are discussed in Chapter 3 and in *Appendix A–Sales and Load Forecast*.

The simple peak-hour load calculations indicate Idaho Power will need to add peaking capacity equivalent to the 90 MW Danskin plant every year or peaking capacity equivalent to the 173 MW Bennett Mountain plant every two years, throughout the entire planning period. The 10- year and near-term action plans to meet the requirements of the new customers are discussed in Chapters 7 and 8.

The generation costs per kW included in Chapter 5 help put the customer growth in perspective. Load research data indicate the average residential customer requires about 1.5 kW of baseload generation and 6.5 to 7 kW of peak-hour generation. Baseload generation capital costs are about $2,000 per kW for advanced coal technologies, wind, or geothermal generation, and peak-hour generation capital costs are about $500 per kW for a natural gas combustion turbine. The capital costs do not include fuel or any other operation and maintenance expenses.

Based on the capital cost estimates, each new residential customer requires about $3,000 of capital investment for 1.5 kW of baseload generation, plus $2,500 for an additional 5 kW of peak-hour generation for a total generation capital cost of $5,500. Other capital costs such as transmission costs, distribution costs, and customer systems costs are not included in the $5,500 capital generation requirement. The forecasted residential customer growth rate of 9,500 new customers per year translates into over $50 million of new generation plant capital per year to serve new residential customers.

Supply-Side Resources

Idaho Power has over 3,087 MW of installed or existing generation including 1,379 MW of thermal generation (nameplate capacity). In 2005, hydroelectric generation supplied 36 percent of the customers' energy needs, thermal generation supplied 42 percent, and purchased power supplied the remaining 22 percent of the customers' energy needs. Idaho Power's supply-side resources are listed in Table 2-3.

In addition to its existing resources, Idaho Power has made a commitment to develop two additional generation resources. In 2005, Idaho Power issued an RFP to acquire an additional peaking resource. The RFP was identified in the 2004 IRP as part of the 10-year action plan. Idaho Power evaluated the submitted bids and selected a 170 MW, simple-cycle, natural gas-fired combustion turbine proposed for the Danskin plant. Idaho Power is presently before the IPUC seeking a Certificate of Public Convenience and Necessity for the Danskin addition which is scheduled to be on-line in 2008.

Table 2-3. Supply-Side Resources

Resource	Type	Nameplate Capacity (MW)	Location
American Falls	Hydro	92	Upper Snake
Bliss	Hydro	75	Mid-Snake
Brownlee	Hydro	585	Hells Canyon
Cascade	Hydro	12	N Fork Payette
Clear Lake	Hydro	3	S Central Idaho
Hells Canyon	Hydro	392	Hells Canyon
Lower Malad	Hydro	14	S Central Idaho
Upper Malad	Hydro	8	S Central Idaho
Milner	Hydro	59	Upper Snake
Oxbow	Hydro	190	Hells Canyon
Shoshone Falls	Hydro	13	Upper Snake
Shoshone Falls (2010)	Hydro	62	Upper Snake
Lower Salmon	Hydro	60	Mid-Snake
Upper Salmon A	Hydro	18	Mid-Snake
Upper Salmon B	Hydro	17	Mid-Snake
C.J. Strike	Hydro	83	Mid-Snake
Swan Falls	Hydro	25	Mid-Snake
Thousand Springs	Hydro	9	S Central Idaho
Twin Falls	Hydro	53	Mid-Snake
Boardman	Thermal[1]	56	N Central Oregon
Jim Bridger	Thermal[1]	771	SW Wyoming
Valmy	Thermal[1]	284	N Central Nevada
Bennett Mountain	Thermal[2]	173	SW Idaho
Danskin	Thermal[2]	90	SW Idaho
Danskin (2008)	Thermal[2]	170	SW Idaho
Salmon	Thermal[3]	5	E Idaho

[1] Coal
[2] Natural Gas
[3] Diesel

Idaho Power has also committed to upgrading the 12.5 MW Shoshone Falls Hydroelectric Project. The project currently has three generator/turbine units with nameplate capacities of 11.5 MW, 0.6 MW, and 0.4 MW. The upgrade project involves replacing the two smaller units with a single 50 MW unit which will result in a net upgrade of 49 MW. The total nameplate capacity of the project will be 61.5 MW when the upgrade is completed in 2010. The Danskin addition and Shoshone Falls upgrade do not appear in the 2006 preferred portfolio because they are considered to be “committed resources.”

Hydro Resources

Idaho Power operates 18 hydroelectric generating plants located on the Snake River and its tributaries. Together, these hydroelectric facilities provide a total nameplate capacity of 1,708 MW and annual generation equal to approximately 970 aMW, or 8.5 million MWh annually under median water conditions.

The backbone of Idaho Power’s hydroelectric system is the Hells Canyon Complex in the Hells Canyon reach of the Snake River. The Hells Canyon Complex consists of the Brownlee, Oxbow, and Hells Canyon dams and the associated generating facilities. In a normal water year, the three plants provide approximately 67 percent of Idaho Power’s annual hydroelectric generation, and nearly 40 percent of the total energy generation. The Hells Canyon Complex alone annually generates approximately 5.84 million MWh, or 667 aMW, of energy under median water conditions. Water storage in Brownlee Reservoir also enables the Hells Canyon Complex to provide the major portion of Idaho Power’s peaking and load-following capability.

Idaho Power’s hydroelectric facilities upstream from Hells Canyon include the American Falls, Milner, Twin Falls, Shoshone Falls, Clear Lake, Thousand Springs, Upper and Lower Malad, Upper and Lower Salmon, Bliss, C.J. Strike, Swan Falls, and Cascade generating plants. Although the Mid-Snake projects of Upper and Lower Salmon, Bliss, and C.J. Strike, typically follow run-of-river operations, the Lower Salmon, Bliss, and C.J. Strike plants do provide a limited amount of peaking and load-following capability. When possible, the schedules at the plants are adjusted within the FERC license requirements to coincide with the daily system peak demand. All of the other upstream plants are operated as run-of-river projects.

Idaho Power has entered into a Settlement Agreement with the U.S. Fish and Wildlife Service that provides for a study of Endangered Species Act (ESA) listed snails and their habitat. The objective of the research study is to determine the impact of load following operations on the Bliss Rapids snail and the Idaho Spring snail. The five-year study requires Idaho Power to operate the Bliss and Lower Salmon facilities under varying operational constraints to facilitate the Idaho Spring snail research. Run-of-river operations during 2003 and 2004 will serve as the baseline, or control, for the study. Idaho Power will operate the plants to follow load during the 2005 and 2006 years of the study.

General Hells Canyon Complex Operations

Idaho Power operates the Hells Canyon Complex to comply with the existing FERC license, as well as voluntary arrangements to accommodate other interests, such as recreational use and environmental resources. Among the arrangements are the fall chinook plan voluntarily adopted by Idaho Power in 1991 to protect spawning and incubation of fall chinook below Hells Canyon Dam. The fall chinook is a species that is listed as threatened under the ESA.

Additional voluntary arrangements include the cooperative arrangement that Idaho Power had with federal interests between 1995 and 2001 to implement portions of the Federal Columbia River Power System (FCRPS) biological opinion flow augmentation program. The flow augmentation plan was viewed as a reasonable and prudent alternative under the biological opinion and the intent of the arrangement was to avoid jeopardizing the ESA-listed anadromous species as a result of FCRPS operations below the Hells Canyon Complex.

Brownlee Reservoir is the only one of the three Hells Canyon Complex reservoirs—and Idaho Power's only reservoir—with significant active storage. Brownlee Reservoir has 101 vertical feet of active storage capacity, which equals approximately one million acre-feet of water. Both Oxbow and Hells Canyon reservoirs have significantly smaller active storage capacities—approximately 0.5 percent and 1.0 percent of Brownlee Reservoir's volume, respectively.

Brownlee Reservoir Seasonal Operations

Brownlee Reservoir is a year-round, multiple-use resource for Idaho Power and the Pacific Northwest. Although the primary purpose is to provide a stable power source, Brownlee Reservoir is also used to control flooding, to benefit fish and wildlife resources, and for recreation.

Brownlee Dam is one of several Pacific Northwest dams that are coordinated to provide springtime flood control on the lower Columbia River. Between 1995 and 2001, Brownlee Reservoir, along with several other Pacific Northwest dams, was used to augment flows in the lower Snake River consistent with the FCRPS biological opinion. For flood control, Idaho Power operates the reservoir in accordance with flood control directions received from the U.S. Army Corps of Engineers (US Army COE) as outlined in Article 42 of the existing FERC license.

After the flood-control requirements have been met in late spring, Idaho Power attempts to refill the reservoir to meet peak summer electricity demands and provide suitable habitat for spawning bass and crappie. The full reservoir also offers optimal recreational opportunities through the Fourth of July holiday.

The U.S. Bureau of Reclamation (BOR) periodically releases water from BOR storage reservoirs in the upper Snake River in an effort to augment flows in the lower Snake River to help anadromous fish migrate past the FCRPS projects. The periodic releases are part of the flow-augmentation implemented by the 2000 FCRPS biological opinion. From 1995 through the summer of 2001, Idaho Power cooperated with the BOR and other interested parties by shaping (or pre-releasing) water from Brownlee Reservoir and occasionally contributing water from Brownlee Reservoir to the flow-augmentation efforts. The pre-released water was later replaced with water released by the BOR from the upper Snake River reservoirs.

Recognizing the federal responsibility for the flow-augmentation program, in 1996 the Bonneville Power Administration (BPA) entered into an energy exchange agreement with Idaho Power to facilitate Idaho Power's cooperation with the FCRPS flow-augmentation program. The BPA energy exchange agreement expired in April 2001 and even though Idaho Power expressed a willingness to continue to participate in the FCRPS flow-augmentation program through a similar arrangement, BPA chose not to renew the agreement. Although the agreement has expired, Idaho Power continues to support the flow-augmentation program to benefit anadromous fish migration.

Brownlee Reservoir's releases are managed to maintain constant flows below Hells Canyon Dam in the fall as a result of the voluntary fall chinook plan adopted by Idaho Power in 1991. The constant flow helps ensure sufficient water levels to protect fall chinook spawning nests, or redds. After the fall chinook spawn, Idaho Power attempts to refill Brownlee Reservoir by the first week of December to meet wintertime peak-hour loads. The fall spawning flows establish the minimum flow below Hells Canyon Dam throughout the winter until the fall chinook fry emerge in the spring.

Maintaining constant flows to protect the fall chinook spawning contributes to the need for additional generation resources during the fall months. The fall chinook operations result in lower reservoir elevations in Brownlee Reservoir and the lower reservoir elevations reduce the power production capability of the plant. The reduced power production may cause Idaho Power to have to acquire power from other sources to meet customer load.

Federal Energy Regulatory Commission Relicensing Process

Idaho Power's hydroelectric facilities, with the exception of the Clear Lake and Thousand Springs plants, operate under licenses issued by the Federal Energy Regulatory Commission (FERC). The process of relicensing Idaho Power's hydroelectric projects at the end of their initial 50-year license periods is well under way as shown in the schedule in Table 2-4.

Table 2-4. Hydropower Project Relicensing Schedule

Project	FERC License Number	Nameplate Capacity (MW)	Current License Expires	File FERC License Application
Hells Canyon Complex	1971	1,167	July 2005[1]	July 2003
Swan Falls	503	25	June 2010	June 2008
Bliss	1975	75	Aug. 2034	July 2032
Lower Salmon	2061	60	Aug. 2034	July 2032
Upper Salmon A	2777	18	Aug. 2034	July 2032
Upper Salmon B	2777	17	Aug. 2034	July 2032
Shoshone Falls	2778	13	Aug. 2034	July 2032
C.J. Strike	2055	83	Aug. 2034	July 2032
Upper/Lower Malad	2726	22	March 2035	Feb. 2033

[1] Operating under annual renewal of existing license

Applications to relicense Idaho Power's three Mid-Snake facilities (Upper Salmon, Lower Salmon, and Bliss) were submitted to FERC in December 1995. The application to relicense the Shoshone Falls Project was filed in May 1997. The application to relicense the C.J. Strike Project was filed in November 1998 and the application to relicense the Malad projects was filed in July 2002. The FERC issued new licenses for Upper Salmon, Lower Salmon, Bliss, C.J. Strike, and Shoshone Falls in August 2004 and for the Malad projects in March 2005.

The application to relicense the Hells Canyon Complex was filed in July 2003. The relicensing application for the Swan Falls Project will be filed in 2008.

Failure to relicense any of the existing hydropower projects at a reasonable cost will create upward pressure on the current electric rates of Idaho Power customers. The relicensing process also has the potential to decrease available capacity and increase the cost of a project's generation through additional operating constraints and requirements for environmental protection, mitigation, and enhancement (PM&E) imposed as a condition for relicensing. A reduction in the operational flexibility of Idaho Power's hydro system will also negatively impact the ability to integrate wind resources. Idaho Power's goal throughout the relicensing process is to maintain the low cost of generation at the hydroelectric facilities while implementing non-power measures designed to protect and enhance the river environment.

No reduction of the available capacity or operational flexibility of the hydroelectric plants to be relicensed has been assumed as part of the 2006 IRP. If capacity reductions or reductions in operational flexibility do occur as a result of the relicensing process, Idaho Power will adjust future resource plans to reflect the need for additional capacity resources in order to maintain the existing level of reliability.

Environmental Analysis

The National Environmental Policy Act requires that the FERC perform an environmental assessment of each hydropower license application to determine whether federal action will significantly impact the quality of the natural environment. If so, then an environmental impact statement (EIS) must be prepared prior to granting a new license. The FERC has recently issued the draft EIS for the

Hells Canyon Complex which is currently being reviewed by Idaho Power. The draft EIS was noticed in the Federal Register on August 4, 2006, which is the beginning of the 60-day comment period.

Opportunity for additional public comment on the draft EIS and final EIS for the Hells Canyon Complex will occur before the license order is issued. Because the project's current license expired before a new license has been issued, an annual operating license is issued by the FERC pending completion of the licensing process.

Hydroelectric Relicensing Uncertainties

Idaho Power is optimistic that the relicensing process will be completed in a timely fashion. However, prior experience indicates the relicensing process will result in an increase in the costs of generation from the relicensed projects. The increased costs are associated with the requirements imposed on the projects as a condition of relicensing. Because the Hells Canyon Complex relicensing is not complete at this time, Idaho Power cannot reasonably estimate the impact of the relicensing process on the generating capability or operating costs of the relicensed projects. At the time of the 2008 IRP, Idaho Power will have better information regarding the power generation impacts of relicensing.

Baseload Thermal Resources

Jim Bridger

Idaho Power owns a one-third share of the Jim Bridger coal-fired plant located near Rock Springs, Wyoming. The plant consists of four nearly identical generating units. Idaho Power's one-third share of the nameplate capacity of the Jim Bridger plant currently stands at 771 MW. After adjustment for scheduled maintenance periods, estimated forced outages, de-ratings, and transmission losses, the annual energy-generating capability of Idaho Power's share of the plant through the 2006–2025 planning period is approximately 575 aMW. PacifiCorp has two-thirds ownership and is the operating partner of the Jim Bridger facility.

Valmy

Idaho Power owns a 50 percent share, or 284 MW, of the 568 MW (nameplate) Valmy coal-fired plant located east of Winnemucca, Nevada. The plant is owned jointly with Sierra Pacific Power Company which performs operation and maintenance services. After adjustment for scheduled maintenance periods, estimated forced outages, de-ratings, and transmission losses, the annual energy-generating capability of Idaho Power's share of the Valmy plant through the 2006–2025 planning period is approximately 230 aMW.

Boardman

Idaho Power owns a 10 percent share, or 56 MW, of the 560 MW (nameplate) coal-fired plant near Boardman, Oregon, operated by Portland General Electric Company. After adjustment for scheduled maintenance periods, estimated forced outages, de-ratings, and transmission losses, the annual energy-generating capability of Idaho Power's share of the Boardman plant through the 2006–2025 planning period is approximately 52 aMW.

Peaking Thermal Resources

Danskin

Idaho Power owns and operates the Danskin plant, a 90 MW natural gas-fired project. The plant consists of two 45 MW Siemens–Westinghouse W251B12A combustion turbines. The 12-acre facility, constructed during the summer of 2001, is located northwest of Mountain Home, Idaho. The Danskin plant operates as needed to support system load.

Bennett Mountain

Idaho Power owns and operates the Bennett Mountain plant, a 173 MW Siemens–Westinghouse 501F simple cycle, natural gas-fired combustion turbine located near the Danskin plant in Mountain Home, Idaho. The Bennett Mountain plant operates as needed to support system load.

Salmon Diesel

Idaho Power owns and operates two diesel generation units located at Salmon, Idaho. The Salmon units have a combined nameplate rating of 5 MW and are primarily operated during emergency conditions.

Public Utility Regulatory Policies Act

In 1978 the United States Congress passed the Public Utility Regulatory Policies Act requiring electric utilities such as Idaho Power to purchase the energy from Qualifying Facilities (QF). Qualifying Facilities are small, privately-owned, renewable generation projects or small cogeneration projects. The individual states were given the task of establishing the terms and conditions, including price, that each state's utilities are required to pay as part of the PURPA agreements. Idaho Power operates in Idaho and Oregon and has a different set of contract requirements for PURPA projects for each state jurisdiction.

Idaho Projects

The IPUC has established two classes of PURPA projects:

1. **Non-firm projects:** Non-firm contracts are for project operators who have no desire to commit to a contract term or commit to any quantity of energy deliveries. A non-firm agreement contains pricing based on the monthly market value of energy for each month when the project delivers energy to Idaho Power.
2. **Firm projects:** Firm contracts are for project operators who are willing to make a commitment on both the contract term and the specific levels of energy delivery.

As specified by various IPUC orders:

- Term of the agreements cannot exceed 20 years.
- Projects that deliver 10 aMW or less, measured on a monthly energy delivery basis, are eligible for the IPUC Published Avoided Cost.
- Projects that deliver greater than 10 aMW, measured on a monthly energy delivery basis, will receive negotiated energy prices based upon Idaho Power's IRP energy pricing models and the specific delivery characteristics of the generation project.

The Idaho PURPA Published Avoided Cost model is designed to estimate the cost of an additional utility resource that will be avoided by the addition of the PURPA project. The current Idaho PURPA avoided cost model assumes that a natural gas combined-cycle turbine is the surrogate avoided resource that Idaho utilities avoid through the addition of PURPA resources. Idaho Power has not selected a natural gas combined-cycle plant in the preferred resource portfolio since the 2000 IRP. Idaho Power may propose using a different type of resource for the surrogate avoided resource to determine published avoided costs in a future regulatory proceeding.

The Idaho PURPA avoided-cost model requires forecast inputs, including expected plant life, estimated plant cost, expected year of plant construction, estimated fixed O&M costs, estimated variable O&M costs, estimated cost escalation rates, estimated fuel cost and the associated fuel cost escalation rate, and assumed plant design characteristics such as the plant heat rate. Of the inputs, fuel cost and the associated fuel cost escalation rate have the greatest influence on the resulting PURPA energy price.

In IPUC Order 29124, the IPUC adopted the Northwest Power and Conservation Council's (NWPCC) median natural gas price forecast for the fuel cost input. The IPUC updates the PURPA Published Avoided Cost whenever new forecasts from the NWPCC are published.

The most recent NWPCC natural gas price forecast was incorporated in IPUC Order 29646, dated December 1, 2004, which established the Idaho Power PURPA Published Avoided Cost to be 60.99 Mills per kWh (levelized rate, generation plant on-line in 2006, and 20-year contract term).

Oregon Projects

The OPUC, the utilities serving Oregon, and other interested parties are currently in the process of revising the processes, terms and conditions for PURPA projects located in the State of Oregon. At this time, Oregon Schedule 85 requires Idaho Power to purchase energy from PURPA projects with less than 10 MW of nameplate generation. As specified by Oregon Schedule 85:

- The contract must follow the standard PURPA agreement on file with the OPUC
- Term of the agreement cannot exceed 20 years

There are three pricing options under Oregon Schedule 85:

1. **Fixed Price Option:** The energy price is fixed for all energy deliveries. The fixed-price option is very comparable to the IPUC Published Avoided Costs method.
2. **Deadband Option:** The deadband option contains a fixed-price component plus a variable-price component that is based on monthly natural gas prices. The calculated gas price is then confined between a cap and floor creating the "deadband."
3. **Gas Index Option:** The gas price option contains a fixed-price component plus a variable-price component that is based on monthly natural gas prices.

The current Schedule 85 proceeding at the OPUC is addressing the PURPA terms and conditions for projects with a nameplate rating greater than 10 MW.

Cogeneration and Small Power Producers (CSPP)

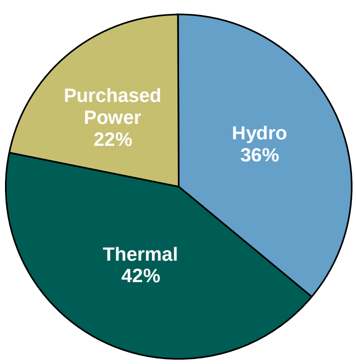
Idaho Power has over 90 contracts with independent power producers for over 400 MW of nameplate capacity. The CSPP generation facilities consist of low-head hydro projects on various irrigation canals, cogeneration projects at industrial facilities, and various small renewable power projects. Idaho Power is required to take the energy from the projects as the energy is generated and it cannot dispatch the CSPP projects. PURPA and various Idaho and Oregon PUC orders govern the rules, rates, and requirements for independent power producers.

Purchased Power

Idaho Power relies on regional markets to supply a significant portion of energy and capacity. Idaho Power is especially dependent on the regional markets during peak periods. Reliance on regional markets has benefited Idaho Power customers during times of low prices as the costs of purchases, the revenue from surplus sales, and fuel expenses are shared with customers through the PCA. However, the reliance on regional markets can be costly in times of high prices such as during the summer of 2001. As part of the 2002 IRP process, the public, the IPUC, and the Idaho Legislature all suggested that the time had come for Idaho Power to reduce the reliance on regional market purchases. Greater planning reserve margins or the use of more conservative water planning criteria were suggested as methods requiring Idaho Power to acquire more firm resources and reduce its reliance on market purchases. Idaho Power adopted more conservative water planning criteria in the 2002 IRP and has continued utilizing the more conservative water planning criteria in the 2004 and 2006 Integrated Resource Plans.

Figure 2-2 shows the percentages of Idaho Power's energy resources to serve customer load in 2005. As recently as 1998, the proportion of hydro generation exceeded 50 percent and purchased power was only 15 percent of the resource portfolio. Customer growth combined with below normal water lowered the proportion of hydro to 36 percent and increased purchased power to 22 percent of the portfolio in 2005.

Figure 2-2. 2005 Energy Sources



Transmission Interconnections

Description

The Idaho Power transmission system is a key element serving the needs of Idaho Power's retail customers. The 345 kV, 230 kV, and 138 kV main grid system is essential for the delivery of bulk power supply. Figure 2-3 shows the principal grid elements of Idaho Power's high-voltage transmission system.

Capacity and Constraints

Idaho Power's transmission connections with regional utilities provide paths over which off-system purchases and sales are made. The transmission interconnections and the associated power transfer capacities are identified in Table 2-5. The capacity of a transmission path may be less than the sum of the individual circuit capacities. The difference is due to a number of factors, including load distribution, potential outage impacts, and surrounding system limitations. In addition to the restrictions on interconnection capacities, other internal transmission constraints may limit Idaho Power's ability to access specific energy markets. The internal transmission paths needed to import resources from other utilities and their respective potential constraints are also shown in Figure 2-3 and Table 2-5.

Brownlee–East Path

The Brownlee–East transmission path is on the east side of the Northwest Interconnection shown in Table 2-5. Brownlee–East is comprised of the 230 kV and 138 kV lines east of the Brownlee/Oxbow/Quartz area. When the Midpoint–Summer Lake 500 kV line is included with the Brownlee–East path, the path is typically referred to as the Brownlee–East Total path. The constraint on the Brownlee–East transmission path is within Idaho Power's main transmission grid and located in the area between Brownlee and Boise on the west side of the system.

The Brownlee–East path is most likely to face summer constraints during normal to high water years. The constraints result from a combination of Hells Canyon Complex hydro generation flowing east into the Treasure Valley, concurrent with transmission wheeling obligations and purchases from the Pacific

Figure 2-3. Transmission System

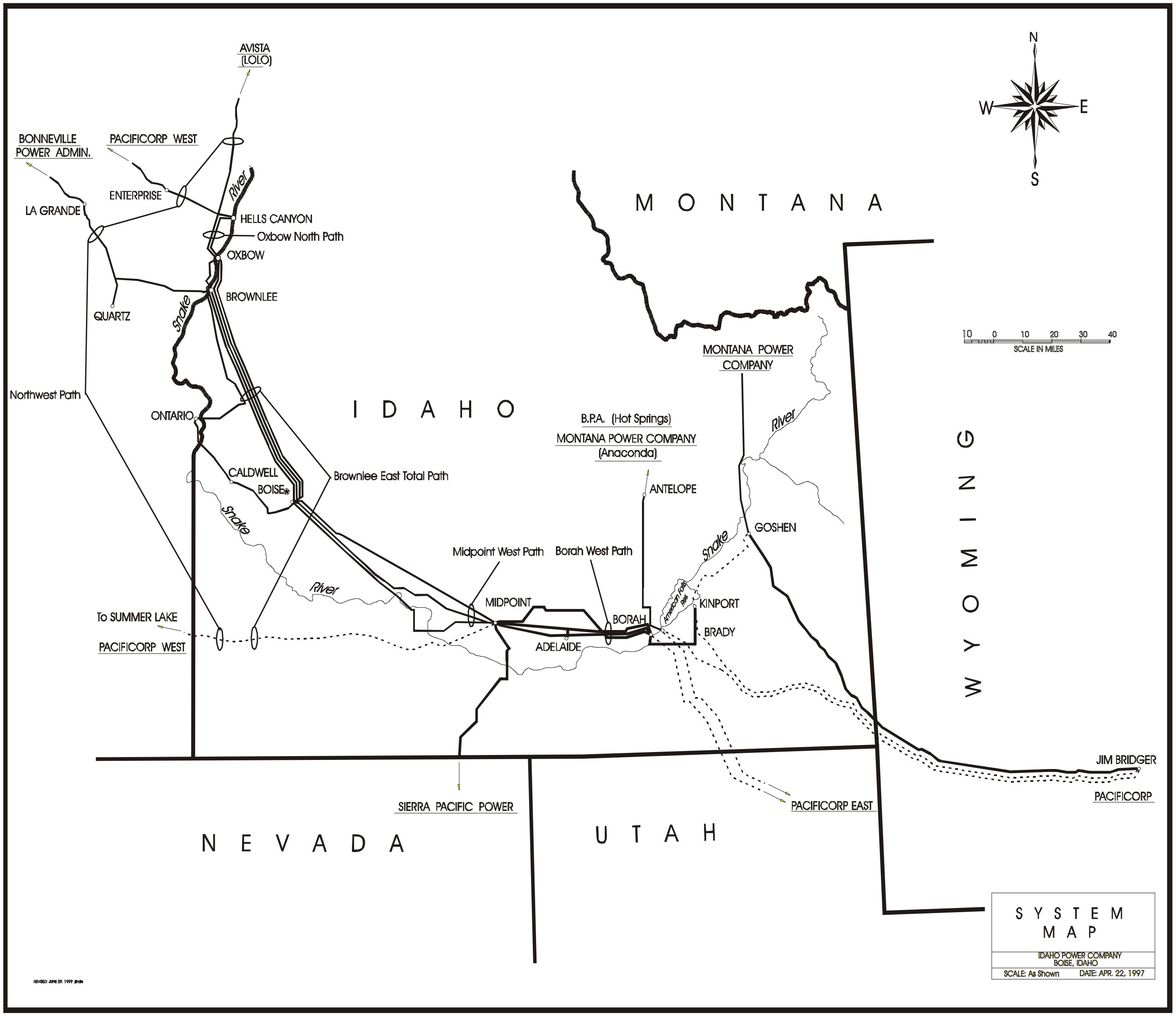


Table 2-5. Transmission Interconnections

Transmission Interconnections	Capacity		Line or Transformer	Connects Idaho Power To
	To Idaho	From Idaho		
Northwest	1,090 to 1,200 MW	2,400 MW	Oxbow-Lolo 230 kV Midpoint-Summer Lake 500 kV Hells Canyon-Enterprise 230 kV Quartz Tap-LaGrande 230 kV Hines-Harney 138/115 kV	Avista PacifiCorp (PPL Division) PacifiCorp (PPL Division) BPA BPA
Sierra	262 MW	500 MW	Midpoint-Humboldt 345 kV	Sierra Pacific Power
Eastern Idaho[1]			Kinport-Goshen 345 kV Bridger-Goshen 345 kV Brady-Antelope 230 kV Blackfoot-Goshen 161 kV	PacifiCorp (PPL Division) PacifiCorp (PPL Division) PacifiCorp (PPL Division) PacifiCorp (PPL Division)
Utah (Path C)[2]	775 to 950 MW	830 to 870 MW	Borah-Ben Lomond 345 kV Brady-Treasureton 230 kV American Falls-Malad 138 kV	PacifiCorp (PPL Division) PacifiCorp (PPL Division) PacifiCorp (PPL Division)
Montana[3]	79 MW 87 MW	79 MW 87 MW	Antelope-Anaconda 230 kV Jefferson-Dillon 161 kV	NorthWestern Energy NorthWestern Energy
Pacific (Wyoming)	600 MW	600 MW	Jim Bridger 345/230 kV	PacifiCorp (Wyoming Division)

Power Transfer Capacity for Idaho Power's Interconnections

[1] The Idaho Power-PacifiCorp interconnection total capacities in eastern Idaho and Utah include Jim Bridger resource integration.

[2] The Path C transmission path also includes the internal PacifiCorp Goshone-Grace 161 kV line.

[3] The direct Idaho Power-Montana Power schedule is through the Brady-Antelope 230 kV line and through the Blackfoot-Goshen 161 kV line that are listed as an interconnection with PacifiCorp. As a result, Idaho-Montana and Idaho-Utah capacities are not independent.

Northwest. Transmission wheeling obligations also affect southeastern flow into and through southern Idaho. Significant congestion affecting southeast energy transmission flow from the Pacific Northwest may also occur during the month of December. Restrictions on the Brownlee–East path limit the amount of energy Idaho Power can import from the Hells Canyon Complex, as well as off-system purchases from the Pacific Northwest.

The Brownlee–East Total constraint is the primary restriction on imports of energy from the Pacific Northwest during normal and high water years. If new resources are sited west of this constraint, additional transmission capacity will be required to remove the existing Brownlee–East transmission constraint to deliver the energy from the additional resources to the Boise/Treasure Valley load area.

Oxbow–North Path

The Oxbow–North path is a part of the Northwest Interconnection and consists of the Hells Canyon–Brownlee and Lolo–Oxbow 230 kV double-circuit line. The Oxbow–North path is most likely to face constraints during the summer months when high northwest-to-southeast energy flows and high hydro production levels coincide. Congestion on the Oxbow–North path also occurs during the winter months of November and December due to winter peak conditions throughout the region.

Northwest Path

The Northwest path consists of the 500 kV Midpoint–Summer Lake line, the three 230 kV lines between the Northwest and Brownlee, and the 115 kV interconnection at Harney. Deliveries of purchased power from the Pacific Northwest flow over these lines. During peak summer periods, total purchased power needs may exceed the capability of the Northwest Path. If new resources are sited west of this constraint, additional transmission capability will be needed to transmit the energy into Idaho Power's control area.

Borah–West Path

The Borah–West transmission path is within Idaho Power's main grid transmission system located west of the eastern Idaho, Utah Path C, Montana and Pacific (Wyoming) interconnections shown in Table 2-5. The Borah–West path consists of the 345 kV and 138 kV lines west of the Borah/Brady/Kinport area. The Borah–West path will be of increasing concern because its capacity is fully utilized by existing wheeling obligations.

There is a strong probability that many of the generation alternatives considered in the 2006 IRP will be sited east of the Borah–West transmission path. Transmission improvements on the Borah–West transmission path will be required to transfer energy from any new generation sited on the east side of Idaho Power's service area to serve load growth in the Boise area. Idaho Power is presently upgrading the capacity of the Borah–West path. The transmission improvements identified in the 2004 IRP will increase the Borah–West transmission capacity by 250 MW and are expected to be completed in May 2007. The increased transmission capacity will be available to serve Idaho Power's native load requirements with new generating resources located east of the Borah–West constraint.

Midpoint–West Path

The Midpoint–West path is another transmission constraint that exists just west of the Midpoint area. The Midpoint–West constraint is slightly less restrictive than the Borah–West constraint at the present time. Relatively small improvements on the Borah–West constraint may result in the Midpoint–West constraint limiting east-to-west transfers. Any significant improvement in the east-to-west transfers will more than likely require considerable upgrades to both the Borah–West and Midpoint–West paths. The addition of a new combustion turbine at the Danskin site near Mountain Home, Idaho will necessitate transmission improvements to the Midpoint–West path. The most significant improvements are the addition of two new 230 kV transmission lines; one in the area around Mountain Home, Idaho from the Bennett Mountain 173 MW combustion turbine to the combustion turbines at the Danskin site north of Mountain Home and the other 230 kV line from the Danskin site to the Mora Substation near Boise.

Regional Transmission Organizations

In 1999, the FERC issued Order 2000 to encourage voluntary membership in regional transmission organizations (RTOs). FERC Order 2000 precipitated considerable activity within the Pacific Northwest focused on the decisions about whether to create an RTO and how it should operate. To date, the effort to form an RTO in the Pacific Northwest has been unsuccessful. Idaho Power will continue to be an active participant in efforts to determine an appropriate structure for provision of transmission service within the Pacific Northwest.

Off-System Purchases, Sales, and Load-Following Agreements

Idaho Power currently has two, fixed-term, off-system sales contracts. The contracts, expiration dates, and average sales amounts are shown in Table 3-3 in Chapter 3.

The City of Weiser, Idaho has a full-requirements, fixed-term sales contract with Idaho Power. Under the full-requirements contract, Idaho Power is responsible for supplying the entire load of the city. The City of Weiser is located entirely within Idaho Power's load-control area.

A fixed-term sales contract with Raft River Rural Electric Cooperative was established as a full-requirements contract after being approved by the FERC and the Public Utilities Commission of Nevada. The Raft River Cooperative is the electric distribution utility serving Idaho Power's former customers in Nevada. On April 2, 2001, Idaho Power sold the transmission and distribution facilities, along with the rights-of-way that serve approximately 1,250 customers in northern Nevada and 90 customers in southern Owyhee County, Idaho, to the Raft River Cooperative. The area sold is located entirely within Idaho Power's load-control area.

Idaho Power and Montana's NorthWestern Energy have negotiated a load-following agreement in which Idaho Power provides NorthWestern Energy with 30 MW of load-following service. The agreement includes provisions allowing Idaho Power to receive energy from NorthWestern Energy on the east side of the system during summer months. Renewal of the load-following agreement with NorthWestern Energy will depend on a number of factors, including the amount of wind generation on Idaho Power's system. Idaho Power also has a load-following agreement with NorthWestern for serving its load in Salmon, Idaho, which is located in NorthWestern's load control area. Both agreements are automatically renewed each year with the consent of Idaho Power and NorthWestern Energy.

Demand-Side Management

Idaho Power includes DSM programs along with supply-side resources and transmission interconnections in the IRP resource stack. Idaho Power develops and implements demand-side programs to help manage energy demand.

The two primary objectives of the DSM programs are to:

1. Acquire cost-effective resources in order to more efficiently meet the electrical systems needs; and
2. Provide Idaho Power customers with programs and information to help them manage their energy use and lower their bills.

Idaho Power achieves the two objectives through the development and implementation of programs with specific energy, economic, and customer objectives. Under the DSM umbrella, the programs fall into four categories: Demand Response, Energy Efficiency, Market Transformation, and Other Programs and Activities.

During 2005, the IPUC approved Idaho Power's request to increase the Rider from 0.5 to 1.5% of base rate revenues (Case No. IPC-E-04-29). The funding increase became effective on June 1, 2005. In July 2005, Idaho Power filed a request with the OPUC to implement a Rider in its Oregon service area. The Oregon Rider is identical to the Rider approved in Idaho. The OPUC approved the Oregon Rider in August 2005 (Advice No. 05-03).

Idaho Power relies on the input from the EEAG to provide customer and public interest review of DSM programs. Formed in 2002 and meeting several times annually, the EEAG currently consists of 12 members representing a cross-section of customer segments including residential, industrial, commercial, irrigation, elderly, low-income, and environmental interests as well as members representing the Public Utility Commissions of Idaho and Oregon and Idaho Power. In addition to the EEAG, Idaho Power solicits further customer input through stakeholder groups in the industrial, irrigation, and commercial customer segments.

In 2005, Idaho Power agreed to a renewal agreement funding the Northwest Energy Efficiency Alliance (Alliance) for five years (2005–2009). The Alliance's efforts in the Pacific Northwest affect Idaho Power's customers through the regional market transformation efforts as well as providing structural support for Idaho Power's local market transformation programs. Idaho Power continues to leverage the support provided by the Alliance in the development and marketing of local programs, resulting in efficiencies of program implementation.

In October 2005, Idaho Power began its fifth year of a five-year agreement with the BPA through the Conservation and Renewable Discount (C&RD) program. Idaho Power operates several programs with the C&RD funding including Energy House Calls and Rebate Advantage. The BPA has introduced a replacement program called the Conservation Rate Credit (CRC) program available from 2007–2009 and Idaho Power will be eligible for early participation.

Overview of Program Performance

In 2005, DSM programs at Idaho Power continued to grow and to show steady improvement in customer satisfaction. The six programs identified for implementation in the 2004 IRP were in place and operating by the end of 2005. The two Demand Response programs—Irrigation Peak Rewards and A/C Cool Credit—resulted in a reduction of summertime peak-hour load of over 43 MW. The four Energy Efficiency programs—Industrial Efficiency, Commercial Building Efficiency, ENERGY STAR® Homes Northwest, and Irrigation Efficiency Rewards—resulted in an annual savings of 13,946 MWh.

In addition to the DSM programs identified in the 2004 IRP, during 2005 Idaho Power operated several other Energy Efficiency programs targeting residential customers including: Weatherization Assistance for Qualified Customers (previously known as Low Income Weatherization Assistance program, or LIWA), Energy House Calls, Rebate Advantage, and Oregon Residential Weatherization. In 2005, Idaho Power also joined the regional Savings with a Twist program sponsored by BPA. This program provides Idaho Power customers with low-priced compact fluorescent light (CFL) bulbs in local retail stores. These five residential energy-efficiency programs created a savings of 6,756 MWh in 2005.

Idaho Power continues to realize significant Market Transformation benefits through Idaho Power's partnership with the Alliance, which estimates 20,054 MWh were saved in Idaho Power's service area in 2005. Idaho Power also participated in small demonstration projects and educational opportunities with an estimated savings of 512 MWh in 2005.

Table 2-6 shows the 2005 annual energy savings and summer peak reduction associated with each of the DSM program categories. The energy savings totaled 41,267.5 MWh and the estimated peak reduction was 47.5 MW during the 2005 summer peak. All energy statistics presented in this report are net of transmission line losses unless otherwise noted.

Table 2-6. 2005 DSM Energy and Peak Impact

	MWh	Peak MW
Demand Response	–	43.0
Energy Efficiency	20,701.5	2.4[1]
Market Transformation	20,053.8	2.1[1]
Other Programs and Activities	512.2	–
Total 2005	**41,267.5**	**47.5**

[1] Based on annual aMW

3. Planning Period Forecasts

Load Forecast

Future demand for electricity by customers in Idaho Power's service area is defined by a series of six load forecasts, reflecting a range of load uncertainty resulting from differing economic growth and weather-related assumptions.

Table 3-1 summarizes three forecasts that represent Idaho Power's estimate of the boundaries of its annual total load growth over the planning period considering economic and demographic impacts on the load forecast (normal weather is assumed). There is a 90 percent probability that Idaho Power's load growth will exceed the Low Load Growth Forecast, a 50 percent probability of load growth exceeding the Expected Load Growth Forecast, and a 10 percent probability that load growth will exceed the High Load Growth Forecast. The projected 20-year average annual compound growth rate in the expected load forecast is 1.9 percent. Idaho Power believes the Expected Load Growth Forecast is the most likely forecast and uses this forecast as the basis for further analysis of weather-related uncertainties presented in Table 3-2.

Table 3-1. Load Forecast Probability Boundaries (aMW)

	Growth Forecast		
Year	Low Load	Expected Load	High Load
2005 (Actual)	1,693	1,693	1,693
2006	1,710	1,746	1,783
2007	1,737	1,786	1,843
2008	1,763	1,822	1,895
2009	1,788	1,857	1,943
2010	1,816	1,892	1,993
2011	1,834	1,918	2,031
2012	1,851	1,942	2,067
2013	1,880	1,978	2,115
2014	1,909	2,014	2,163
2015	1,937	2,051	2,210
2016	1,967	2,089	2,258
2017	1,996	2,128	2,306
2018	2,027	2,167	2,355
2019	2,058	2,207	2,405
2020	2,090	2,248	2,456
2021	2,123	2,290	2,508
2022	2,157	2,333	2,561
2023	2,191	2,376	2,614
2024	2,226	2,419	2,669
2025	2,261	2,464	2,724
Growth Rate *(2005–2025)*	1.5%	1.9%	2.4%

Table 3-2 summarizes three forecasts that represent Idaho Power's estimate of its annual total load growth over the planning period considering normal, 70th percentile and 90th

Highlights

- ► Idaho Power's average load is expected to grow at a rate of 1.9% annually throughout the planning period.
- ► The number of residential customers in Idaho Power's service area is expected to increase from around 381,000 at the end of 2005 to nearly 571,000 by the end of the planning period in 2025.
- ► Based on recent history, Snake River streamflows are expected to continue to decline by approximately 53 cfs per year which results in a loss of hydroelectric generation of 25–30 aMW annually.
- ► Hydrologic conditions were worse than the 90th percentile in 2001 and worse than the 70th percentile from 2001–2005.

percentile weather impacts (explained in more detail below) on the Expected Load Growth Forecast shown in Table 3-1. Idaho Power uses the 70th percentile forecast as the basis for resource planning. The 70th percentile forecast is based on 70th percentile weather to forecast average monthly load, 70th percentile water to forecast hydro generation, and 95th percentile monthly weather to forecast monthly peak-hour load. The 70th percentile forecast is referenced throughout the Integrated Resource Plan.

Table 3-2. Range of Total Load Growth Forecasts (aMW)

Year	Median	70th Percentile	90th Percentile
2005 (Actual)	1,693	1,693	1,693
2006	1,746	1,786	1,855
2007	1,786	1,827	1,897
2008	1,822	1,864	1,935
2009	1,857	1,899	1,972
2010	1,892	1,935	2,008
2011	1,918	1,961	2,036
2012	1,942	1,986	2,061
2013	1,978	2,023	2,099
2014	2,014	2,059	2,136
2015	2,051	2,097	2,175
2016	2,089	2,135	2,213
2017	2,128	2,174	2,254
2018	2,167	2,214	2,294
2019	2,207	2,255	2,336
2020	2,248	2,295	2,377
2021	2,290	2,338	2,421
2022	2,333	2,381	2,465
2023	2,376	2,425	2,510
2024	2,419	2,469	2,555
2025	2,464	2,515	2,601
Growth Rate *(2005–2025)*	1.9%	2.0%	2.2%

Expected Load Forecast–Economic Impacts

The expected load forecast represents the most probable projection of service area load growth during the planning period. The forecast for total load growth is determined by summing the load forecasts for individual classes of service, as described in *Appendix A–Sales and Load Forecast*. For example, the expected total load growth of 1.9 percent is comprised of residential load growth of 1.8 percent, commercial load growth of 2.5 percent, no growth in the irrigation sector, industrial load growth of 2.3 percent, and additional firm load growth of 1.0 percent.

Economic growth assumptions influence the individual customer-class forecasts. The number of service area households and various employment projections, along with customer consumption patterns, are used to form load projections. Economic growth information for Idaho and its counties can be found in *Appendix C–Economic Forecast.*

The number of households in Idaho is projected to grow at an annual average rate of 1.7 percent during the 20-year forecast period. Growth in the number of households within individual counties in Idaho Power's service area differs from statewide household growth patterns. Service area household projections are derived from individual county household forecasts. Growth in the number of households within the Idaho Power service area, combined with estimated consumption per household, results in the previously mentioned 1.8 percent residential load growth rate. The number of residential customers in Idaho Power's service area is expected to increase 2.0 percent annually from around 381,000 at the end of 2005 to nearly 571,000 by the end of the planning period in 2025.

Expected Load Forecast–Weather Impacts

The expected case load forecast assumes median temperatures and median precipitation meaning there is a 50 percent chance that loads will be higher or lower than the expected case load forecast due to colder-than-median or hotter-than-median temperatures and wetter-than-median or drier-than-median precipitation. Since actual customer loads can vary significantly depending upon weather conditions, two alternative scenarios are analyzed to address load variability due to weather. Idaho Power has generated load forecasts for 70th percentile weather and 90th percentile weather. Seventieth percentile weather means that in seven out of 10 years, the load is expected to be less than the forecast and in three out of 10 years, the load is expected to exceed the forecast. Ninetieth percentile load has a similar definition.

Cold winter days create high heating load. Hot, dry summers create both high cooling and irrigation loads. Heating degree-days (HDD), cooling degree-days (CDD), and growing degree-days (GDD) are used to quantify the weather and estimate a load forecast. In the winter, maximum load occurs with the highest recorded levels of HDD. In the summer, maximum load occurs with the highest recorded levels of CDD and GDD. These concepts are further explained in *Appendix A–Sales and Load Forecast.*

For example, according to the Boise Weather Service, the median number of HDD in December over the 1948–2005 time period is 1,040 HDD. The coldest December over the same time period was December 1985 when there were 1,619 HDD recorded by the Boise Weather Service.

For December, the 70th percentile HDD is 1,069 HDD. The 70th percentile value is likely to be exceeded in three out of 10 years on average. The 90th percentile HDD is 1,185 HDD and is likely to be exceeded in one out of 10 years on average. Forecast load percentile calculations were used in each month throughout the year for the weather-sensitive customer classes which include residential, commercial, and irrigation customers. The 70th percentile is used to forecast average monthly load for energy calculations, and the 95th percentile is used to forecast monthly peak-hour load for generation and transmission capacity calculations.

In the 70th percentile residential and commercial load forecasts, temperatures in each month were assumed to be at the 70th percentile of HDD in winter and at the 70th percentile of CDD in the summer. In the 70th percentile irrigation load forecast, GDD were assumed at the 70th percentile and precipitation was assumed to be at the 70th percentile, reflecting weather that is both hotter and drier than median weather. The 90th percentile irrigation load forecast was similarly constructed using weather values measured at the 90th percentile.

Idaho Power's total load is highly dependent upon weather. The three scenarios allow careful examination of load variability and how the load variability may impact resource requirements. It is important to understand the probabilities associated with the load forecasts apply to any given month and an extreme month may not necessarily be followed by another extreme month. In fact, a typical year likely contains some extreme months as well as some mild months.

Weather conditions are the primary factor affecting the load forecast on the hourly, daily, weekly, monthly, and seasonal time horizon. Economic and demographic conditions affect the load forecast over the long-term horizon.

Micron Technology

Micron Technology is currently Idaho Power's largest individual customer. In the 2006 IRP forecast, electricity sales to Micron Technology are expected to steadily rise throughout the forecast period. The primary driver of long-term electricity sales growth at Micron Technology is employment growth in the Electronic Equipment sector as provided by the 2006 Economic Forecast. Presently, Micron's load is approaching 80 aMW.

Idaho National Laboratory

The Idaho National Laboratory (INL) is a U.S. Department of Energy (DOE) research facility located in eastern Idaho. The INL is operated for the DOE by Battelle Energy Alliance, LLC which includes the Battelle Memorial Institute teamed with several institutions including BWXT Services Inc., Washington Group International, the Electric Power Research Institute, and the Massachusetts Institute of Technology. The laboratory employs about 8,000 people. Historically, INL has operated several experimental nuclear reactors and generated a significant portion of its energy needs. Today, the laboratory is a special contract customer of Idaho Power with an average load of around 20 aMW and a peak-hour demand of nearly 40 MW.

Simplot Fertilizer

The Simplot fertilizer plant is the largest producer of phosphate fertilizer in the western United States. In August 2002, Simplot closed the ammonia production facility and the ammonia is now purchased from an outside suppler. Electricity usage at the Simplot facility is expected to increase at a very slow rate of growth in the future. Employment in the Chemical and Allied Products sector is the primary indicator used to forecast the use of electricity at the Simplot fertilizer plant.

Firm Sales Contracts

Idaho Power currently has two firm sales contracts. The contracts, expiration dates, and 2006 average load are shown in Table 3-3.

The contract with Raft River Rural Electric Cooperative expires on September 30, 2006. However, the Raft River Cooperative may renew the agreement on a year-to-year basis for five additional one-year terms which would extend service until September 30, 2011. The load forecasts in the 2006 IRP assume that Idaho Power will continue to serve the Raft River Cooperative contract over the entire planning period (2006–2025). However, the 2008 IRP will assume the contract is not extended beyond September 30, 2011. Idaho Power anticipates that the contract with the City of Weiser will not be renewed and is, therefore, not included in the forecast period after 2006.

Table 3-3. Firm Sales Contracts

Contract	Expiration	2006 Average Load
City of Weiser (Idaho)	Dec. 31, 2006	6 aMW
Raft River Rural Electric Cooperative (Nevada)	Sept. 30, 2006	6 aMW
Total Firm Sales		**12 aMW**

Idaho Power will continue to evaluate the value of firm sales contracts in the future. With the exception of the Raft River Cooperative contract, Idaho Power has not included the renewal of any term off-system sales contracts in its load forecast.

Hydro Forecast

The representative hydrologic conditions used for analysis in the 2006 IRP (the 50th, 70th, and 90th percentiles) are based on a computed hydrologic record for the Snake River Basin from 1928–2002. The historical record has been developed by the Idaho Department of Water Resources (IDWR) for the purpose of obtaining a hydrologic period of record of sufficient length to validate probability-based decisions. For example, a median (50th percentile) hydrologic condition based on a 75-year hydrologic period of record is generally considered more representative of true median conditions than the condition derived from a 50-year period of record. Table 3-4 shows the April through July Brownlee inflow history since 1993. The data reported in Table 3-4 indicate in six of the recent years the Brownlee inflows were at or below the 70th percentile planning criterion, and in two of those years, 1994 and 2001, the flows were at or below the 90th percentile planning criterion.

Table 3-4. Recent Brownlee Inflow History

Year	April–July Brownlee Inflow (MAF)	Rank	Worse than 70th Percentile Planning Criterion	Worse than 90th Percentile Planning Criterion
1993	6.1	0.36		
1994	2.6	0.93	X	X
1995	6.8	0.30		
1996	8.4	0.15		
1997	9.9	0.04		
1998	9.0	0.13		
1999	8.0	0.21		
2000	4.4	0.59		
2001	2.4	0.95	X	X
2002	3.2	0.78	X	
2003	3.6	0.73	X	
2004	3.1	0.82	X	
2005	3.6	0.72	X	

Water management facilities, irrigation facilities, and operations in the Snake River Basin changed greatly during the 20th Century. Therefore, for a hydrologic record to be meaningful from a planning perspective, the hydrologic record should reflect the current level of development in the Snake River Basin. The process followed by IDWR in developing the hydrologic record involves modifying the actual historical record to account for development, present baseflow, current system operations, and existing facilities. For example, prior to the late 1940s, the primary irrigation method used was flood irrigation. Since the early 1900s, the construction of storage reservoirs and canal systems in southern Idaho has led to less water in the Snake River. Over the past 50 years, there has also been a significant conversion from flood to sprinkler irrigation, and from surface-supplied irrigation to groundwater-supplied irrigation. There has also been a significant additional amount of groundwater-irrigated land put into production over the past 50 years resulting in reduced spring-fed contributions to the river. As a result of these changes over the years, the natural flow hydrograph has been altered. The timing and volume of the natural flow, in the river and from the springs, has changed. The changes are built into IDWR's standardized hydrologic record (1928–2002), which is produced by IDWR's depleted flow model, to reflect today's system. Idaho Power uses the IDWR standardized hydrologic record, plus actual flows for 2003 and 2004, in the hydro generation modeling performed for its Integrated Resource Plan.

Part of the process by which the historical record is standardized involves adjusting the actual flows to a level of baseflow that is representative of the conditions existing today. Baseflow is defined as that portion of streamflow derived primarily from groundwater seepage into the stream channel. Observed records suggest that baseflow in the Snake River, particularly between Idaho Power's Twin Falls and Swan Falls projects, has been declining for several decades. The yearly average flow measured below Swan Falls has declined at an average rate of 53 cubic feet per second (cfs) per year from 1960–2005. In addition, observed streamflow gains between Twin Falls and Lower Salmon Falls, which are largely attributed to baseflow contribution, have declined at a rate of 29 cfs/year over the same period. A decrease of 53 cfs per year represents the loss of over 38,400 acre-feet of water per year, and a hydro generation loss of approximately 153 aMW in 2005 as compared to 1960. If the trend continues, the reduction in hydro generation due to declining baseflow may reach 183 aMW by 2015.

The observed decline, which continues today, is due to consumptive groundwater withdrawals and has been exacerbated by recent drought conditions. Since the 2004 IRP, IDWR has updated its standardized hydrologic record to reflect the present condition of the Snake River Basin as based on data through September 2002. The previous version of the hydrologic record used for the 2004 IRP assumed a present condition as based on data through September 1992. The updated record more accurately reflects the decreased baseflow in the river system. As an example, the assumed annual average streamflow gain between Twin Falls and Lower Salmon Falls for the period 1928–1992 was 5,260 cfs in the previously used IDWR hydrologic record, and is only 4,790 cfs in the newly updated version. The results mean that the present condition assumed by IDWR for the Twin Falls to Lower Salmon Falls reach gain, which is largely attributed to baseflow contribution, has declined on an annual average basis by approximately 470 cfs because of changes in basin hydrology observed from 1992–2002. The 470 cfs decline translates to a hydro generation loss of 25–30 aMW on an annual basis. In large part because of the changing nature of the Snake River Basin's hydrologic characteristics, IDWR has expressed its intent to update the standardized record more frequently in the future. The updates will be critical in ensuring that the standardized record continues to reflect present Snake River Basin conditions, and the hydro generation levels computed under the various hydrologic conditions are consistent with the associated probabilities assumed in Idaho Power's Integrated Resource Plans.

Generation Forecast

The generation forecast includes existing and committed resources. The output from the two committed resources, the Danskin addition (170 MW available in 2008), and the Shoshone Falls upgrade (49 MW available in 2010) are included in Idaho Power's generation forecast.

Scheduled and forced outages are also incorporated in the forecast using historical data. Idaho Power used planned maintenance and traditional maintenance schedules to estimate scheduled outages. Forced outages were estimated using observed forced outage rates at the various facilities randomly assigned throughout the planning period. The hydro facility generation is directly related to the hydro forecast discussed earlier.

Transmission Forecast

Transmission constraints are an important factor in Idaho Power's ability to reliably serve peak-hour load conditions. Off-system spot market purchases are the last resort Idaho Power employs when its generating resources and firm purchases are inadequate to meet peak-hour load requirements. The transmission constraints on Idaho Power's system limit its ability to import off-system market purchases during certain seasons and system conditions.

The transmission analysis requires hourly forecasts for the entire 20-year planning period for loads and generation levels on Idaho Power's system. The hourly transmission analysis is used to quantify the magnitude of off-system market purchases that may be required to serve the load, and determine if there will be adequate transmission capacity available to deliver the off-system purchases to the load centers.

From the hourly load and generation forecasts, a determination can be made regarding the need for, and magnitude of, off-system market purchases needed to serve system load. The projected off-system market purchases are summed with all other committed transmission obligations to determine if the resulting transmission load will exceed the operational limits of Idaho Power's transmission constraints.

The analysis assumes all off-system market purchases will come from the Pacific Northwest. Historically, during Idaho Power's peak-hour load periods, off-system market purchases from other areas have often times proven to be unavailable or very expensive. Many of the utilities to the east and south of Idaho Power also experience a summer peak, and the weather conditions that drive the summer peak are often similar across the Intermountain and Rocky Mountain West.

Idaho Power believes it would not be prudent to rely on imports from the Rocky Mountain region for planning purposes.

Three different hydro generation/load scenarios are considered in the transmission analysis:

1. Median water / median load / 90th percentile peak-hour load

2. Seventieth percentile water and 70th percentile load / 95th percentile peak-hour load

3. Ninetieth percentile water and 70th percentile load / 95th percentile peak-hour load

The results of the 90th percentile water, 70th percentile load, and 95th percentile peak-hour load case are given the most weight in the transmission adequacy analysis, since this is the most extreme of the three scenarios.

One difficulty with transmission planning is while transmission resources are owned by a specific entity, they can be utilized by other parties due to the FERC's open access requirements. Idaho Power must reserve the use of its own transmission resources under open access as well. Often, Snake River flow forecasts for the rest of the year are not known with a high degree of accuracy until May or June. By that time it is potentially too late to acquire firm transmission capacity for the summer months.

Because of generation and transmission capacity concerns, Idaho Power believes the 95th percentile peak-hour load planning criterion is appropriate for the transmission analysis. The 95th percentile peak-hour load planning criterion means that there is a one-in-twenty chance Idaho Power will be required to initiate more drastic measures such as curtailing load if attempts to acquire energy and transmission access from the east and south markets are unsuccessful.

The results of the transmission analysis using 90th percentile water, 70th percentile load, and 95th percentile peak-hour load scenario were used to establish a capacity target for planning purposes. The capacity target identifies the amount of internal generation, demand-side programs, or transmission resources that must be added to Idaho Power's system to avoid capacity deficits.

Fuel Price Forecasts

Coal Price Forecast

The IRP expected coal price forecast is an average of Idaho Power's coal forecasts for its Valmy and Jim Bridger thermal plants. In addition, the IRP used a Wyoming-specific coal forecast for use in modeling prices for a resource located in Wyoming and a regional coal price forecast for a non-location specific, regional coal resource. The coal price forecasts were created using current coal and rail transportation market information, private forecasts, and the Global Insight 2006 U.S. Power Outlook report. The resulting costs in dollars-per-MMBTU represent the delivered cost of coal, including rail costs, coal costs, and use taxes. A summary of each of the coal price forecasts can be found in *Appendix D-Technical Appendix*.

Natural Gas Price Forecast

Idaho Power does not directly forecast natural gas prices; instead it combines industry forecasts developed by outside consultants as well as forecasts from published sources. The IRP expected gas price forecast is derived from public and private source forecasts including IGI Resources, NYMEX, PIRA, EIA, NWPCC, and U.S. Power Outlook. All source forecasts are converted to nominal dollars and then converted to dollars-per-MMBTU at the Sumas trading hub. Each source forecast is given a weight and included in a total weighted average in order to forecast Sumas dollars-per-MMBTU. Transportation costs are then added to the weighted average price to develop a delivered Sumas price in dollars-per-MMBTU. The transportation costs also include Northwest Pipeline's fixed and volumetric charges as well as fuel gas.

The IRP high gas price forecast was derived by trending the NYMEX and IGI Resource forecasts for the period 2006–2009. This data was then trended from 2009–2013 to achieve a $1.00/MMBTU increase over the NWPCC high case starting in 2014 and thereafter. The IRP low gas price forecast was derived using the 2004 IRP expected case gas price forecast. Fuel forecast values are included in *Appendix D–Technical Appendix*.

4. Future Requirements

Idaho Power has an obligation to serve customer loads regardless of hydrologic conditions. In the past, when water conditions were at low levels, Idaho Power relied on market purchases to serve customer loads. Historically, Idaho Power's plan was to acquire or construct resources to eliminate expected energy deficiencies in every month of the forecast period whenever median or better water conditions existed, recognizing when water levels were below median, it would rely on market purchases to meet any deficits. When water levels were greater than median, Idaho Power would sell the surplus power in the regional markets.

In connection with the market price movements to historical highs during the energy crisis of 2000 and 2001, Idaho Power reevaluated the planning criteria as part of preparing the 2002 IRP. The public, the IPUC, and the Idaho Legislature all suggested Idaho Power placed too great a reliance on market purchases based upon the IRP planning criteria. Greater planning reserve margins or the use of more conservative water planning criteria were suggested as methods requiring Idaho Power to acquire more firm resources and reduce reliance on market purchases during low water years.

Water Planning Criteria for Resource Adequacy

Beginning with the 2002 IRP, Idaho Power specified a resource adequacy standard requiring new resources be acquired at the time the resources are needed to meet forecasted energy growth, assuming a water condition at the 70th percentile for hydroelectric generation. The 70th percentile means Idaho Power plans generation based on a level of streamflow that is exceeded in seven out of ten years on average. Streamflow conditions are expected to be worse than the planning criteria in three out of ten years, or 30 percent of the time. The 2006 IRP is the third resource plan wherein Idaho Power is using the 70th percentile water and 70th percentile average load conditions for energy planning.

Using the 70th percentile water planning criterion produces surpluses whenever streamflows are greater than the 70th percentile. Temporary off-system sales of surplus energy and capacity provide additional revenue and reduce the costs to Idaho Power customers. During months when Idaho Power faces an energy or capacity deficit because of low streamflow, excessive demand, or for any other reason, it plans to purchase off-system energy

Highlights

- Idaho Power uses 70th percentile average load and 70th percentile water conditions for energy planning.
- For peak-hour capacity planning, Idaho Power uses 90th percentile water conditions and 95th percentile peak-hour loads.
- Peak-hour load deficiencies are greater than 500 MW by 2011, and approximately 1,800 MW by 2025.
- The lack of available transmission capacity limits Idaho Power's ability to import additional energy during the summertime.
- Idaho Power currently maintains a capacity reserve margin of approximately 11%.

and capacity on a short-term basis to meet system requirements.

During the summer peak periods, low water conditions are more problematic than are high load conditions. The variability around the summer peak load is considerably less than the variability associated with water conditions. For example, April–July Brownlee inflow can range from under two million acre-feet to just over 11 million acre-feet. Summer high temperatures range from 98–111 degrees, meaning hot summer temperatures are more certain than are water conditions and low water conditions are likely to be the more significant planning factor.

Low water scenarios have been evaluated and included in the 2006 IRP to demonstrate the viability of Idaho Power's plan to serve average and peak loads under low water conditions. Low water conditions are defined with the 90^{th} percentile meaning Idaho Power can expect the low water conditions to occur in one out of ten years. The evaluations also include consideration of Idaho Power's transmission capability at times of lower streamflows.

The water planning criterion used by other utilities in the Pacific Northwest varies from median or 50^{th} percentile conditions to extreme or critical water conditions. Critical water conditions are generally defined to be the worst, or nearly worst, annual water conditions ever experienced based on historical streamflow records. Idaho Power utilizes a 70^{th} percentile water planning criterion which is more conservative that median conditions, but less conservative when compared to critical water conditions. A summary of other Pacific Northwest utility planning criteria is included in *Appendix D–Technical Appendix*.

Transmission Adequacy

Historically, Idaho Power has been able to reasonably plan for the use of short-term power purchases to meet temporary water related generation deficiencies on its own system. Short-term power purchases have been successful because Idaho Power is a summer-peaking utility while the majority of other utilities in the Pacific Northwest region experience peak loads during the winter.

The transmission adequacy analysis reflects Idaho Power's contractual transmission obligations to provide wheeling service to the BPA loads in southern Idaho. The BPA loads are typically served with a combination of energy and capacity from the Pacific Northwest and several BOR projects located in southern Idaho. The contractual transmission obligations are detailed in four Network Service Agreements under the Idaho Power Open Access Transmission Tariff.

Although Idaho Power has transmission interconnections to the Southwest, the Pacific Northwest market is the preferred source of purchased power. The Pacific Northwest market has a large number of participants, high transaction volume, and is very liquid. The accessible power markets south and east of Idaho Power's system tend to be smaller, less liquid, and have greater transmission distances. In addition, the markets south and east of Idaho Power's system can be very limited during summer peak conditions.

Recent history has shown even when power is available from the Pacific Northwest market, short-term prices can be quite high and volatile. The price risk has led to the development of the Energy Risk Management Policy discussed in Chapter 1. The Energy Risk Management Policy represents the collaboration of Idaho Power, the IPUC staff, and interested customers in Commission Case IPC-E-01-16.

Prior to 2000, Idaho Power's IRPs often emphasized acquisition of energy rather than construction of generating resources to satisfy load obligations. Transmission limitations were not a major impediment to Idaho Power's purchasing power to meet its service obligations. Idaho Power recognized transmission constraints began to place limits on purchased power supply strategies starting with the 2000 IRP. To better assess power supply requirements and available transmission, the 2006 IRP contains an analysis of transmission system constraints for the 20-year planning period. (See Chapter 2)

Planning Reserve Margin

In the past, the Western Electricity Coordinating Council (WECC) required Idaho Power to maintain 330 MW of reserves above the forecast peak-hour load to cover the worst single planning contingency which was defined to be an unexpected loss equal to Idaho Power's share of two Jim Bridger generation units. At present, the WECC has dropped the planning reserve requirements. However, the North American Electric Reliability Council has approved measures requiring the WECC to reinstate some form of planning reserve requirements. Idaho Power will continue meeting the historical WECC planning reserve requirements under any planning scenario until new planning requirements are established. Idaho Power's record peak-hour load is 3,084 MW, which means the current, self-imposed reserve requirement of 330 MW is equal to a reserve margin of approximately 11 percent.

The future resource requirements of Idaho Power are not based directly on the need to meet a specified reserve margin. Idaho Power's long-term resource planning is instead driven by the objective to develop resources sufficient to meet higher than expected load conditions under lower than expected water conditions which effectively provides a reserve margin. As a part of preparing the 2006 IRP, Idaho Power has calculated the capacity reserve margin resulting from the resource development identified in the preferred portfolio. In this process, the total resources available to meet demand consist of those made available under the preferred portfolio plus generation from existing and committed resources assuming expected water conditions. The generation from existing resources also includes expected firm purchases contracted with surrounding regional markets. The resource total is then compared with expected peak-hour loading, with the excess resource designated as reserve margin. This provides an alternative view of the adequacy of the preferred portfolio, which was developed to meet more stringent load conditions under less favorable water conditions. Capacity reserve calculations for each year throughout the planning period are included in *Appendix D–Technical Appendix*.

Salmon Recovery Program and Resource Adequacy

The December 1994 amendments to the Northwest Power Planning Council's fish and wildlife program and the biological opinions issued under the ESA for the four lower Snake River federal hydroelectric projects call for 427,000 acre-feet of water to be acquired by the federal government from willing lessors upstream of Brownlee Reservoir. The acquired water is then to be released during the spring and summer months to assist ESA-listed juvenile salmonids (spring, summer, and fall chinook and steelhead) migrating past the four federal hydroelectric projects on the lower Snake River. In the past, water releases from Idaho Power's hydroelectric generating plants have been modified to cooperate with the federal efforts. Idaho Power also adjusts flows in the late fall of each year to assist with the spawning of fall chinook below the Hells Canyon Complex.

Because of the practical, physical, and legal constraints federal interests must deal with in moving 427,000 acre-feet of water out of Idaho, in the past Idaho Power has pre-released, or shaped, a portion of the acquired water with water from Brownlee Reservoir and later refilled the reservoir with water leased under the federal program. At times, Idaho Power has also contributed water from Brownlee Reservoir to assist with the federal efforts to improve salmon migration past the federal government's lower Snake River projects.

Planning Scenarios

The timing and necessity of future generation resources are based on a 20-year forecast of surpluses and deficiencies for monthly average load (energy) and peak-hour load. For both of these areas, one set of criteria has been chosen for planning purposes; however, additional scenarios have been analyzed to provide a comparison. Table 4-1 provides a summary of six planning scenarios analyzed for the 2006 IRP and the criteria used for planning purposes are shown in bold. Median water and median load forecast scenarios were included to enable comparison of the 2006 IRP with plans developed during the 1990s. The median forecast is no longer used for resource planning, although the median forecast is used to set retail rates and avoided-cost rates during regulatory proceedings. The planning criteria used to prepare Idaho Power's 2006 IRP is consistent with the criteria used in the 2004 Integrated Resource Plan.

Table 4-1. Planning Criteria for Average Load and Peak-Hour Load

Average Load/Energy (aMW)
50th Percentile Water, 50th Percentile Average Load
70th Percentile Water, 70th Percentile Average Load
90th Percentile Water, 70th Percentile Average Load
Peak-Hour Load (MW)
50th Percentile Water, 90th Percentile Peak-Hour Load
70th Percentile Water, 95th Percentile Peak-Hour Load
90th Percentile Water, 95th Percentile Peak-Hour Load

The planning criteria used for energy or average load are 70th percentile water and 70th percentile average load. In addition, 50th percentile water and 50th percentile average load conditions are analyzed to represent a median condition, and 90th percentile water and 70th percentile average load are analyzed to examine the effects of low water conditions.

Peak-hour load planning criteria consist of 90th percentile water and 95th percentile peak-hour load conditions, coupled with Idaho Power's ability to import additional energy on its transmission system. A median condition of 50th percentile water and 50th percentile peak-hour load are also analyzed, as well as 70th percentile water and 95th percentile peak-hour load. Peak-hour load planning criteria are more stringent than average load planning criteria because Idaho Power's ability to import additional energy is typically limited during peak-hour load periods.

Surpluses and deficiencies for the average and peak-hour load scenarios used for planning purposes can be found in Figures 4-1 and 4-2. Surpluses and deficiencies for the scenarios not used for planning purposes can be found in *Appendix D–Technical Appendix*.

Average Load (Energy)

The planning criteria for determining the need for energy resources assumes 70th percentile water and 70th percentile average load conditions. In purely statistical terms, if the two probabilities—average load and hydrological conditions—are independent, then one of the two conditions—either poor water conditions or high average load conditions—can be expected in about half of the years.

Figure 4-1 indicates under 70th percentile water and 70th percentile average load conditions, energy deficiencies occur in July 2006 (35 aMW) and July 2007 (88 aMW). These initial deficiencies are due to the postponement of the 170 MW natural gas-fired unit at the Danskin Project. This new unit, which was identified in the 2004 IRP and was originally scheduled to come on-line in April 2007, is now expected to be operational by April 2008. Long-term summer deficiencies begin in July 2009 at 15 aMW and are expected to grow to 859 aMW by July 2025.

Figure 4-1. Monthly Energy Surplus/Deficiency
70th Percentile Water, 70th Percentile Average Load
(Existing and Committed Resources)

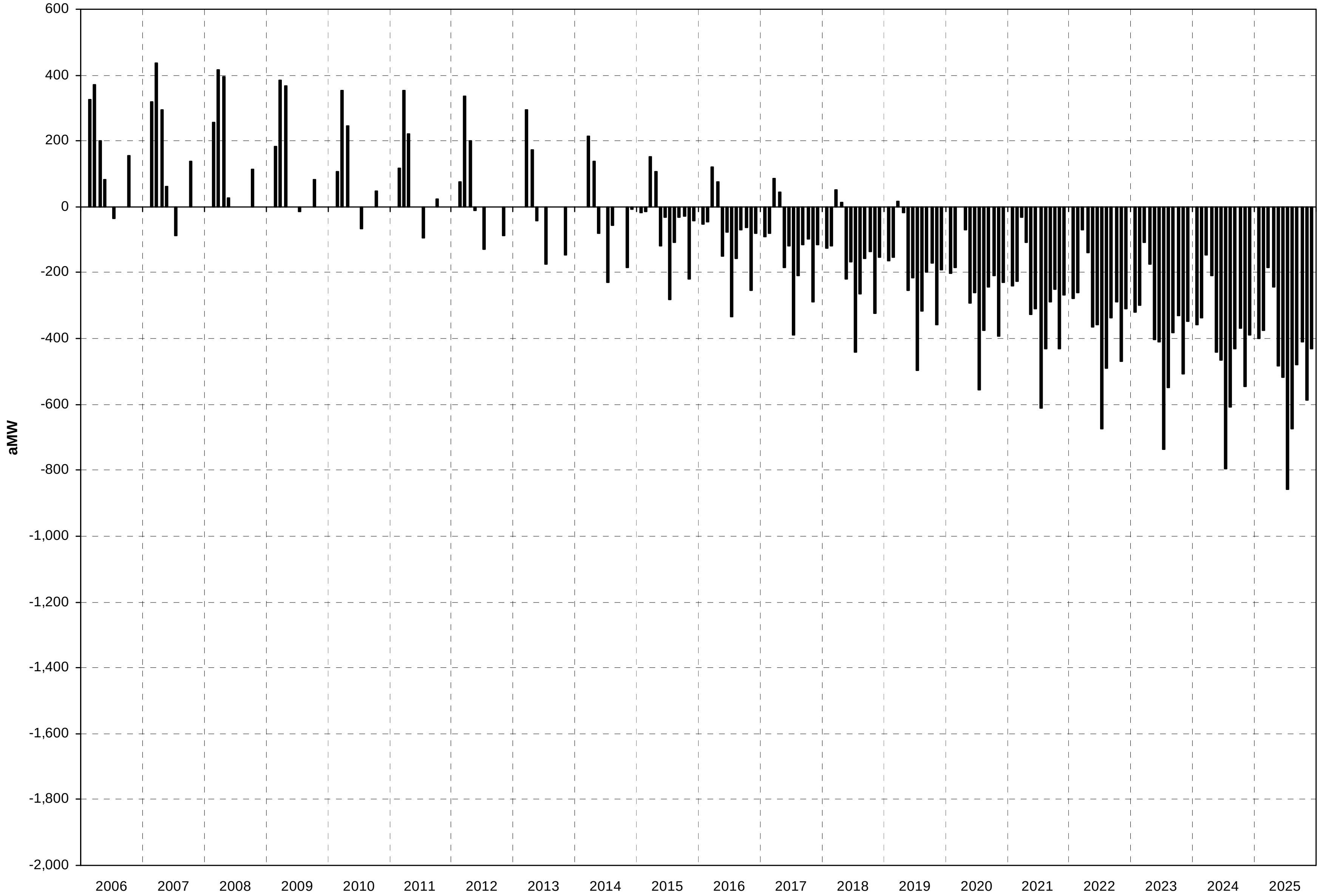
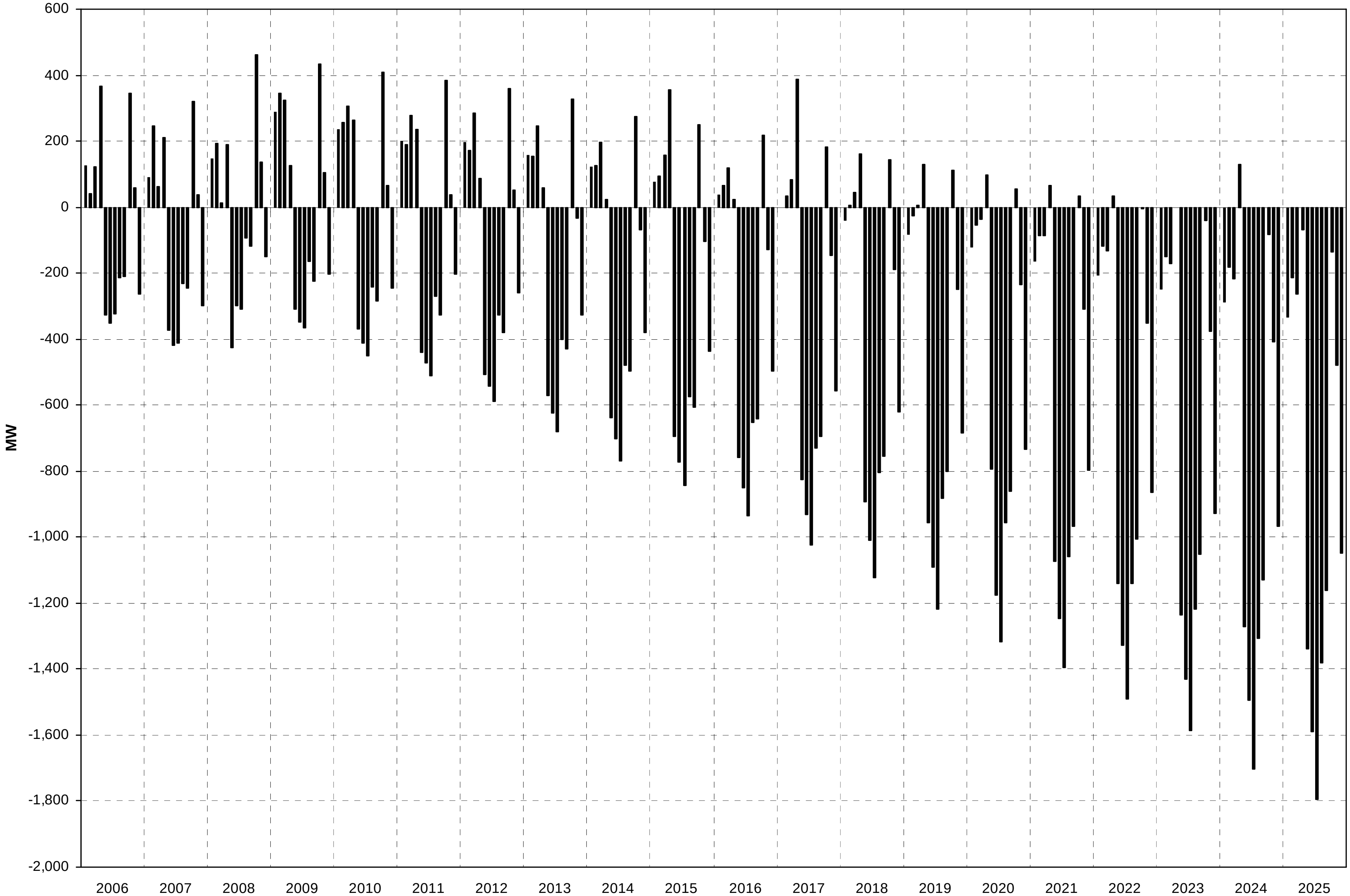


Figure 4-2. Monthly Peak-Hour Surplus/Deficiency
90th Percentile Water, 95th Percentile Peak Load
(Existing and Committed Resources)



A wintertime deficiency of 87 aMW occurs in November 2012 due to Idaho Power's cooperative effort to pass water for salmon migration. Under the assumption Idaho Power will continue to adjust flows in the Hells Canyon Complex to aid salmon migration, the deficiencies in November are expected to continue to grow throughout the planning period to 586 aMW in November 2025. Deficiencies in December, which are more indicative of wintertime customer demand, start at 7 aMW in 2014 and grow to 430 aMW in 2025.

This analysis assumes Idaho Power's combustion turbines are in service and available to operate up to permitted limits. Although these turbines are available to meet monthly energy deficiencies, market purchases imported via the transmission system will most likely be the preferred alternative whenever transmission import capacity from the Pacific Northwest is available.

Peak-Hour Load

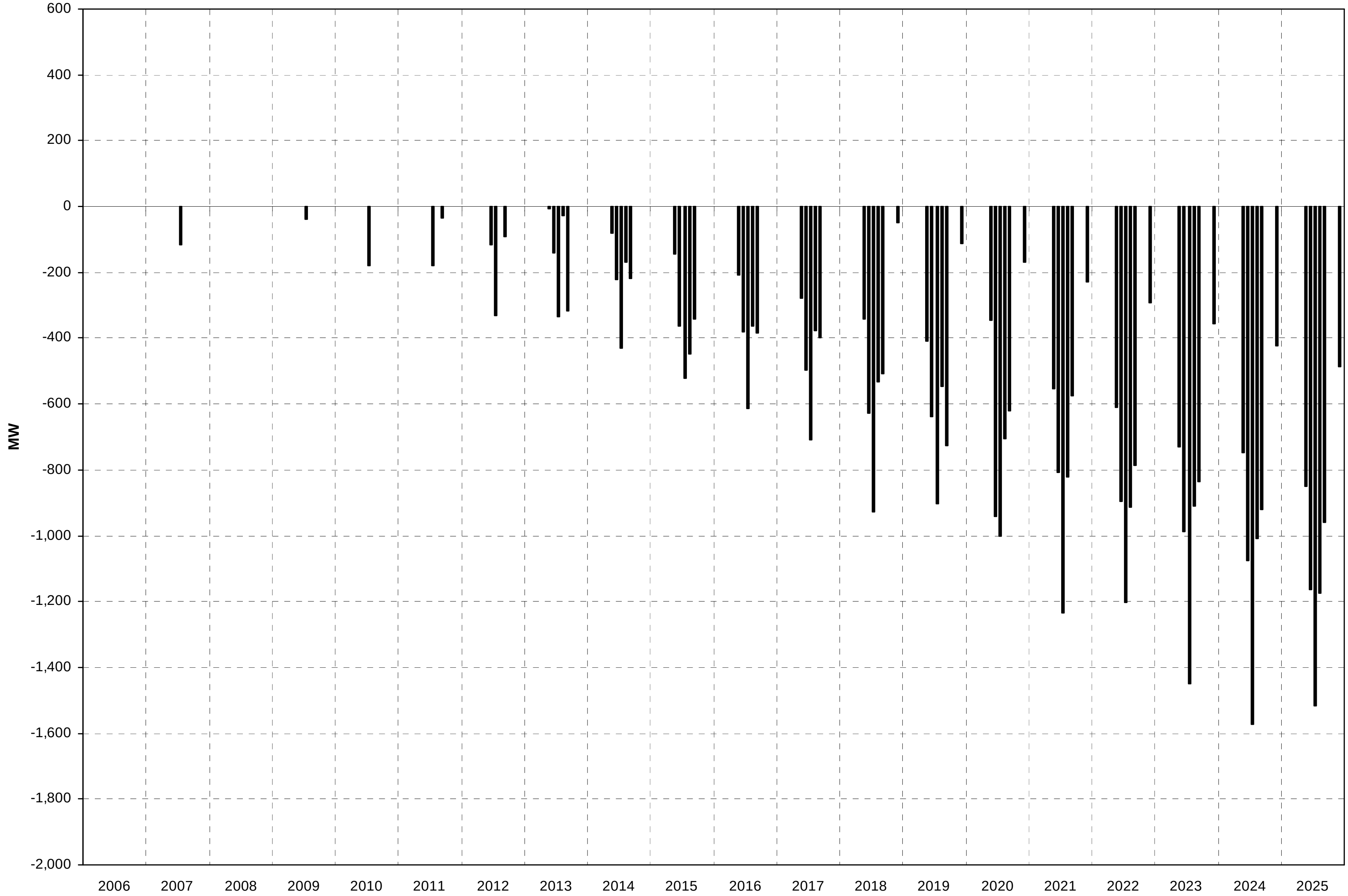
Peak-hour load deficiencies are determined using 90th percentile water and 95th percentile peak-hour load conditions, coupled with Idaho Power's ability to import additional energy on its transmission system to reduce any deficits. In addition to these criteria, 70th percentile average load conditions are assumed, but the hydrologic, peak-hour load and transmission constraint criteria are the major factors in determining the peak-hour load deficiencies. Peak-hour load planning criteria are more stringent than average load criteria because Idaho Power's ability to import additional energy is typically limited during peak-hour load periods.

Figure 4-2 indicates under 90th percentile water and 95th percentile peak-hour load conditions, deficiencies exist during summer months throughout the planning period. Summer deficiencies from 2006–2010 remain between 350 to 400 MW due to the addition of the natural gas unit at the Danskin Project in April 2008 and the expansion of the Shoshone Falls Project in 2010. For the remainder of the planning period, deficiencies in July increase from 450 MW to 1,800 MW in 2025.

Figure 4-3 indicates the amount of the peak-hour deficit (identified in Figure 4-2) that cannot be imported from the Pacific Northwest over the existing transmission system under 90th percentile water and 95th percentile peak-hour load conditions. The remaining deficiencies shown in Figure 4-3 also account for a reserve margin of 330 MW as previously discussed.

In this analysis, a deficiency exists in July 2007 due to the postponement of the 170 MW natural gas-fired unit at the Danskin Project. Beginning in 2009, long-term transmission deficiencies occur in summer months and are expected to grow to approximately 1,550 MW by 2025.

Figure 4-3. Monthly Peak-Hour Northwest Transmission Deficit
90th Percentile Water, 95th Percentile Peak Load
(Existing and Committed Resources)



5. Potential Resource Portfolios

Resource Cost Analysis

The costs of a variety of supply-side, transmission, and demand-side resources were analyzed. Cost inputs and operating data used to develop the resource cost analysis were derived from various sources including the NWPCC, DOE, independent consultants, and regional energy project developers. Resource costs are presented as:

- Levelized fixed cost per kW of installed (nameplate) capacity per month, and
- Total levelized cost per MWh of expected plant output or energy saved, given assumed capacity factors and other operating assumptions.

The levelized costs for the various supply-side and transmission alternatives include the cost of capital, operating and maintenance (O&M) costs, fuel costs, and other applicable adders and credits. The cost estimates used to determine the cost of capital for the supply-side resources include engineering development costs, generating and ancillary equipment purchase costs, installation, applicable balance of plant construction, and the costs for a generic transmission interconnection to Idaho Power's network system. More detailed interconnection and transmission system backbone upgrade costs were estimated by Idaho Power's transmission planning group. These costs are included in Chapter 6 and summarized in Table 6-9. The cost of capital also includes Allowance for Funds Used During Construction (AFUDC–capitalized interest).

The O&M portion of each resource's levelized cost includes general estimates for property taxes and property insurance premiums. For the transmission plus market purchase alternatives, the levelized costs include assumed wholesale energy purchases at an estimated price of $60 per MWh.

The levelized costs for each of the demand-side resource options include annual administrative and marketing costs of the program, annual incentive or rebate payments, and annual participant costs. The demand-side resource costs do not reflect the financial impact to Idaho Power as a result of these load-reduction programs.

Highlights

- ► Based on the 30-year cost of production, geothermal resources and demand-side measures are the lowest cost resources, however transmission resources may be more attractive depending on the market price of power.
- ► Coal-fired generation falls in the middle of the resource cost list when considering either fixed-cost or operating costs.
- ► Simple-cycle combustion turbines continue to be the lowest cost peaking resource based on low fixed costs, however, SCCTs have high operating costs due to the low number of operating hours.
- ► Twelve different portfolios were initially analyzed in the 2006 IRP, each designed to explore a variety of different resource alternatives to meet forecasted energy and capacity needs.

Specific resource cost inputs, fuel forecasts, key financing assumptions, and other operating parameters are shown in *Appendix D–Technical Appendix.*

Emission Adders for Fossil Fuel-Based Resources

All resource alternatives have potential environmental and other social costs that extend beyond just the capital and operating costs included in the cost of electricity. Fossil fuel-based generating resources are particularly sensitive to some of these costs and impacts. It is likely that further emissions regulations will be implemented during the period covered in the 2006 Integrated Resource Plan.

In the analysis, Idaho Power incorporated estimates for the future costs of certain emissions into the overall cost of the various fossil fuel-based resources. Within the resource cost analysis ranking, the levelized costs for the various fossil fuel-based resources include emission adders for carbon dioxide (CO_2), nitrogen oxides (NO_x), and mercury. These additional costs are assumed to begin in 2012. Table 5-1 provides the emission adder rates assumed in the analysis. Based on these assumptions, Table 5-2 provides the emissions cost per MWh for the various fossil fuel-based resources that were analyzed. Emission adders, specifically for CO_2 are discussed further in Chapter 6.

Table 5-1. Emissions Adders for Fossil Fuel Generating Resources–Base Case

Adder	Cost in 2006 U.S. dollars	First Year Applied	Annual Escalation
CO_2	$14 per ton	2012	2.26%
NO_x	$2,600 per ton	2012	2.26%
Mercury	$1,443 per ounce	2012	2.26%

Table 5-2. Emission Adders–Dollars per MWh (2006 Dollars)–Base Case

Adder	CO_2	NO_x	Hg	Total
Pulverized Coal	$12.26	$0.37	$0.46	$13.08
IGCC	$11.69	$0.60	$0.46	$12.75
IGCC with Carbon Sequestration	$1.76	$0.31	$0.46	$3.21
Fluidized Bed Coal	$12.26	$0.87	$0.46	$13.59
Simple-Cycle CT	$7.93	$0.10	$0.00	$8.03
Combined-Cycle CT	$5.60	$0.00	$0.00	$5.60

Production Tax Credits for Renewable Generating Resources

Various federal tax incentives for renewable-based generation were extended and/or renewed within the Energy Policy Act of 2005. This legislation requires most projects to be on-line by December 31, 2007, to be eligible for the federal production tax credits (PTCs) identified in Section 45 of the Internal Revenue Code. The credit is earned on power produced by the project during the first 10 years of operation. The credit, which is adjusted annually for inflation is currently valued at $19 per MWh for wind and geothermal resources.

Due to the uncertainty surrounding future extensions of federal PTCs, wind and geothermal resources are shown in the resource cost analysis ranking both with and without the PTC reflected in the overall levelized cost. For the portfolio valuation discussed later in Chapter 5, the PTC is assumed to be extended for projects that are on-line by the end of 2011. The federal PTC was not applied to geothermal and wind projects assumed to come on-line after 2011.

30-Year Nominally Levelized Fixed Cost per kW per Month

The annual fixed cost streams for each resource were summed and levelized over a 30-year operating life and presented as dollars per kW of plant nameplate capacity per month. Figure 5-1 provides a combined ranking of all the various resource options, in order of lowest to highest levelized fixed cost per kW per month. The ranking shows several of the transmission alternatives, DSM programs, and simple-cycle combustion turbine (SCCT) resources are the lowest capacity cost alternatives.

30-Year Nominally Levelized Cost of Production (Baseload and Peaking Service Capacity Factors)

Certain resource alternatives carry low fixed costs and high variable operating costs while other alternatives require significantly higher capital investment and subsequent fixed operating costs, but have very low variable operating costs. The levelized cost of production measurement represents the estimated annual cost per MWh for a resource based on some expected level of energy output.

The calculations were performed assuming two levels of annual energy output. First, the levelized cost of production is shown assuming expected baseload capacity factors (see Figure 5-2). Second, the levelized cost of production is shown assuming expected peaking service capacity factors (see Figure 5-3). Resources such as DSM measures, advanced nuclear, geothermal, wind, and certain types of thermal generation appear to be the lowest cost for meeting baseload requirements, while other resources like combustion turbines and transmission alternatives are lowest cost for meeting peaking requirements.

Resource Cost Analysis Results

Based on the 30-year cost of production, flashed steam geothermal resources and demand-side measures are the lowest cost resources; however, transmission resources may be more attractive, depending on the market price of power. Coal-fired generation falls in the middle of the list when considering either fixed-cost or operating costs.

SCCTs, similar to Idaho Power's Danskin and Bennett Mountain plants, are the lowest cost peaking resource based on low fixed costs. SCCTs do have high operating costs, but the operating costs are not as important when the resource is only used a limited number of hours per year to meet peak demand.

Supply-Side Resource Options

Included below are descriptions and characteristics of the various supply-side resource alternatives analyzed in the 2006 Integrated Resource Plan.

Wind

A typical wind farm consists of a widespread array of wind turbine generators ranging in size from 1–3 MW each. The majority of the potential wind sites in southern Idaho lie between the south-central and the most southeastern part of the state. Areas that receive consistent, sustained winds greater than 15 miles per hour are prime locations for wind development.

To date, southern Idaho has not proven to be as optimal for wind development from a meteorological perspective as some neighboring states; however, several hundred megawatts of wind generation have either been contracted since 2004 or are currently under development. The extension of the federal PTC has made the financial aspects of wind generation attractive and is a major reason substantial development is occurring. There is significant debate regarding the current stage of the industry, and uncertainty surrounding the future extension of tax incentives for wind generation. Without federal tax incentives, RPSs, a carbon adder or high gas prices, it may be several years before wind generation can consistently compete economically with other generation alternatives.

Figure 5-1. 30-Year Nominal Levelized Fixed Costs
Cost of Capital and Fixed Operating Costs

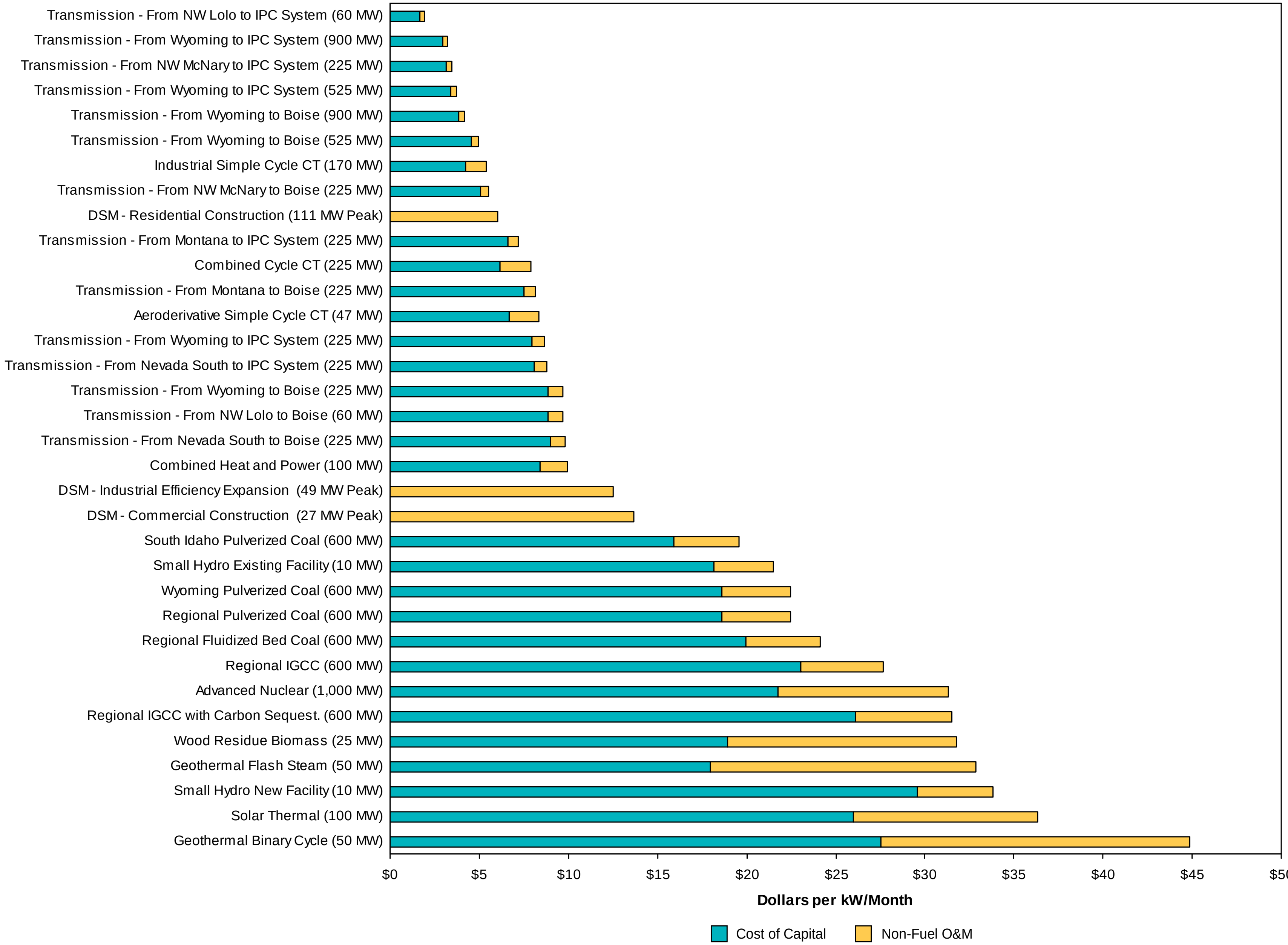


Figure 5-2. 30-Year Nominal Levelized Cost of Production at Baseload Capacity Factors

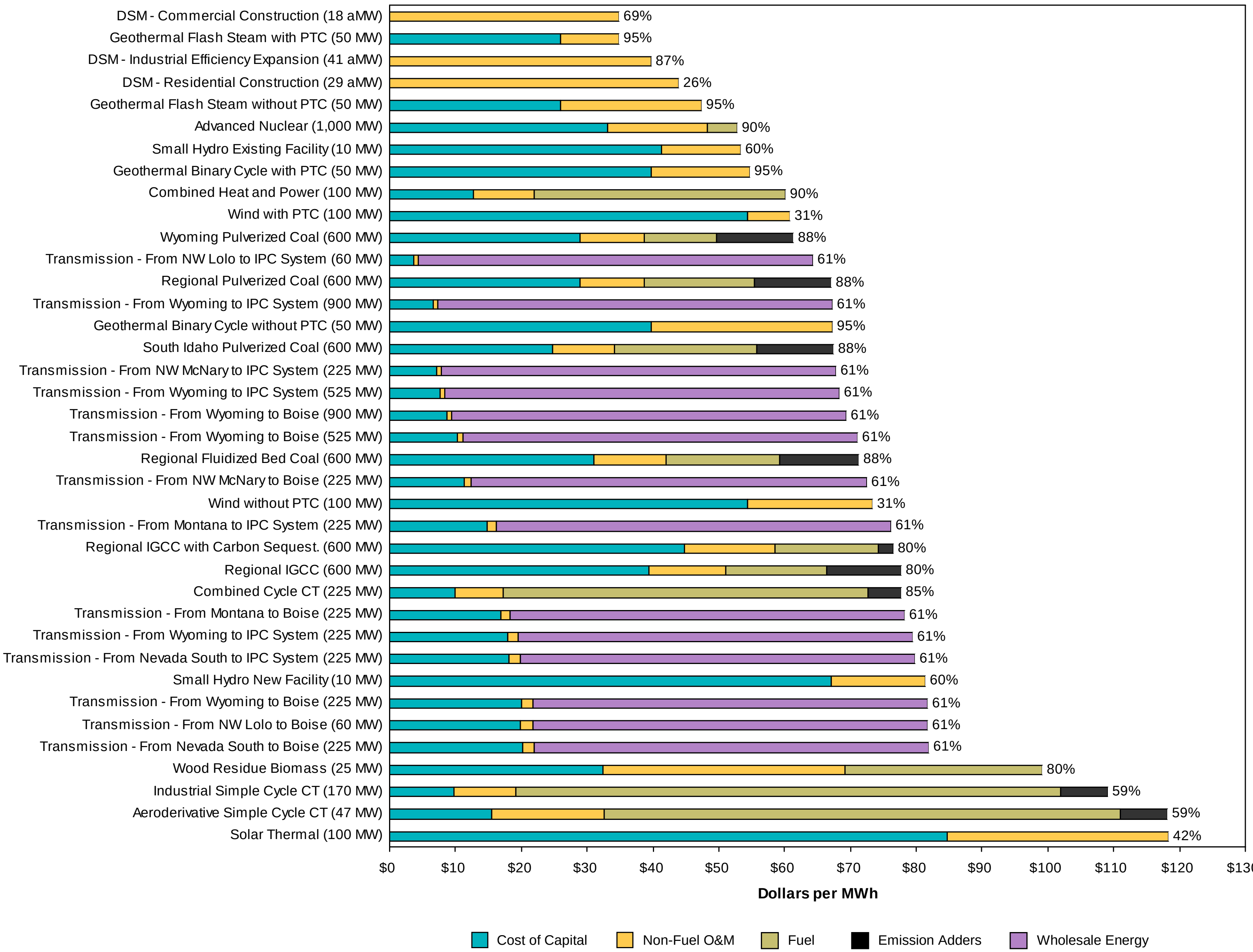
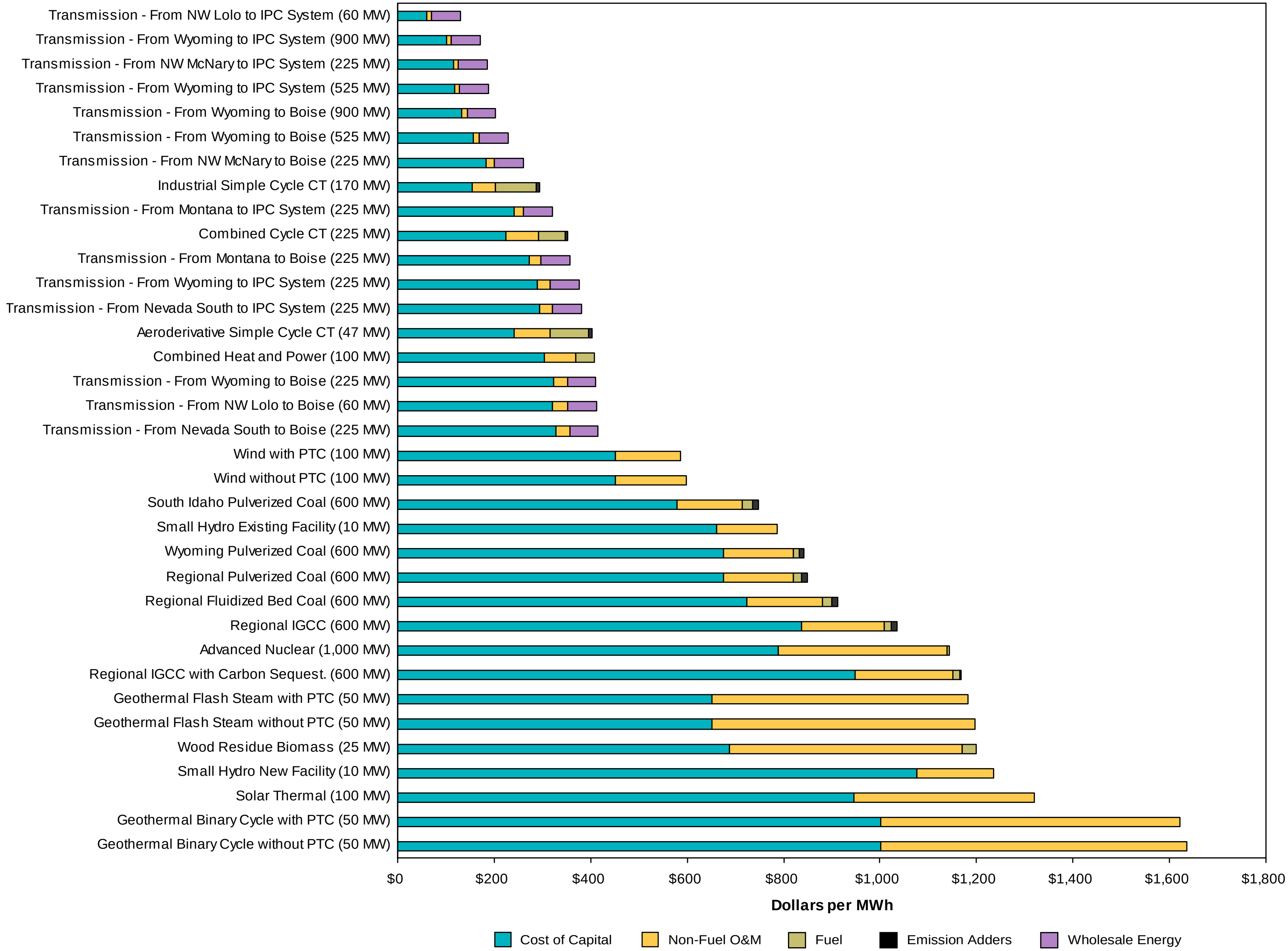


Figure 5-3. 30-Year Nominal Levelized Cost of Production at 4% Capacity Factors (Peaking Service)



In the 2006 IRP, Idaho Power has assumed the federal PTC will be extended in its current form for wind projects constructed and on-line by the end of 2011.

To estimate wind resource output, Idaho Power used a combination of data from wind developers and the NWPCC. Wind output was estimated for three time periods—annual, monthly, and hourly—during peak hours in July. The estimate used for annual energy output is based on a 31 percent capacity factor. The 31 percent capacity factor means that a wind project with a nameplate capacity of 100 MW will produce over 270,000 MWh, or an average of 31 aMW over the course of a year.

Monthly energy output was derived from the normalized monthly wind energy distribution for areas characterized as Basin and Range (which includes southern Idaho) in the NWPCC's wind resource characterization paper. The NWPCC distribution is included as part of *Appendix D–Technical Appendix*.

Estimated wind output during peak-hour loads in July is based on actual data provided by a wind developer for a specific Idaho project. The data indicate during July between the hours of 4 p.m. and 8 p.m., a 100 MW wind project will produce 5 MW or more 70 percent of the time. Based on wind data and the 70^{th} percentile planning criteria, Idaho Power assumes a 100 MW wind project would provide 5 MW of capacity during summertime peak-hour loads.

The cost estimates and operating parameters for wind generation in the 2006 IRP were based on data from the NWPCC's Fifth Power Plan (2005) and independent wind developers. Wind resources included in the resource portfolios are assumed to be located in south-central or southeastern Idaho and within 25 miles of Idaho Power's transmission system. All resource portfolios contain at least 100 MW (nameplate) of wind generation, and some resource portfolios have up to 500 MW of additional nameplate wind capacity over the 20-year planning period.

From Idaho Power's perspective, one of the largest unanswered questions is the cost of integrating wind resources. Depending on wind integrations costs, Idaho Power may increase or decrease the amount of wind generation included in the preferred portfolio.

Wind Advantages

- Renewable resource
- No fuel cost or associated risk
- No harmful emissions
- Low, variable operating costs
- Potentially provides green tags which could satisfy Idaho Power's obligations if an RPS is adopted by the federal government, the State of Idaho, or the State of Oregon

Wind Disadvantages

- Limited number of economically feasible sites in southern Idaho
- Intermittent and non-dispatchable resource
- Capital cost uncertainty and volatility
- Potential avian, cultural, and aesthetic impacts
- Uncertainty surrounding future tax incentives

Geothermal–Binary and Flash Steam Technologies

Potential commercial geothermal generation in the Pacific Northwest includes both flashed steam and binary cycle technologies. Based on exploration to date in southern Idaho, binary cycle geothermal development is more likely than flashed steam within Idaho Power's service area. Most of the optimal locations for potential geothermal development are believed to be in the southeastern part of the state. However, the potential for geothermal generation in southern Idaho is somewhat uncertain. In addition, the time required to discover and prove geothermal resource sites is highly variable and can take years or even decades.

The overall cost of a geothermal resource varies with resource temperature, development size, and water availability. Flash steam plants are applicable for geothermal resources where the fluid temperature is 300º Fahrenheit or greater. Binary cycle technology is used for lower temperature geothermal resources. In a binary cycle geothermal plant, geothermal liquid is brought to the surface using wells, and passed through a heat exchanger where the geothermal energy is transferred to a low boiling point fluid (the secondary fluid). The secondary fluid is vaporized and used to drive a turbine generator. After driving the generator, the secondary fluid is condensed and recycled through a heat exchanger. The secondary fluid is reused continuously in the binary cycle plant. The primary fluid (the geothermal water) is returned to the geothermal reservoir through injection wells.

Cost estimates and operating parameters for binary cycle geothermal generation in the IRP are based on data from independent geothermal developers and information from the Geothermal Energy Association. Estimates for flashed steam geothermal generation are based on data from the NWPCC's Fifth Power Plan (2005). Geothermal resources included in the various portfolios are assumed to be located in southeastern Idaho and within 25 miles of Idaho Power's transmission system. Potential generation studied in each of the various portfolios ranged from 50 MW up to 400 MW of additional geothermal capacity over the 20-year planning period.

Geothermal Advantages

- Renewable resource
- No harmful emissions
- Minimal fuel risk once the geothermal resource is located
- Low, variable operating costs
- Advertised high availability and capacity factor (90%+)
- Potentially provides green tags which could satisfy Idaho Power's obligations if an RPS is adopted by the federal government, the State of Idaho, or the State of Oregon

Geothermal Disadvantages

- Unproven generation resource in Idaho
- Significant capital and fixed costs
- Capital cost uncertainty and volatility
- High exploration costs
- Uncertainty surrounding future tax incentives

Pulverized Coal (Regional, Wyoming, and Southern Idaho)

Coal-fired generation is a mature technology and has been the primary source of commercial power production in the U.S. for many decades. Traditional pulverized coal plants have been a significant part of Idaho Power's generation mix since the early 1970s. Idaho Power currently has over 1,000 MW of pulverized coal generation in service. All of Idaho Power's pulverized coal generation is in neighboring states and is owned with other regional utilities. Opportunities exist to expand existing plants or develop new projects in the Pacific Northwest and Intermountain regions.

The coal-fired steam–electric plant uses coal that is ground into a dust-like consistency and burned to heat water and produce steam to drive a steam turbine generator. Emission controls at coal plants have become increasingly important in recent years and many units in the region have been upgraded to include the latest scrubber and low-NO_x burner technology to help reduce harmful emissions and particulates. Almost all new pulverized coal plants are built with emission control technology. Coal has the highest ratio of carbon to hydrogen of all the fossil fuels and unless CO_2 sequestration provisions are incorporated in the project design, all coal plants emit substantial amounts of CO_2 into the atmosphere.

Coal prices have declined or remained stable in recent years. Coal price stability combined with high gas prices and anticipated continued load growth in the region has made development of baseload coal resources economically attractive. Even though coal-fired power plants require significant capital commitments to develop, coal-fired resources take advantage of a low-cost fuel and provide reliable and dispatchable energy. Coal supplies are abundant in the Rocky Mountain west. The western coal supply is sufficient to fuel Idaho Power's existing plants and any new coal resources modeled in this plan for many years to come.

Because the State of Idaho has chosen not to opt into the Clean Air Mercury Rule (CAMR), a new plant would have to be sited in a neighboring state or an expansion at one of the existing regional plants could be made. Siting a coal resource in the areas where plants already exist such as western Wyoming and Montana provide the benefit of being much closer to the regional coal supply. Coal-fired generation plants such as the Jim Bridger facility can be developed at the mine-mouth to reduce or even eliminate fuel transportation costs. In addition, coal plant development in the coal reserve areas may provide the benefit of a timelier permitting and regulatory process than in jurisdictions where coal-fired development does not currently exist.

Three specific site options were considered in the resource cost analysis to evaluate the economic characteristics of coal-fired generation plants. The first option is a generic regional plant in a neighboring state to the east or southeast which would be fueled by either low-cost mine-mouth coal or railed coal, and also require significant transmission interconnection investment. The second siting option is a plant located in southern Idaho with the coal delivered by rail. This option would require significantly less transmission interconnection investment. The third siting option is the expansion of an existing pulverized coal plant in Wyoming that would be fueled by low-cost, mine-mouth coal and require significant transmission interconnection investment.

Cost estimates and operating parameters for pulverized coal generation in the 2006 IRP are based on data from an independent engineering firm. Potential generation in the various resource portfolios ranges from 250 MW up to 1,000 MW of additional pulverized coal capacity over the 20-year planning period.

Pulverized Coal Advantages

- Abundant, low-cost fuel
- Less price volatility than natural gas
- Proven and reliable technology
- Dispatchable resource
- Well-suited for baseload operations

Pulverized Coal Disadvantages

- Potential lack of public acceptance
- Significant particulate and gas emissions, particularly CO_2
- Potential financial risks associated with future CO_2 emissions
- Significant capital investment
- Long construction lead times
- Lengthy environmental permitting and siting processes

Advanced Coal Technologies (IGCC, CFB) and Carbon Sequestration

The Energy Policy Act of 2005 identifies substantial financial incentives for innovative advanced coal technologies anticipated to reduce greenhouse gas emissions and promote more efficient use of fossil fuel resources. A majority of the advanced coal technologies, such as IGCC, circulating fluidized bed (CFB), and carbon sequestration, are not in large scale commercial operation in the United States due to more affordable alternatives. In addition, many of the advanced coal technologies are unproven and have never been put into commercial operation. Nevertheless, the pursuit of large-scale commercial development of advanced coal energy resources is anticipated to increase in the coming years due to the prospect of a federal carbon tax and increasingly restrictive emission regulations.

An IGCC power plant is a combination of a gasification plant and a generation facility. The coal gasification technology uses pulverized coal which is fed into a gasifier to produce heat, hydrogen, carbon monoxide, and CO_2. The gases are cooled, chemically treated to remove some of the pollutants, and filtered to remove particulates and control air emissions. The coal gases are ultimately fired in a gas turbine similar to the combustion turbines used in natural gas-fired combined cycle power plants. The turbine exhaust gas is passed through a heat recovery system to produce steam and drive a steam turbine generator.

Coal gasification technology has been widely employed in the petrochemical industry for many years, but the technology has not been applied to large-scale electric generation in the United States. An IGCC power plant will require significant capital commitments because of the two-stage process requiring both a gasification facility and a combined-cycle power plant.

CFB power plants use a combustion technology that can be fired on coal, biomass, and other fuels. Fluidized beds suspend solid fuels on upward-blowing jets of air during the combustion process. The result is a turbulent mixing of gas and solids. The turbulence, much like a bubbling fluid, provides more effective chemical reactions and heat transfer.

Fluidized bed combustion reduces the amount of sulfur emitted in the form of SO_x emissions. Limestone is used to precipitate the sulfate during combustion, which also allows more efficient heat transfer from the boiler to the heat exchanger (usually water pipes). The heated precipitate makes direct contact with the pipes (heating by conduction) and increases the unit efficiency. The thermal transfer efficiency allows fluidized bed coal plants to burn at cooler temperatures and less NO_x is emitted than in a conventional pulverized coal plant.

CFB boilers can burn fuels other than coal and the lower temperatures of combustion (800 °C) have other benefits as well. CFB generation is an emerging technology and new or upgraded units have come on-line around the world in recent years.

Carbon sequestration is another technology being considered by various electric utilities. Carbon sequestration technology is theorized to remove up to 90% of the CO_2 created by coal combustion. After combustion, the CO_2 is captured, compressed, and transported to sequestration sites where the CO_2 may be used for enhanced oil recovery or for other industrial processes. One idea is to compress the CO_2 gas and store the CO_2 in the basalt formations in eastern Oregon and eastern Washington. The CO_2 gas is expected to react with the minerals in the basalt to form solid calcium carbonate. Carbon sequestration in the Columbia River basalts has not been proven at the present time.

The various types of advanced coal resources studied in the 2006 IRP are assumed to be located in neighboring states in close proximity to fuel supply, with significant transmission investment required to get the energy to Idaho Power's load center. The cost estimates and operating parameters for advanced coal generation in the plan are based on data from an independent engineering firm. Potential generation studied in each of the various portfolios ranged from 250 MW up to 600 MW of additional advanced coal capacity over the 20-year planning period.

Advanced Coal Technology Advantages

- Abundant, low-cost fuel
- Potentially lower greenhouse gas emissions if CO_2 is sequestered
- Potential for financial incentives
- Dispatchable resource

Advanced Coal Technology Disadvantages

- New, unproven technologies
- Higher capital costs than pulverized coal
- Long construction lead times

Combined-Cycle Combustion Turbines

Until recently, combined-cycle combustion turbine (CCCT) plants have been the preferred choice for new commercial power generation in the region. CCCT technology carries a low initial capital cost compared to other baseload resources, has high thermal efficiencies, is highly reliable and offers significant operating flexibility, and emits less harmful emissions when compared to coal. The construction of CCCT plants in the region has slowed substantially in recent years due to increasing natural gas prices. In addition, renewable alternatives and energy efficiency measures have become more competitive. If natural gas prices were to decline, another period of significant CCCT development could occur and many feasible existing sites in the region are close to natural gas mainlines. While there is no current shortage of natural gas, it is widely believed supplies will become constrained and efforts will have to be made to tap off-shore sources via liquefied natural gas (LNG) import capability.

The traditional CCCT plant consists of gas turbine generators equipped with heat recovery steam generators to capture heat from the turbine exhaust. Steam produced from the heat recovery generators powers a steam turbine generator to produce additional electricity. In a CCCT plant, heat that would otherwise be 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 parameters for biomass-fueled generation in the plan are based on data from the NWPCC'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 turbine or combustion turbine. Photovoltaics is the technology involving the solid-state conversion of sunlight to electricity via reflective solar cells. Solar-powered generation may be viable in parts of southern Idaho based on atmospheric and shading conditions, and could potentially help serve peaking needs in the region on hot sunny days. However, solar generation is an intermittent resource.

Solar thermal technologies are more suited to large-scale power generation than photovoltaics. While both solar thermal and photovoltaic technologies are commercially established, both technologies are expensive. Solar energy is primarily used to serve small loads isolated from the main power grid, where extension of distribution lines is not feasible for economic or geographic reasons. The cost estimates and operating parameters for solar thermal and solar photovoltaic generation in the 2006 IRP are based on data from the Annual Energy Outlook published by the DOE in March 2006. Due to the high estimated costs, no solar generation resources were included in the portfolios analyzed for the 2006 Integrated Resource Plan.

Nuclear

The Energy Policy Act of 2005 authorizes funds to be appropriated for the development of a "next generation" nuclear power project at the INL. The project would consist of the research and development, design, construction, and operation of a prototype plant, including a nuclear reactor used to generate electricity, produce hydrogen, or both. The target completion date for the prototype nuclear reactor is September 2021. For fiscal years 2006–2015, $1.25 billion has been authorized for appropriation. In addition, the Act authorizes additional appropriations deemed necessary between fiscal years 2016–2021 to complete the project. Whether funds will actually be appropriated to develop the project is unknown at the present time.

The Act also establishes tax credits for up to 6,000 MW of new advanced nuclear power development. Projects must be in service by January 2021 to qualify. Multiple projects in the southeastern states will likely make up the next 6,000 MW of development, and therefore qualify for the credits. The first of these projects are expected to be on-line by 2014. Idaho Power will follow the progress of these projects in the coming years. Special attention will be paid to the issues surrounding spent nuclear fuel disposal.

In light of the INL project being identified in the recent legislation, a PPA for a 250 MW share of the proposed project beginning as early as 2022 was included in the portfolios studied in the 2006 IRP. Idaho Power recognizes that there are no specifically defined attributes or refined cost estimates available to date for the project. For financial modeling purposes, cost estimates and operating parameters for the project were based on nuclear generation data from the Annual Energy Outlook published by the DOE in March 2006. Idaho Power will monitor the progress of this R&D nuclear effort and provide an update in the 2008 Integrated Resource Plan.

As can be seen in Figures 5-1, 5-2, and 5-3, nuclear generation may provide relatively low-cost baseload generation with no greenhouse gas emissions.

Nuclear Advantages

- Forecasted low fuel costs
- Forecasted adequate fuel availability

- Lack of greenhouse gas emissions
- Potential low cost of production
- Proven technology (existing reactor types)

Nuclear Disadvantages

- Potential lack of public acceptance, due primarily to safety concerns
- Nuclear waste disposal issues and concerns
- Construction cost uncertainties
- Potential public risk due to accidents or security issues

Hydroelectric

Hydropower is the foundation of Idaho Power's generation fleet. The existing generation is low-cost and does not emit potentially harmful pollutants like fossil fuel-based resources. For various reasons, Idaho Power does not believe it is practical to develop new large hydropower projects. However, there is the potential for economical development of small hydropower, especially projects less than 10 MW in size. As shown in Figures 5-1, 5-2, and 5-3, the cost of hydropower generation fares well when compared to other generation technologies. The cost estimates for small-scale hydro resources were developed from data taken from the NWPCC's Fifth Plan (2005). No hydropower projects were included in the portfolios analyzed in the 2006 IRP; however, small projects may be developed and added through PURPA contracts.

Efficiency Upgrades at Existing Facilities

Opportunities to increase hydropower generation in the future exist through efficiency upgrades at Idaho Power's existing projects. Many of Idaho Power's hydro facilities are 50–70 years old. While the generating units have been maintained in excellent condition, new design technology—primarily hydraulic design software—has opened the door for potential turbine efficiency improvements. The primary opportunity for increasing hydropower capacity is through the replacement of turbine runners. Idaho Power is investigating numerous projects at its Mid-Snake facilities, and has already begun the installation of new turbine runners at the Upper Salmon "B" facility. Idaho Power will continue to pursue economically favorable upgrades at its hydro plants as they are identified. Upon receipt of a new FERC license for the Hells Canyon Complex, potential turbine runner replacement projects at those plants will be evaluated based on new license operating constraints.

Idaho Power will continue to look for cost effective efficiency upgrades at its existing thermal generating stations. Efficiency upgrades at existing thermal facilities are typically extremely cost effective. Table 2-2 identifies several of Idaho Power's recent upgrades to existing facilities.

Transmission Path Upgrades

In its review of the 2004 IRP, the IPUC recommended Idaho Power expand its analysis of possible transmission projects, associated costs, and potential risks in the 2006 IRP. In order to comply with the FERC's Standard of Conduct requirements, Idaho Power contracted with an outside consultant to provide the technical expertise required to evaluate and screen a range of transmission options. After the initial screening, a request was submitted on the OASIS website for Idaho Power's transmission planners to analyze the necessary upgrades for the finalist portfolios. Figures 5-4, 5-5, and 5-6 show 30-year nominal levelized cost of production estimates based on baseload capacity factors, peaking capacity factors, and cost of capital and fixed operating costs.

**Figure 5-4. Transmission Plus Market Purchase Alternatives
30-Year Nominal Levelized Cost of Production
at Baseload Capacity Factors**

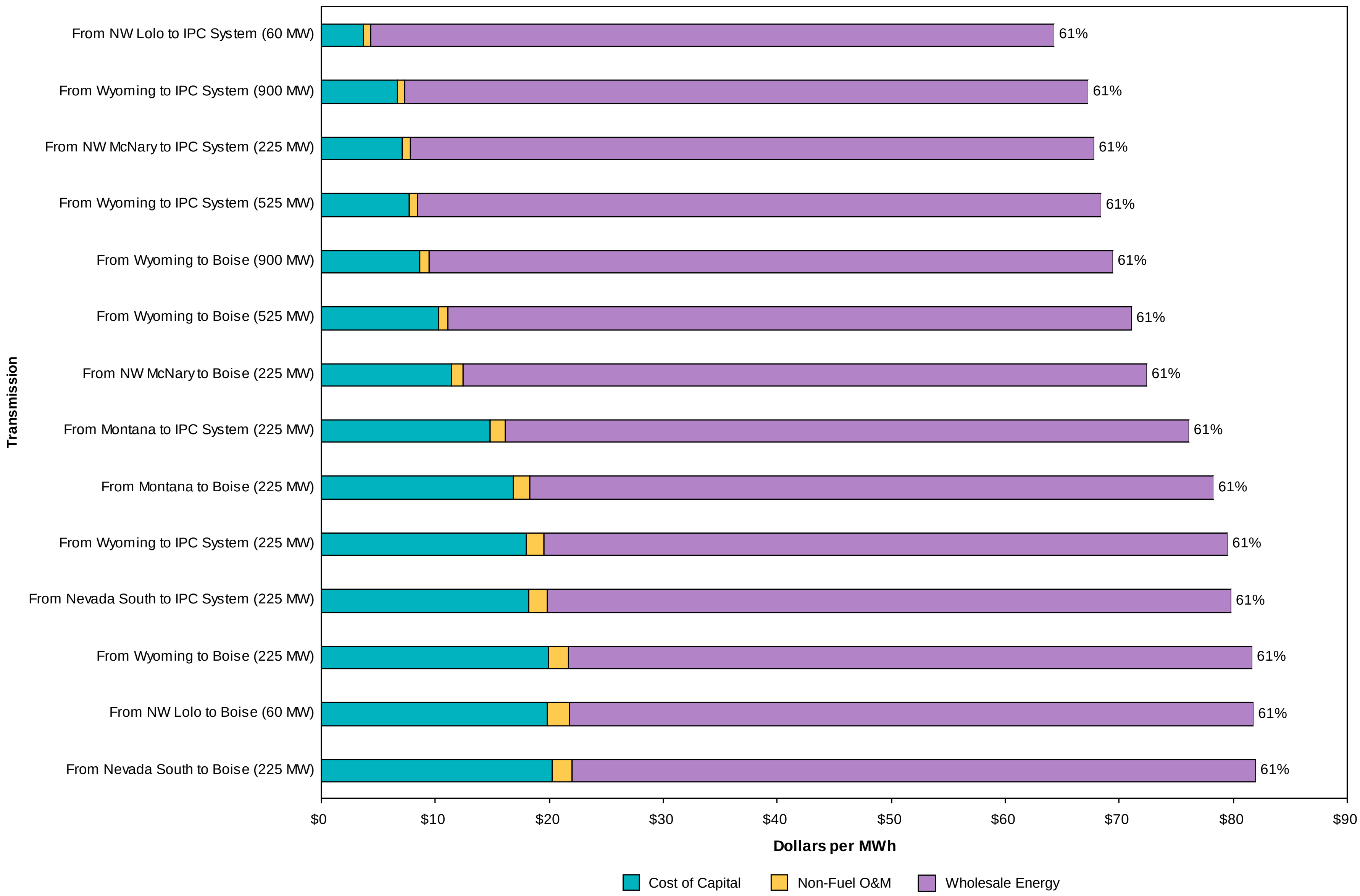


Figure 5-5. Transmission Plus Market Purchase Alternatives
30-Year Nominal Levelized Cost of Production
at Peaking Service Capacity Factors

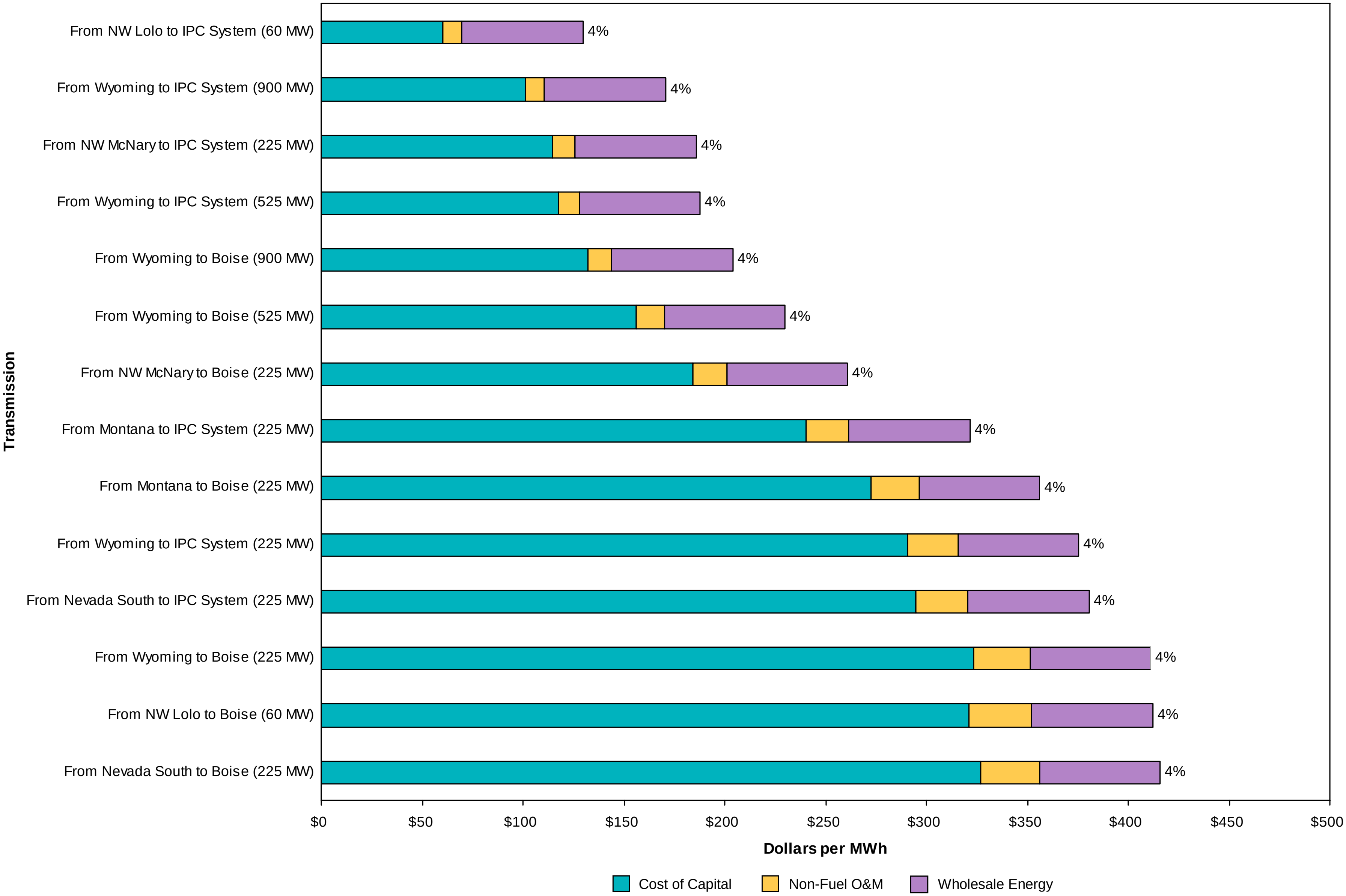
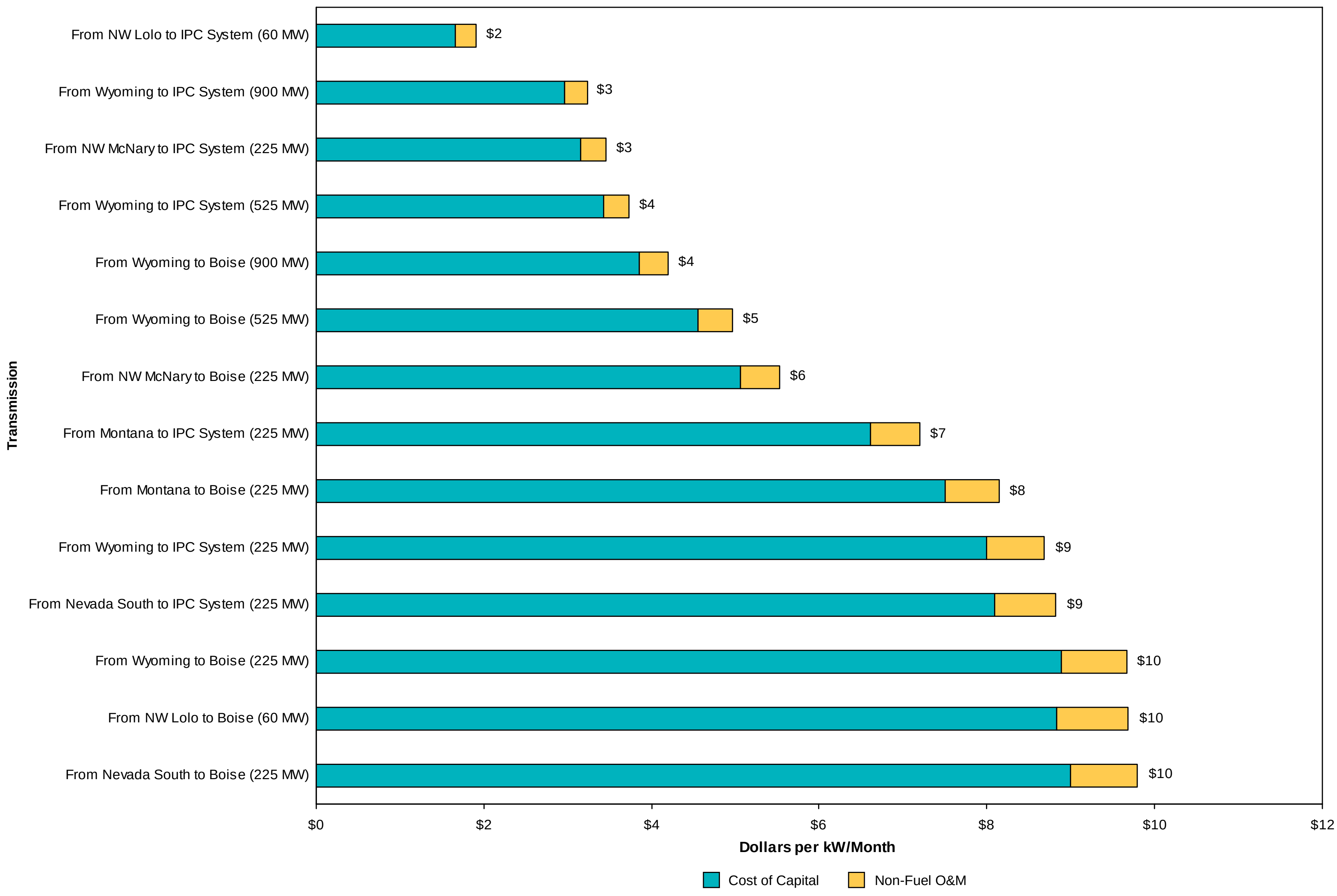


Figure 5-6. Transmission Plus Market Purchase Alternatives
30-Year Nominal Levelized Fixed Costs
Cost of Capital and Fixed Operating Costs



The following general alternatives were selected with the consultant's assistance as the most viable transmission alternatives. Fourteen variations of these general alternatives were analyzed and are shown in Figures 5-4, 5-5, and 5-6.

- McNary (Columbia River) to the Locust Substation (Boise) via Brownlee
- Lolo (Lewiston area) to Oxbow
- Bridger, Wyoming to the Boise Bench Substation via the Midpoint Substation
- Garrison or Townsend, Montana to the Boise Bench Substation via the Midpoint Substation
- White Pine, Nevada to the Boise Bench Substation via the Midpoint Substation.

McNary to Locust via Brownlee

The McNary to Brownlee portion of the project consists of a new, single conductor, 230 kV transmission line from the substation at McNary Dam to Idaho Power's Brownlee Dam Substation, with new 230 kV terminals at both ends. The distance between the McNary and Brownlee substations is approximately 215 miles. The estimated simultaneous capacity of the McNary to Brownlee link is 225 MW.

In-depth studies to determine simultaneous ratings for the selected transmission projects were not conducted as part of the IRP, and consequently estimates of simultaneous capacity discussed in the 2006 IRP should be considered preliminary in nature. Detailed studies to more accurately predict the resultant capacity of a project when integrated into the existing regional transmission system will be needed as a part of the design process for any project chosen for construction. The detailed studies are judged to be beyond the scope of the 2006 Integrated Resource Plan.

The portion of the transmission line from Brownlee to Boise consists of approximately 70 miles of new, single conductor, 230 kV transmission line from Brownlee to Idaho Power's Ontario Substation, and 30 miles of new, single conductor, 230 kV transmission line from Ontario to Idaho Power's Locust Substation via a new 230 kV switchyard at Garnet. The simultaneous capacity for the Brownlee to Boise portion is estimated at 300 MW.

Lolo to Oxbow

The Lolo to Oxbow transmission project consists of reconductoring 63 miles of an existing 230 kV single-circuit line to a higher grade conductor. The estimated simultaneous capacity resulting from the upgrade ranges from 60–75 MW.

Bridger, Wyoming to Boise Bench via Midpoint

The Bridger, Wyoming to Boise Bench project consists of a segment from the substation at the Jim Bridger thermal plant to Idaho Power's Midpoint Substation near Twin Falls and a second segment from Midpoint to the Boise Bench Substation. Two alternatives for the Bridger to Midpoint transmission line have been explored: 1) a new, two-conductor, bundled, 345 kV, single-circuit line, and 2) a new, three-conductor, bundled, 500 kV, single-circuit line. Both of the alternatives are estimated to require approximately 300 miles of transmission line replacement and are projected to include a new transformer and associated equipment at the Midpoint Substation.

The present transmission system connecting the Midpoint and Boise Bench substations consists of three, 230 kV lines. A variety of options for upgrading transmission capacity between the two stations has been considered. The options, with the corresponding estimated increases in simultaneous capacity, include the following:

1. Rebuild the existing number one line by converting it from a single conductor to a two-conductor, bundled, 230 kV, single-circuit line. The number one line will then match the capacity of the other two Midpoint to Boise Bench lines, which would yield a 225 MW increase in simultaneous capacity.

2. Reconductor the existing number one line to a higher-grade conductor, which would yield a 150 MW increase in simultaneous capacity.

3. Build a new, two-conductor, bundled, 345 kV, single-circuit line, which would yield a 525 MW increase in simultaneous capacity.

4. Build a new, three-conductor, bundled, 500 kV, single-circuit line, which would yield a 900 MW increase in simultaneous capacity.

The 345 kV and 500 kV options are projected to require a new substation tie outside of the Boise Bench Substation because of constrained corridors into the existing station. The length of the transmission line upgrade for each of the four options is approximately 110 miles.

Garrison or Townsend, Montana to Boise Bench via Midpoint

The Montana to Boise transmission project consists of a portion from substations in Garrison or Townsend, Montana to the Midpoint Substation and a second portion extending from Midpoint to the Boise Bench Substation. The segment from Garrison or Townsend to Midpoint consists of approximately 280 miles of new, single conductor, 230 kV, transmission line. The estimated simultaneous capacity provided by this new line ranges from 225–300 MW.

The four options considered for increasing capacity between Midpoint and Boise are discussed previously in the Bridger to Boise via Midpoint sections.

White Pine, Nevada to Boise Bench via Midpoint

The Nevada to Boise project consists of a White Pine, Nevada to Midpoint link, and a second segment providing increased capacity between the Midpoint and Boise Bench Substations. The White Pine to Midpoint portion consists of approximately 315 miles of new, two-conductor, bundled, 345 kV, transmission line. The simultaneous capacity estimated for the Nevada to Midpoint segment is 525 MW.

The four options considered for increasing capacity between Midpoint and Boise are discussed in the Bridger to Boise via Midpoint section.

In the development of portfolios, the transmission projects were considered similar to other supply-side resources, with the projected supply of power related solely to the transmission capacity rather than the generating capacity. With respect to the transmission development costs, the projects are expressed in the resource stacking in terms of the costs to connect the existing system to the regional market location (e.g., McNary to Brownlee), and in terms of the costs to allow for increased capacity all the way to the Boise load center (e.g., McNary to Locust via Brownlee).

Considering the costs in terms of merely connecting the existing system to the regional market, without the associated upgraded connection to Boise, is considered to allow the transmission projects to be compared fairly with other supply-side resources burdened by only the transmission infrastructure costs required to connect the generating facility with the existing system.

Transmission Advantages

- No direct exposure to possible emission adders
- Low operating cost
- Expanded capacity for off-system sales opportunities
- Stability associated with possible long-term firm contracts (sales and purchase)

Transmission Disadvantages

- Exposure to potential market volatility
- Need for costly studies addressing possible environmental impacts of long-distance transmission corridors
- Considerable lead times required

Demand-Side Management

Idaho Power has worked with the EEAG and outside consultants to identify potential demand-side programs that may be cost effective. Potential programs were identified in four major customer classes—residential, commercial, irrigation, and industrial.

Each year, in accordance with IPUC and OPUC directives, Idaho Power submits an annual report detailing DSM program performance. The report for 2005 is included in *Appendix B–Demand-Side Management 2005 Annual Report*.

As discussed earlier, Idaho Power implements programs consistent with stated program objectives in electrical system resources and customer needs. The programs, as defined by the stated objectives fall within the following categories:

- Demand Response
- Energy Efficiency
- Market Transformation

A brief description of each of the functional categories is provided below.

Demand Response Programs

Idaho Power's demand response programs are designed to use control hardware to provide a means by which the operation of a consumer's end-use equipment may be modified to alter the maximum demand. The goal of demand response programs at Idaho Power is to reduce the summer peak demand periods and thus minimize the need for providing higher cost supply-side alternatives such as gas turbine generation or open market electricity purchases.

In developing effective programs for reducing peak summer demand, Idaho Power targets irrigation customers using high horsepower pumps and residential customers using central air conditioning. Both programs utilize programmable means to cycle customer equipment on and off during peak time periods in the summer. Both irrigation and residential air conditioning are characterized by dedicated summer use. Together, irrigation and residential usage represent approximately 60% of system summer peak demand.

Energy Efficiency Programs

DSM energy efficiency initiatives are applicable to all Idaho Power customer segments including residential, irrigation, commercial, and industrial customer classes.

A common theme of energy efficiency programs is the focus on identifying significant segments within the customer base where prevalent energy practices can be modified to deliver desired energy savings. Idaho Power has selected programs that target improvements in residential and commercial building construction.

Improvements in new building construction include promoting improvements in the design and construction phases for new buildings to include energy efficiency measures in framing, building envelope, insulation, lighting, cooling, venting, and electrical systems. In targeting new construction, a wider range of cost effective measures are available relative to those for existing construction. Methods promoted for existing buildings are focused on applications which are effective in retrofitting applications such as lighting, air infiltration reduction, heating and cooling system improvements, and maintenance practices.

Systems improvements are typically targeted at industrial, irrigation, and large commercial customers and are realized through the evaluation of a customer's systems and application of new designs, technologies and processes. Improvements include pumping, lighting, heating, cooling, and process improvements.

Technology improvements are applicable in all programs. Technology improvement examples include, computerized electrical system controls, cooling and compressor innovations, Compact Florescent Lighting (CFL), roofing, and fenestration materials.

Market Transformation Programs

Market Transformation programs target energy savings through engaging and influencing large national and regional organizations who are gatekeepers to decisions that impact energy usage in products, processes and procedures affecting electrical power consumption.

Idaho Power participates in the Alliance in conjunction with a consortium of neighboring utilities in the Pacific Northwest. The consortium provides sufficient scale to influence decisions in the supply/manufacturing chain toward energy efficiency. The collaborative approach returns energy savings that would otherwise be unreachable individually by virtue of pooling resources into a single organization that is solely focused on large-scale programs. Alliance activities include industry design standards, materials sourcing, advertising, process methodology, and others. Many of the DSM programs implemented in Idaho Power's service area are the result of Alliance activity, including ENERGY STAR®.

DSM Evaluation

Idaho Power has developed the framework and design of its demand-side portfolio with support from the IRPAC, EEAG and outside consultants. Idaho Power has worked together with the advisory councils and consultants to develop the demand-side portfolio strategy, implementation plans, and program details.

Key aspects of the demand-side portfolio development include:

- Strategic importance to energy system overall, including corporate and customer needs
- Program effectiveness in terms of energy savings and cost
- Focus on summertime peak load reduction programs
- Focus on lost opportunity areas of new construction
- Ensuring establishment of personnel, processes, and systems to support effective implementation, validation, measurement, and modification

The following programs were selected for full development and implementation as a part of the 2004 IRP:

- **Demand Response Programs**
  - Irrigation Peak Rewards
  - A/C Cool Credit
- **Energy Efficiency Programs**
  - ENERGY STAR® Homes Northwest (new construction)
  - Commercial Building Efficiency (new construction)
  - Industrial Efficiency (redesign)
  - Irrigation Efficiency

2006 IRP Demand-Side Programs

Two umbrella programs designed to bring a wide variety of energy efficiency improvements to existing buildings and structures in the residential and commercial segments were considered in the 2004 IRP. Because of their scope, the 2004 IRP action plan deferred program implementation to ensure adequate resources were in place for effective implementation.

The nature and scope of the two programs were identified in a study completed by Quantuum Consulting (now Itron Consulting) in November 2004, where an inventory of existing building energy profiles was developed along with expected energy savings associated with the application of improvement measures. The Quantuum study was filed with the IPUC in December 2004, as a supplement to the 2004 Integrated Resource Plan.

These two programs are considered for implementation as a part of the 2006 IRP. The programs are evaluated assuming a 50 percent incentive level (the level used in the 2004 plan), as well as a 75 percent incentive level.

In addition to the residential and commercial energy efficiency programs, an expansion of the existing Industrial Efficiency program is also considered as a part of the 2006 IRP. Initial implementation experience has identified a higher potential for energy savings in this segment and the proposed expansion in the 2006 IRP is designed to build program capacity to realize the potential.

Table 5-3 shows the effect of the programs on energy and peak loads. The energy effects of the residential and commercial existing-construction programs are based on the work completed by Quantuum Consulting in November 2004. The industrial efficiency contribution was estimated by Idaho Power. The table indicates the relatively large effect the three DSM energy efficiency programs will have on the resource portfolio. Implementing the three energy efficiency programs proposed in the 2006 IRP is anticipated to generate over 780,000 MWh of energy savings per year by 2025—a savings of 88 aMW annually.

Table 5-3. Potential Demand-Side Programs

2006 IRP Energy Efficiency Programs (2025)
Commercial Efficiency, Existing Construction (27 MW on peak, 18 aMW energy)
Industrial Efficiency (47 MW on peak, 40 aMW energy)
Residential Efficiency, Existing Construction (113 MW on peak, 29 aMW energy)

The existing commercial building and industrial programs are expected to deliver year-round baseload savings. The residential program targeting existing construction is expected to include residential air conditioning seasonal savings in addition to other annual energy savings through retrofit measures.

Idaho Power used both a static and dynamic analysis to analyze the DSM options. The static analysis evaluates the benefits of the programs on a standalone basis, without considering the impact on the energy portfolio on a hour-to-hour basis. The dynamic analysis utilizes the Aurora Electric Market Model to determine how each DSM program affects Idaho Power's power supply costs. The dynamic analysis considers Idaho Power's resource portfolio as well as regional electric markets. The Aurora analysis is designed to estimate the effects of the DSM programs on Idaho Power's simulated hourly power supply costs.

The static analysis compared estimated program costs and the hourly energy savings with a set of alternative hourly energy costs. The alternative hourly costs represent both heavy and light load market purchase forecasts from the Aurora preferred portfolio (P304 May 2006) as well as fixed plant costs associated with baseload energy and natural gas-fired peaking generation. The set of alternative hourly costs was used to compare the value of summer peaking resources to more constant load profiles. The results of the static analysis indicated that all three energy efficiency programs had benefit to cost ratios significantly greater than 1.0 and a lower levelized annual energy cost than all other resources with the exception of flashed steam geothermal with the PTC. Therefore, all three energy efficiency programs were included in all of the resource portfolios considered in the 2006 Integrated Resource Plan.

Each resource portfolio, including the three energy efficiency programs, was further analyzed to determine the present value of its portfolio power supply costs. Additional details related to the DSM program analysis are included in *Appendix D–Technical Appendix*.

The demand-side programs and supply-side resources are compared in a combined resource stack as shown in Figures 5-1 and 5-2. Figures 5-1 and 5-2 show that several demand-side programs compare favorably with traditional thermal generation. The attributes of the programs and resources and their contribution to the resource portfolio are more fully discussed in Chapter 6 as well as *Appendix D–Technical Appendix*.

2006 IRP DSM Program Description and Metrics

The following section presents a description and the program metrics of the three proposed DSM programs included in the 2006 IRP preferred portfolio.

Residential Efficiency Program–Existing Construction

Program Overview

The Residential Efficiency Program for existing construction is designed to reduce peak demand and increase energy efficiency in existing residential housing. This program was first introduced for consideration in Idaho Power's 2004 Integrated Resource Plan. However, IRPAC deliberations, in conjunction with an assessment of resource availability for implementation, concluded it was appropriate to first launch the residential programs targeting new construction (ENERGY STAR® Homes Northwest–launched in 2005) and to defer programs targeting existing construction. This approach is consistent with the adopted DSM strategy of first implementing programs that target lost opportunities in new construction. The IRPAC also requested, in bringing the program design forward in 2006, the analysis consider increasing the incentive level from 50% to 75% to capture more of the cost effective energy savings available from program implementation. The 75% incentive level was chosen for introduction to the 2006 resource stack.

Program Description

The program focuses on the application of energy efficiency measures including cooling system efficiency, CFL lighting, and air infiltration reduction to existing residential housing. The program design and development will leverage elements of DSM programs previously implemented in the residential segment.

Table 5-4 shows the program energy metrics, general program characteristics, and economic metrics for the Residential Efficiency Program–Existing Construction.

Table 5-4. Summary of Residential Efficiency Program–Existing Construction

Program Energy Metrics		
Average Demand	28.8 aMW	
Peak Reduction	113.0 MW	
Annual Energy	251,989 MWh	
General Program Characteristics		
Seasonality	Summer focus	
Dispatching Capabilities	No	
Target Market	Residential	
Target Size	390,000+ customers	
First Year Available	2007	
Program Duration	30 years	
Measure Life	12 years	
Economic Metrics (Discounted Present Values)	**Utility Cost**	**Total Resource**
Benefits	$248,338	$248,338
Costs	$66,917	$101,028
Net Benefits	$181,420	$147,309
Benefit Cost Ratio	3.7	2.5
Levelized Costs		
30-year ($/kWh)	$0.029	$0.044
Peak 30-year ($/kW/Month)	$5.34	$8.07

Commercial Efficiency Program–Existing Construction

Program Overview

The Commercial Efficiency Program is designed to reduce peak demand and increase energy efficiency in existing buildings for commercial customers. This program was first introduced for consideration in Idaho Power's 2004 IRP. However, as was the case with the residential program, implementation was deferred to provide focused resources for launching of new-construction programs (both commercial and residential launched in 2005). 2004 IRPAC deliberations in conjunction with guidance from EEAG concluded that it was appropriate to first establish programs for new construction (Commercial Building Efficiency Program–launched in 2005) and to defer existing construction programs. The strategy of first targeting lost energy efficiency opportunities in new construction was applied to residential construction as well.

Under IRPAC and EEAG guidance for bringing the program forward for consideration in the 2006 IRP resource stack, alternate participant incentive options were considered at the 50% and 75% levels. The 75% level was chosen for implementation in Idaho Power's 2006 Integrated Resource Plan.

Program Description

The program focuses on the application of energy efficiency measures including cooling, refrigeration, ventilation, and lighting to existing buildings in the commercial customer segment. The program design envisions providing evaluation services and support for the installation of improved technologies, processes, and controls for energy savings gains.

Initial program design elements under consideration include segmenting the target customers depending upon the nature and scope of the potential improvement and customer. Program design will include customer interface and integration with the Industrial Efficiency Program. Marketing efforts will target equipment vendors, service providers, and industrial engineers.

Table 5-5 shows the program energy metrics, general program characteristics, and economic metrics for the Commercial Efficiency Program–Existing Construction.

Industrial Efficiency Program Expansion

Program Overview

The Industrial Efficiency Program was first selected for implementation in the 2004 IRP. It is designed to increase energy efficiency for large industrial and commercial customers of Idaho Power in both Oregon and Idaho.

Program development and design elements were significantly dependent upon input from industrial customers as well as the EEAG and other stakeholders. The initial program has been extremely well received and customer demand for program services has exceeded available resources.

Table 5-5. Summary of Commercial Efficiency Program–Existing Construction

Program Energy Metrics		
Average Demand	18.4 aMW	
Peak Reduction	27.1 MW	
Annual Energy	161,157 MWh	
General Program Characteristics		
Seasonality	Summer focus	
Dispatching Capabilities	No	
Target Market	Commercial	
Target Size	50,000+ customers	
First Year Available	2007	
Program Duration	20 years	
Measure Life	10 years	
Economic Metrics (Discounted Present Values)	**Utility Cost**	**Total Resource**
Benefits	$165,241	$165,241
Costs	$32,030	$54,597
Net Benefits	$133,211	$110,644
Benefit Cost Ratio	5.2	3.0
Levelized Costs		
30-year ($/kWh)	$0.020	$0.035
Peak 30-year ($/kW/Month)	$10.15	$17.30

Program Description

The operational parameters of the Industrial Efficiency Program expansion remain effectively unchanged. The expansion identified in Idaho Power's 2006 IRP will focus on adding additional Idaho Power resources to better serve customer demand.

With the addition of the Commercial Efficiency Program–Existing Construction to the DSM portfolio, the Industrial Efficiency Program's marketing and administration processes will be refined to ensure effective customer interfaces for large commercial customers targeted by the Industrial Efficiency Program.

Table 5-6 shows the program energy metrics, general program characteristics, and economic metrics for the Industrial Efficiency Program Expansion.

Table 5-6. Summary of Industrial Efficiency Program Expansion

Program Energy Metrics		
Average Demand	40.4 aMW	
Peak Reduction	47.1 MW	
Annual Energy	353,939 MWh	
General Program Characteristics		
Seasonality	None	
Dispatching Capabilities	No	
Target Market	Industrial and commercial customers with BLC > 500 kW	
Target Size	300 customers	
First Year Available	2007	
Program Duration	20 years	
Measure Life	12 years	
Economic Metrics (Discounted Present Values)	**Utility Cost**	**Total Resource**
Benefits	$255,887	$255,887
Costs	$49,981	$91,885
Net Benefits	$205,906	$164,002
Benefit Cost Ratio	5.1	2.8
Levelized Costs		
30-year ($/kWh)	$0.022	$0.040
Peak 30-year ($/kW/Month)	$10.26	$18.86

General DSM Discussion

DSM energy and peak demand estimates are typically measured at the point of delivery (customer's meter). Supply-side resource generation estimates are usually made at the point of generation. Line losses occur between the point of generation and the point of delivery at the customer's meter. The line losses reduce the delivered generation from supply-side resources.

In order to make the energy efficiency programs comparable to supply-side resources, the projected energy savings of the DSM programs are increased by the amount of energy that would have been lost in transmission and delivery if the load had been provided by a supply-side resource.

Demand-side and energy conservation measures are often seen as synonymous. Unfortunately, generic energy conservation programs are unlikely to be sufficient to meet the peak-hour deficiencies Idaho Power faces during the near-term of this resource plan. Specific demand-side measures targeting peak-hour demand reduction are more likely to address the projected peak-hour deficiencies.

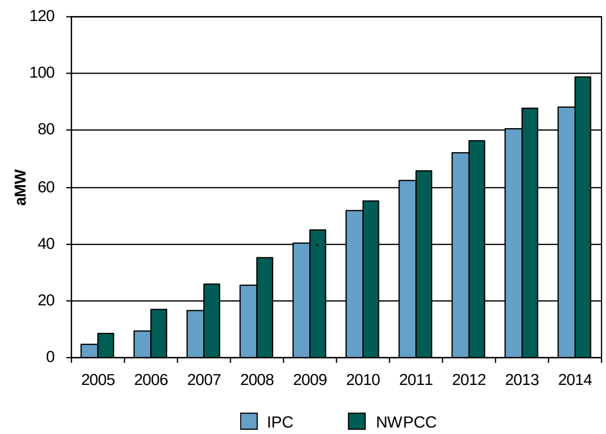
Idaho Power continues to implement the A/C Cool Credit program to the levels identified in the 2004 IRP. Over 4,700 residential customers have voluntarily enrolled in the program since its inception. During times of need, such as during the summer peak, Idaho Power briefly interrupts program participant's air conditioners. Interruption periods are commonly 15 minutes or less each half-hour between 2–8 p.m. Idaho Power has divided the program participants into two groups and by alternately interrupting each group, the group air conditioning demand can be reduced by half.

Idaho Power expects to add between 9,000–10,000 residential customers each year and most of these new customers will have air conditioning. The A/C Cool Credit program is designed to mitigate this growth in residential air conditioning demand. Due to the nature and timing of the projected peak-hour deficits, energy efficiency and demand response programs must be carefully designed to cost-effectively address the projected deficits.

Regional DSM Savings Comparison

Figure 5-7 shows Idaho Power's DSM portfolio energy savings in average megawatts (including the proposed 2006 IRP programs). In the figure, the Idaho Power forecast is compared to a savings potential derived from NWPCC and Alliance estimates. This derived potential is based on the NWPCC estimate of total Northwest conservation potential. Idaho Power has determined its allocated share by applying the Alliance's metric for allocating Idaho Power's percentage of regional load (6.5%).

Figure 5-7. Existing and Potential DSM



The figure provides a useful benchmark for gauging the progress of DSM efforts; however, there are significant differences between the two statistics that merit noting:

- The NWPCC potential number is for all conservation measures, not just those associated with Idaho Power's DSM programs.
- The Idaho Power numbers exclude savings associated with building codes and federal energy standards.
- The Idaho Power forecast excludes market transformation (Alliance) savings beginning in 2010 as this marks the expiration date of the existing contract with the Alliance.
- The NWPCC potential is based on region-wide macro economic forecasts; Idaho Power's savings are based on corporate planning commitments.

- The Alliance allocation, based on changing economic conditions, may be subject to change.

Idaho Power's forecast is based on program startup and implementation schedules as presented in *Appendix B–Demand-Side Management 2005 Annual Report*. The program timelines are an integral part of Idaho Power's planning process and reflect the multi-faceted elements of planning supply-side and demand-side resources within the customer dynamics of Idaho Power's service area.

Resource Portfolios

Twelve different portfolios were analyzed in preparing the 2006 IRP. The resource portfolios were developed to explore a variety of different resource alternatives and to analyze the costs and benefits associated with each resource strategy.

The resource portfolios varied from a portfolio with no coal-fired resources and almost 1,000 MW of new renewable resources, to a portfolio with 1,475 MW of new transmission import capacity. Other portfolios included a predominantly coal-fired portfolio which included almost no natural gas-fired generation, and a number of diversified portfolios include varying amounts of wind, geothermal, coal, simple-cycle and combined-cycle combustion turbines, and demand-side resources. Table 5-7 shows the composition of each of the original 12 portfolios.

Each considered portfolio, when combined with Idaho Power's existing resources and expected allocation of in-bound transmission capacity for serving native load customers, will fully meet

Table 5-7. Comparison of Initial Portfolios

Resource Summary	P1[1]	P2[2]	P3[3]	P4[4]	P5[5]	P6[6]	P7[7]	P8[8]	P9[9]	P10[10]	P11[11]	P12[12]
Combined-Cycle Combustion Turbine	–	–	–	–	225	–	–	–	–	–	–	–
Combined Heat and Power	150	–	110	50	50	100	50	50	100	100	100	100
Coal	–	–	250	850	–	500	500	250	250	1,000	250	250
Combustion Turbine (CT)	–	170	–	170	170	510	340	680	510	–	–	–
Seasonal Peak Demand-Side Management (DSM)	187	187	187	187	187	187	187	187	187	187	187	187
Geothermal (Binary)	490	50	225	50	50	150	50	250	150	50	50	50
Integrated Gasification Combined Cycle (IGCC)	–	–	250	–	600	300	300	300	300	–	–	–
Nuclear	250	250	250	250	250	-	-	-	-	250	250	900
Wind	500	100	250	100	100	100	100	350	100	100	1,100	100
Wyoming IGCC with Carbon Sequestration	–	–	–	–	–	–	–	–	250	–	–	–
Transmission	450	1,260	285	–	–	–	225	–	–	225	225	225
Total Nameplate including Seasonal Peak DSM (MW)	2,027	2,017	1,807	1,657	1,632	1,847	1,752	2,067	1,847	1,912	2,162	1,812
Energy including Seasonal DSM Energy (aMW)	1,080	394	1,139	1,187	1,106	1,050	909	959	1,050	1,356	1,016	1,289
Transmission Capacity (MW)	450	1,260	285	–	–	–	225	–	–	225	650	225
Peak Capacity including Seasonal Peak DSM (MW)	1,102	662	1,284	1,562	1,537	1,752	1,432	1,732	1,752	1,592	892	1,492

1 Green Portfolio
2 Transmission Portfolio
3 2004 IRP Preferred Portfolio
4 Basic Thermal Portfolio
5 Advanced Coal Portfolio
6 2004 IRP Plus More Geothermal (Binary) and CTs
7 2004 IRP Plus More Geothermal (Binary), CTs, and Transmission
8 Less Coal, More Geothermal (Binary), and CTs
9 2004 IRP Plus IGCC with Sequestration
10 All Coal Portfolio
11 Bridger to Boise Transmission
12 Nuclear Portfolio

Idaho Power's projected monthly energy needs under the 70th percentile water and 70th percentile energy planning criteria. Each considered portfolio will eliminate the projected peak-hour transmission overloads from the Pacific Northwest under the 90th percentile water and 95th percentile peak-load conditions for all months in the planning period except July 2007. To eliminate the projected peak-hour transmission overload in July 2007, all portfolios require a firm purchase of approximately 60 MW. The 60 MW firm purchase will most likely be delivered to the east side of Idaho Power's system.

Each portfolio was analyzed using the Aurora Electric Market Model over a 20-year study period. The portfolio costs include both the cost of capital and operating costs of the various additional supply-side and demand-side resources proposed within each portfolio, as well as the cost of capital and operating costs of Idaho Power's existing and committed resources. In addition to these fixed and variable operating costs, the Aurora model determines wholesale market purchases and sales for each portfolio. The expected case portfolio costs are based on:

- 50th percentile (median) water conditions, 50th percentile load conditions
- Expected fuel price forecasts for Sumas natural gas and Wyoming specific and regional coal price forecasts
- CO_2 emission adder of $14.00 per ton (in 2006 dollars) beginning in 2012

The 20-year stream of portfolio costs from Aurora were discounted to 2006 dollars using the established discount rate (6.93% after tax), and the resulting values from the portfolios were compared. The Aurora financial modeling assumes Idaho Power will own and operate the resources included in each portfolio throughout the planning period. If the energy and capacity are obtained through PPAs or other arrangements, the capital costs of the portfolio would be lower and the variable operating (energy) cost of the portfolio would be higher. A full listing of the portfolios with additional detail regarding the portfolio costs, capacity, and resource timing is included in *Appendix D–Technical Appendix*.

Portfolio Selection

The 12 original portfolios were analyzed under four different scenarios:

1. **Expected:** CO_2 adder of $14/ton beginning in 2012, expected gas prices and the PTC continues to be renewed in its current form until 2012 when it is assumed to be eliminated
2. **GHG50:** CO_2 adder of $50/ton beginning in 2012, expected gas prices and the PTC continues to be renewed in its current form until 2012 when it is assumed to be eliminated
3. **GHGZero:** No CO_2 adder, expected gas prices and the PTC continues to be renewed in its current form until 2012 when it is assumed to be eliminated
4. **HighGas:** CO_2 adder of $14/ton beginning in 2012, high gas prices and the PTC continues to be renewed in its current form until 2012 when it is assumed to be eliminated

The Aurora Electric Market Model was used to estimate the portfolio costs for each of the 12 portfolios under each of the above four scenarios for the 20-year planning period. The present value of each portfolio for each scenario was calculated for the following:

a. **Market Purchases:** Present value of each portfolio's market purchases over the 20-year planning period

b. **Resource Total:** Present value of the resource costs for each portfolio including resource costs associated with existing resources (ownership, fuel, and other operating and maintenance costs). Resource costs include all of the fixed and variable production costs for the portfolio

c. **Market Sales:** Present value of each portfolio's market purchases over the 20-year planning period

d. **Total Cost:** The summation of items a, b, and c

The above calculations yield 192 sets of results (12 portfolios x 4 scenarios/portfolio x 4 sets of results/scenario = 192 sets of results). These results were then used to rank the portfolios according to the following three criteria:

1. **Sales to (Purchases + Resource costs) Ratio:** This ratio was calculated for each portfolio for each scenario listed above (1–4). This metric is a measure of the portfolio's reliance on (and exposure to) the market. See *Appendix D–Technical Appendix* for details of the portfolio rankings according to this criterion

2. **Average Total Cost (PV):** The present value of the total costs for each portfolio scenario listed above was determined and the resulting values were averaged for each portfolio. PV of Average Total Cost = (PV Expected Total Cost + PV GHG50 Total Cost + PV GHGZero Total Cost + PV HighGas Total Cost)/4. Table 5-8 contains details of the portfolio ranking according to this criterion

Table 5-8. Portfolio Comparison

Portfolio	Average PV Resource Costs*	Rank	Average PV Total Costs* (Resource Costs + Market Purchases − Market Sales)	Rank
P1[1]	$7,381,896	8	$5,044,664	3
P2[2]	$5,590,614	1	$5,666,507	12
P3[3]	$6,396,324	2	$5,180,902	8
P4[4]	$7,369,168	7	$5,049,059	4
P5[5]	$7,553,796	10	$5,443,658	11
P6[6]	$7,328,346	6	$5,172,530	7
P7[7]	$6,766,460	3	$5,244,052	9
P8[8]	$7,190,408	4	$5,025,018	2
P9[9]	$7,290,214	5	$5,134,741	5
P10[10]	$7,675,873	12	$5,172,510	6
P11[11]	$7,397,872	9	$5,291,036	10
P12[12]	$7,595,844	11	$4,872,631	1

*Note: Costs averaged for the following four scenarios:
(1) CO_2 adder = $14/ton of CO_2 emissions (Expected Case)
(2) CO_2 adder = $50/ton of CO_2 emissions (GHG50)
(3) CO_2 adder = $0/ton of CO_2 emissions (GHGZero)
(4) High natural gas price scenario

[1] Green Portfolio
[2] Transmission Portfolio
[3] 2004 IRP Preferred Portfolio
[4] Basic Thermal Portfolio
[5] Advanced Coal Portfolio
[6] 2004 IRP Plus More Geothermal (Binary), and CTs
[7] 2004 IRP Plus More Geothermal (Binary), CTs, and Transmission
[8] Less Coal, More Geothermal (Binary), and CTs
[9] 2004 IRP Plus IGCC with Sequestration
[10] All Coal Portfolio
[11] Bridger to Boise Transmission
[12] Nuclear Portfolio

3. **Average of Resource Costs:** The present value of the resource costs for each portfolio scenario was determined and the resulting values were averaged for each portfolio. PV Average of Resource Cost = (PV Expected Resource Cost + PV GHG50 Resource+ PV GHGZero Resource + PV HighGas Resource)/4. See Table 5-8 for details of the portfolio ranking according to this criterion

Rankings were assigned to each portfolio based on its sales ratio and the Average of Total Cost and Average of Resource Total metrics—the lowest cost portfolio was ranked first, and the highest cost portfolio was ranked 12. Results of the portfolio rankings are discussed in Chapter 6.

6. Risk Analysis

Selection of Finalist Portfolios

Idaho Power Company identified four of the original 12 portfolios for additional risk analysis. The four portfolios, designated as P1, P3, P4, and P11, demonstrated unique strengths and positive characteristics in the initial scenario cost analysis. The characteristics used to distinguish these portfolios as candidates for further risk analysis were identified in the following three screening analyses:

1. **Average Total Expected Cost:** In the 2006 IRP, average total expected cost includes the fixed costs of resource ownership, variable operating and maintenance costs, the costs of any market purchases, and the revenue received from surplus sales. However, if a portfolio relies on considerable surplus sales or purchases, there is exposure to changes in market prices (e.g., selling at lower and purchasing at higher than forecast prices). In consideration of the exposure to market risks, the original 12 portfolios were also ranked by the average of resource costs.

2. **Average Resource Cost:** In addition to ranking portfolios on the present value of their expected portfolio power supply costs (average expected cost scenario), the original 12 portfolios were also ranked by the sum of resource costs. The resource cost analysis only considers the fixed and variable costs associated with the resources—the costs of market purchases and revenue from market sales are not included. Idaho Power has forecast high generation, transmission, and distribution system capital requirements associated with meeting future demand. The resource cost identifies the portfolio with the lowest capital and operating cost.

3. **Sales to Supply Cost Ratio:** The sales to supply cost analysis considers the ratio of market sales revenue to sum of market purchases and resource costs. The denominator of the ratio, market purchases plus resource costs, can be considered the cost to meet the forecast load. Although all portfolios were designed to meet the monthly average load and peak-hour load planning criteria, the portfolios include differing amounts of resources, and subsequently, the portfolios contain differing amounts of surplus sales. The sales to supply cost ratio identifies the portfolios with the largest proportion of surplus sales. Surplus sales can potentially lower the cost of a resource portfolio. However, there is a possibility that actual surplus

Highlights

- Four finalist portfolios were selected from the initial portfolios for additional qualitative and quantitative risk analyses.
- Quantitative risk factors analyzed include the implementation of a CO_2 tax, the price of natural gas, the variability of hydrologic conditions, cost of construction, and capital and market risk.
- Qualitative risk factors analyzed include regulatory risk, declining Snake River base flows, FERC relicensing risk, resource commitment and siting risks, and fuel, implementation, and technology risks.

sales prices will be lower than forecast which could potentially turn an expected low-cost portfolio into a high-cost portfolio. When the original 12 portfolios were ranked by the sales to supply cost ratio under the Expected, GHG50, GHGzero and the HighGas scenarios, P4 finished in first place in all four scenarios.

The 12 portfolios were assessed on a combination of quantitative and qualitative elements (see *Appendix D–Technical Appendix* for the complete quantitative ranking). The quantitative elements include Average Total Expected Cost, Average Resource Cost, and Sales to Supply Cost Ratio. The qualitative screening yielded seven identified portfolios which are summarized below:

- **Lowest Average Total Cost:** P1, P4, P8, and P12
- **Lowest Average Resource Cost:** P2 and P3
- **Lowest Sales to Supply Cost Ratio:** P2, P3, and P11

Table 6-1 summarizes the primary strengths and weaknesses of the seven identified portfolios.

Based on the quantitative and qualitative elements mentioned and input from the IRPAC, the final four portfolios selected for further refinement and analysis were P1, P3, P4, and P11.

Before proceeding with additional risk analysis, a number of changes were made to the selected portfolios to incorporate the strengths observed in portfolios not selected, address construction lead-time concerns, and to reduce the implementation risk associated with

Table 6-1. Summary of Primary Strengths and Weaknesses Used for Portfolio Selection

Portfolio	Strengths	Weaknesses
P1—Green	Low exposure to carbon legislation	Heavy reliance on geothermal Geothermal technology is outside Idaho Power's area of expertise
P2—Transmission	Low exposure to market sales Low average resource cost	High exposure to market purchases High average total cost
P3—2004 IRP Preferred	Low exposure to market sales Low average resource cost Diversified fuel mix	High average total cost
P4—Basic Thermal	Low average total cost	High exposure to carbon legislation High exposure to market sales Heavy reliance on coal
P8—Less Coal, More Geothermal (Binary), and CTs	Low average total cost	Heavy reliance on natural gas
P11—Bridger to Boise Transmission	Low exposure to market sales Low exposure to carbon legislation Access to integrate high capacity wind resources	High average total cost
P12—Nuclear	Lowest average total cost Low exposure to carbon legislation	High exposure to market sales Heavy reliance on uranium Nuclear technology is outside Idaho Power's area of expertise Long-term waste storage issues

over-reliance on certain generation technologies or fuel types deemed too uncertain. To avoid confusion with the original portfolios, P1, P3, P4, and P11 were renamed F1, F2, F3, and F4 respectively, to denote the finalist status of the resulting portfolios. Changes made to the portfolios are summarized below:

- **Portfolio F1–Green (originally P1):** The amount of geothermal generation was reduced from 550 MW to 400 MW and distributed in 50 MW increments throughout the planning period. The amount of transmission resource was reduced from 510 MW to 285 MW, and 250 MW of pulverized coal was added in 2013.

- **Portfolio F2–2004 IRP Preferred (originally P3):** The amount of geothermal generation was reduced from 225 MW to 150 MW, and the amount of CHP was increased from 110 MW to 150 MW.

- **Portfolio F3–Basic Thermal (originally P4):** The amount of pulverized coal generation was reduced by 300 MW, and 300 MW of IGCC generation was added.

- **Portfolio F4–Bridger to Boise Transmission (originally P11):** The amount of wind generation was reduced from 1,100 MW to 600 MW, and the amount of geothermal generation was increased from 50 MW to 150 MW. The amount of CHP generation was reduced from 100 MW to 50 MW. Resource timing was shifted to accommodate estimated construction lead time associated with the 500 kV transmission line.

Idaho Power transmission planning was consulted using the OASIS Open Access Forum to estimate the backbone transmission upgrade costs necessary to integrate each of the finalist portfolios into Idaho Power's system. The additional backbone transmission costs were included in the capital cost of each portfolio for the final analysis. A summary of each of the four finalist portfolios is shown in Table 6-2.

Risk Analysis of Finalist Portfolios

The objective of the risk analysis is to identify portfolios that perform well in a variety of possible scenarios. Each finalist portfolio was analyzed for quantitative risk associated with carbon tax, natural gas prices, capital and construction costs, hydrologic variability, and market risk. In addition, consideration was given to qualitative risks such as regulatory environment, declining Snake River base flows, FERC relicensing, resource timing and commitment, resource siting, fuel, implementation, and technology.

Quantitative Risk

Idaho Power conducted a boundary analysis to assess quantitative risk. For example, the impacts on the resource portfolios under the following CO_2 emission adder scenarios: 1) no CO_2 adder, 2) a $14 per ton adder, and 3) a $50 per ton adder. Likewise, Idaho Power has analyzed each portfolio's performance with a low, expected, and high forecast for natural gas prices. In addition to the emission adder and natural gas forecast scenarios, each of the four finalist portfolios was analyzed to determine the sensitivity of the portfolio total cost to discount rate assumptions and construction cost variances. The impact associated with the observed historical variability in hydrologic conditions was also quantified and incorporated into the analysis. And, finally, market risk was analyzed to assess exposure related to market sales and purchases.

The risk analysis presented below analyzes quantitative risk with a subjective probability assessment of the boundary conditions. In all of the boundary condition cases, Idaho Power has

Table 6-2. Summary of Finalist Portfolios

Resource Summary	MW
Portfolio F1	
DSM	187
Wind	500
Geothermal (Binary)	450
Coal	250
CHP	150
Transmission	285
Nuclear	250
Total Nameplate	**2,072**
Energy	1,211
Transmission	285
Peak	1,262
Portfolio F2	
DSM	187
Wind	250
Geothermal (Binary)	150
CHP	150
Transmission	285
Coal	500
Nuclear	250
Total Nameplate	**1,772**
Energy	1,089
Transmission	285
Peak	1,250
Portfolio F3	
DSM	187
Wind	100
CHP	50
Geothermal (Binary)	50
IGCC	300
Coal	550
CT	170
Nuclear	250
Total Nameplate	**1,657**
Energy	1,161
Transmission	–
Peak	1,562
Portfolio F4	
DSM	187
Wind	600
CHP	50
Transmission	1,475
Geothermal (Binary)	150
Nuclear	250
Coal	250
Total Nameplate	**2,962**
Energy	902
Transmission	750
Peak	923

assigned a probability estimate to the high, expected, and low scenarios. The greatest likelihood is assigned to the expected case. For example, under the discount rate assessment of the capital risk, the expected case was assigned a probability of 60 percent, the high case was assigned a probability of 30 percent, and the low case was assigned a probability of 10 percent. Each scenario's impact is then weighted by the assigned probability to arrive at an analytical assessment of the overall impact of each particular risk. The analytical assessment of the overall impact of each qualitative risk is then summarized to quantify each portfolio's sensitivity to the risks.

Carbon Risk

It is believed that CO_2 emissions will be regulated within the 20-year timeframe addressed in the 2006 IRP. Over the last few years, there has been a significant increase in the number of legislative proposals related to climate change. There has been a steady increase in activity ranging from 7 proposals introduced in the 105th Congress (1997–1998), to 96 proposals introduced in the 108th Congress (2003–2004).[1] The Climate Stewardship Act (S.139), introduced by Senators McCain and Lieberman, received 43 votes in the Senate in 2003. At the state level, 28 states either have or are planning to institute a greenhouse gas emission reduction strategy.[2] Washington State recently passed a law regulating CO_2 from new electric generation plants which requires that 20 percent of the CO_2 from new plants either be taxed or be mitigated through offset projects[3] and Oregon passed a similar law in 1997.[4] A white paper titled "Design Elements of a

[1] Same as in the IRP

[2] "Climate Change Activities in the United States: 2004 Update," Pew Center for Climate Change, March 2004 (www.pewclimate.org).

[3] Washington House Bill 3141, http://access.wa.gov/leg/2004/Apr/n200431_0700.aspx.

[4] Oregon House bill 3283, 1997, http://www.energy.state.or.us/siting/co2std.htm.

Mandatory Market-Based Greenhouse Gas Regulatory System" was released by Senate Energy and Natural Resources Committee Chairman, Senator Pete V. Domenici (R-New Mexico) and Senator Jeff Bingaman (D-New Mexico).[5] The Domenici-Bingaman paper is another example of the momentum that is building for carbon controls or some system of regulations for greenhouse gases.

The magnitude of the CO_2 regulation risk faced by Idaho Power and its customers depends on the carbon intensity of the portfolio. Portfolios with a heavy emphasis on carbon-emitting resources face the risk of increased power supply costs as a result of future carbon regulations. Accordingly, Idaho Power believes it is prudent to incorporate reasonable estimates for the cost of CO_2 emissions into the IRP resource modeling and analysis, and to actively seek to lessen the exposure to financial risk associated with carbon emissions.

The expected case scenario used in the IRP assumes a cost of $14 per ton in 2006 dollars for carbon emissions beginning in 2012. The boundary conditions used in the analysis were $0 and $50 per ton of CO_2 for the low-case and high-case scenarios. The imputed costs of carbon emissions used in the risk analysis are derived from Order 93-695 from the OPUC (the OPUC order specified costs in 1990 dollars and the costs have been escalated and rounded to whole 2006 dollars for the 2006 IRP). While the OPUC order was the starting point for the CO_2 analysis, Idaho Power also confirmed that the costs represent reasonable estimates of the risk Idaho Power and its customers face due to potential future regulation of CO_2 emissions.

The CO_2 costs used in the 2006 IRP are consistent with two other recent analyses in the region. First, in its recent Integrated Resource Plan, PacifiCorp assessed the range of likely future scenarios and the associated costs, and found that $8 per ton (in 2006 dollars) of CO_2 was a reasonable value to represent the likely cost of carbon emissions. Second, a recent California PUC (CPUC) report also assessed the range of likely future scenarios of carbon regulation and the associated costs and concluded that a reasonable estimate for carbon costs is around $5 per ton of CO_2 in the near term, $12.50 per ton of CO_2 by 2008, and $17.50 per ton of CO_2 by 2013.[6] Further, the California report found carbon adder estimates ranged from a low of about zero up to $69 per ton of CO_2. In CPUC Decision 05-04-024 (April 7, 2005), the CPUC adopted the report's forecast of CO_2 adder values for use in avoided cost calculations. Both the expected case and boundary scenarios included in Idaho Power's 2006 IRP are consistent with PacifiCorp and the CPUC analysis. Table 6-3 contains the results of the carbon risk analysis for each of the portfolios. A summary of future views on the cost of reducing CO_2 emissions is included in *Appendix D–Technical Appendix*.

As illustrated in Table 6-9, the weighted CO_2 risk is the second largest risk identified in the quantitative analysis. Portfolio F3 is the most carbon-intensive portfolio and has the largest CO_2 risk. Portfolio F1 is the least-carbon intensive portfolio and, predictably, has the smallest carbon risk. The evaluation of CO_2 emission costs is the most significant risk addressed in the 2006 IRP. The value of the CO_2 adder used in the analysis will change the portfolio power supply costs by up to about $3.5 billion. Depending on the CO_2 adder assumptions, Portfolio F3 can range from nearly the lowest cost portfolio when the CO_2 adder is $0 per ton to the most expensive portfolio when the CO_2 adder is $50 per ton.

[5] Pew Center http://www.pewclimate.org/policy_center/analyses/sec/index.cfm

[6] Energy and Environmental Economics and Rocky Mountain Institute, *A Forecast of Cost Effectiveness Avoided Costs and Externality Adders*, prepared for the California Public Utilities Commission, January 8, 2004.

Table 6-3. Carbon Risk Analysis

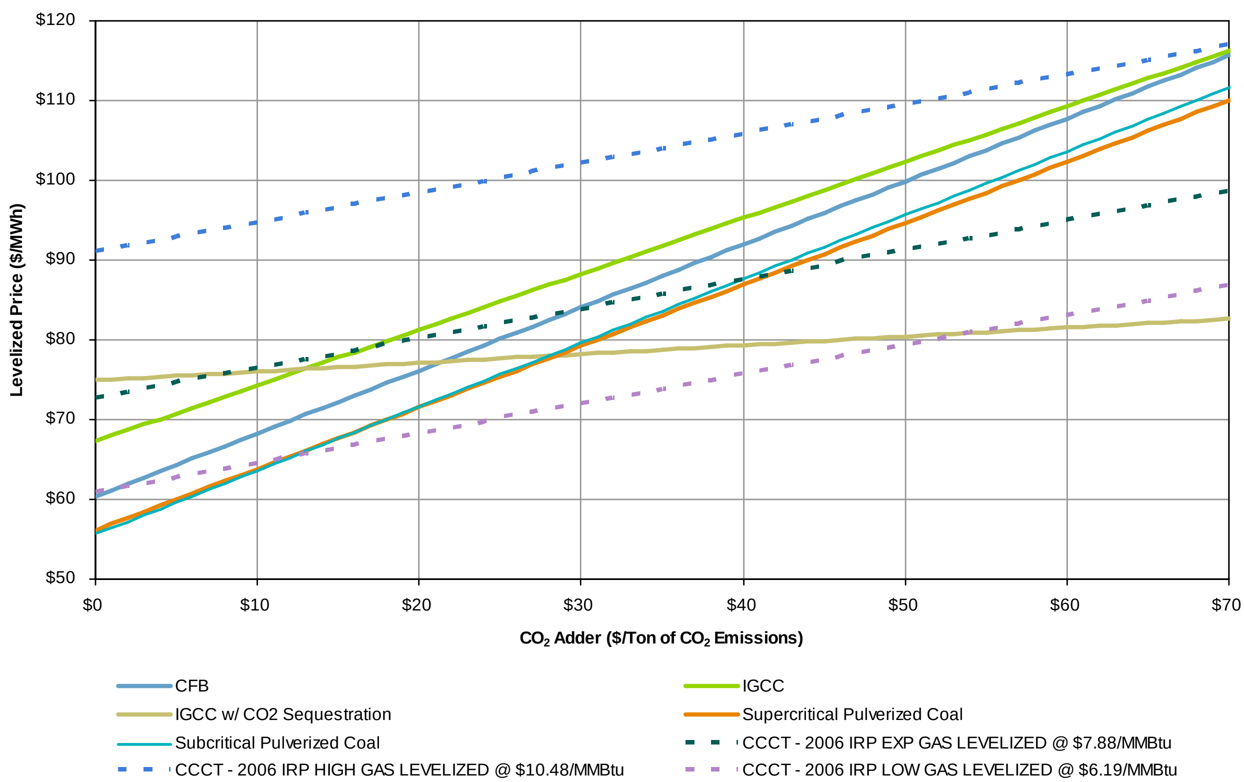
	Probability	PV of Portfolio Power Supply Cost ($000s)[1] F1	F2	F3	F4
Low Case (CO_2 @ $0/ton, PTC)	30%	$4,026,335	$4,102,146	$3,877,915	$4,145,480
Expected Case (CO_2 @ $14/ton, PTC)	50%	$4,829,327	$5,051,302	$4,938,464	$5,054,667
High Case (CO_2 @ $50/ton, PTC)	20%	$6,635,637	$7,307,411	$7,477,039	$7,235,209
Relative Risk					
Low Relative to Expected		($802,992)	($949,156)	($1,060,548)	($909,187)
High Relative to Expected		$1,806,310	$2,256,109	$2,538,575	$2,180,542
CO_2 Adder Risk		$120,364	$166,475	$189,551	$163,352
Relative Risk		–	$46,111	$69,186	$42,988

[1] Based on the 20-year planning period.

Figure 6-1 illustrates the levelized price sensitivity of several fossil-fuel technologies to a range of CO_2 emission adder values. Key crossovers occur at emission adder values of approximately $13 and $28/ton. For CO_2 adders greater than $13/ton, IGCC with sequestration is preferred to IGCC without sequestration. However, for expected case natural gas prices, pulverized coal technologies yield the lowest levelized cost for any value of a CO_2 adder up to $28/ton. If the CO_2 adder is increased to above $28/ton, then IGCC technology with sequestration results in the lowest levelized cost.

Another interesting aspect of Figure 6-1 is the levelized cost crossover points which occur between technologies for different natural gas price assumptions. If low natural gas prices are assumed (levelized $6.10/MMBTU), then for a CO_2 adder above $12/ton, natural gas-fired CCCTs are preferred to pulverized coal. If the CO_2 adder is below $12/ton, pulverized coal is

Figure 6-1. Levelized Price for Generating Resources vs. Carbon Adder



the preferred choice. However, if the CO_2 adder increases to $54/ton, then IGCC with sequestration is preferable to natural gas-fired CCCTs.

If expected case gas prices are assumed (levelized $7.88/MMBTU), the crossover point between pulverized coal and a CCCT increases to $41/ton. However, for expected case natural gas prices, the preferred choice is never a CCCT plant. The preferred choice is pulverized coal for CO_2 adders up to $28/ton and IGCC with sequestration for CO_2 adders above $28/ton. As illustrated in Figure 6-1, natural gas prices and CO_2 adder assumptions are extremely important in determining the preferred coal technology.

Natural Gas Price Risk

Idaho Power faces two types of natural gas price risk. Direct risk is the price uncertainty that Idaho Power faces to acquire natural gas to fuel its own resources. Indirect risk is the electricity market uncertainty that Idaho Power faces when it buys or sells power in a regional market where natural gas-fired resources set wholesale power prices. Portfolios that rely heavily on the market for purchases or sales will face a greater indirect natural gas price risk. The forecast effect of natural gas price risks on the total portfolio costs under expected, low, and high gas price scenarios are shown in Table 6-4. The expected, low, and high natural gas price forecasts are included in *Appendix D–Technical Appendix*.

Table 6-4 shows the portfolio power supply costs under three different gas price scenarios. The portfolio power supply costs include both the expenses and revenues associated with all of the portfolio fuel supply costs, surplus sales, and costs associated with Idaho Power’s existing resources. In general, since neither Idaho Power’s existing portfolio of resources nor any of the four preferred portfolios utilize natural gas-fired resources in baseload service, with the exception of CHP, most of the risk identified in this analysis would be classified as indirect price risk. It is interesting to note that all portfolios benefit from an increase in natural gas prices. Portfolio F1 benefits the most, F3 benefits second most, and F2 and F4 benefit to a lesser extent. Portfolios F1, F2, and F3 all benefit more under the high-gas price scenario than they lose under the low-gas price scenario. The lone exception is F4, which actually loses more under a low-gas price scenario than the portfolio gains under a high-gas price scenario.

Natural gas-fired generation resources are, at least in part, naturally hedged in certain markets. When natural gas-fired resources are the marginal generation resource setting regional power prices, an increase in fuel expense resulting from an increase in gas prices will most likely be matched by an increase in wholesale electricity prices. Since the fuel expense for renewable resources is independent of natural gas prices, an increase in natural gas prices may increase the revenue stream from

Table 6-4. Natural Gas Price Risk Analysis

		PV of Portfolio Power Supply Cost ($000s)[1]			
	Probability	F1	F2	F3	F4
Low Case (Low NG Price)	20%	$5,370,093	$5,433,057	$5,426,070	$5,430,309
Expected Case (Expected NG Price)	50%	$4,829,327	$5,051,302	$4,938,464	$5,054,667
High Case (High NG Price)	30%	$4,174,748	$4,584,172	$4,322,029	$4,679,995
Relative Risk					
Low Relative to Expected		$540,766	$381,755	$487,606	$375,642
High Relative to Expected		($654,579)	($467,130)	($616,435)	($374,672)
Natural Gas Price Risk		($88,220)	($63,788)	($87,409)	($37,273)
Relative Risk		–	$24,432	$811	$50,947

1 Based on the 20-year planning period.

resources that do not rely on natural gas fuels. Like the renewable energy resources, portfolios that rely on coal face indirect natural gas price risk because the natural gas prices affect the price at which the surplus power is sold in the regional market.

Capital and Construction Cost Risk

Capital costs and construction cost of each portfolio represents the capital risk. With the exception of coal-based IGCC projects, which present a unique technology risk, the resource portfolios include mature technologies. Although geothermal-based generation resources are unproven on a commercial scale in Idaho, the technology is considered to be mature. While capital construction costs are generally known for the various resources, there are always risks associated with any major construction project, including the risk of cost overruns. One way to mitigate construction cost risk is to enter into a long-term PPA for the output of a project—transferring the risk of cost overruns to the project developer. However, even with a PPA, the development and construction risks are not completely eliminated. If a developer defaults on a PPA contract, Idaho Power will have to purchase replacement energy and rely on litigation to resolve the matter. Historically, Idaho Power's preference has been to own hydro, coal-fired, and natural gas-fired generation resources and enter into PPAs for output from other types of generation resources.

The impacts associated with a 10 percent cost overrun are shown in Table 6-5.

The portfolio discount rate sensitivity quantifies the effects on the present value of the portfolio power supply costs as a result of changes in Idaho Power's discount rate. If Idaho Power's cost of capital increases or decreases as a result of changes in borrowing costs, the calculation of the present value of each portfolio's costs will change when evaluated at either higher or lower discount rates. In addition to the effects on borrowing costs, changes in the discount rate may also affect the value of a portfolio. For example, if the sum of the benefits produced by two portfolios over a given time period are equal, but the benefits occur earlier in one portfolio, the relative difference in value between the portfolios will decrease as the discount rate is lowered. Likewise, the relative difference in value between the portfolios will increase as the discount rate is increased. Given current interest rate levels, Idaho Power believes there is a greater probability that interest rates will go up in the future. This belief is reflected in the probabilities assigned in this analysis and is shown along with the portfolio sensitivity to discount rate assumptions in Table 6-6.

Hydrologic Variability Risk

A large proportion of Idaho Power's generation comes from hydroelectric projects located on the Snake River in southern Idaho. The yearly

Table 6-5. Cost of Construction Risk Analysis

		($000s)			
		F1	F2	F3	F4
Construction Cost		$6,040,547	$5,273,473	$4,765,601	$6,159,336
Construction Cost (PV)		$3,382,172	$2,691,944	2,301,965	2,949,095
Construction Cost Relative to Lowest Cost Portfolio		$690,228	–	($389,979)	$257,150
Adjustments for Possible PPAs					
Total Construction Cost Potentially Transferred to PPAs	Real	$4,404,463	$2,502,606	$1,432,392	$3,091,099
	PV	$2,339,479	$1,159,772	$708,882	$1,289,233
Net Idaho Power Construction	Real	$1,636,084	$2,770,867	$3,333,210	$3,068,237
	PV	$1,042,694	$1,532,172	$1,593,084	$1,659,861
Adjusted Construction at Risk	PV	$1,042,694	$1,532,172	$1,593,084	$1,659,861
Cost of Construction Risk	10%				
Weighted Risk	PV	$104,269	$153,217	$159,308	$165,986

Table 6-6. Capital Risk Analysis (Discount Rate)

	Probability	PV of Portfolio Power Supply Cost ($000s)[1] F1	F2	F3	F4
Low Case (4.93%)	10%	$5,957,429	$6,226,562	$6,101,501	$6,280,252
Expected Case (6.93%)	60%	$4,829,327	$5,051,302	$4,938,464	$5,054,667
High Case (8.93%)	30%	$4,191,850	$4,279,459	$4,176,338	$4,288,426
Relative Risk					
Low Relative to Expected		$1,128,102	$1,175,260	$1,163,037	$1,225,585
High Relative to Expected		($637,477)	($771,843)	($762,126)	($766,241)
Capital Risk		($78,433)	($114,027)	($112,334)	($107,314)
Relative Risk		$35,594	–	$1,693	$6,713

[1] Based on the 20-year planning period.

variation in flows in the Snake and Columbia River systems directly affect Idaho Power's overall power supply costs. The cost sensitivity of the four finalist portfolios to the historic yearly variance in hydro conditions of the Snake and Columbia Rivers was evaluated for this analysis. Each of the four finalist portfolios was simulated in the Aurora electric market model over the 20-year planning period using a sampling of 20-year streamflow sequences selected from the 1928–2002 normalized hydrologic record for the Columbia and Snake River Basins. The 20-year streamflow sequences were selected at 5-year increments starting with 1928 (i.e., 1928–1947, 1933–1952). This selection process resulted in 16 separate streamflow sequences used for the analysis. For simulations using hydro sequences starting after 1984, the 20-year sequence was wrapped to append data from the beginning of the hydrologic record so that all streamflow samples contain a 20-year period of data.

Assumptions used in the hydrologic variability analysis include the expected 20-year forecast for fuel prices, 50th percentile average load, 90th percentile peak-hour load, CO_2 at $14 per ton beginning in 2012, and the renewable PTC phasing out in 2012. The present value of the total portfolio cost for each of the 16 sequences is shown in Figure 6-2. Portfolio F3 resulted in the lowest total cost of the four portfolios, and Portfolio F1 has the least variability with a standard deviation of $404,033. Summary statistics for all of the portfolios are shown in Table 6-7.

Table 6-7. Summary Statistics of Hydrologic Variability Analysis

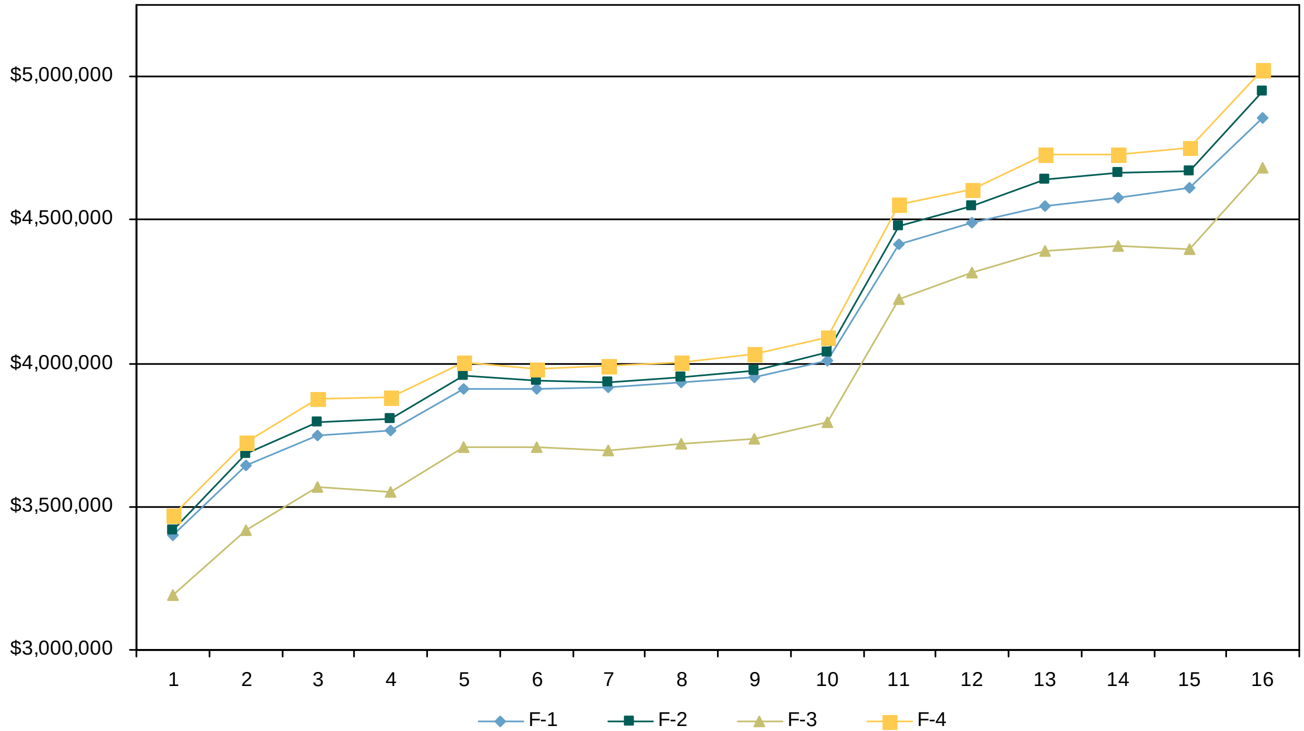
Portfolio	Standard Deviation of Population ($000s)	Average Total Cost ($000s)
F1	$404,033	$4,105,714
F2	$426,159	$4,152,612
F3	$417,646	$3,906,168
F4	$433,850	$4,215,530

Market Risk

Each of the finalist portfolios was evaluated with respect to its exposure to market sales and purchases. Each portfolio relies on the regional market for sales when Idaho Power has surplus energy or purchases during times when customer demand exceeds total generation. A summary of the market risk analysis is shown in Table 6-8.

Because the resource planning criteria eliminate the monthly energy deficiencies for all portfolios, under no portfolio is Idaho Power a net importer of power. Under all portfolios, Idaho Power is a net exporter of power and customers benefit from regional market sales. However, as a seller of power, Idaho Power is exposed to the risk that market prices will decline when making sales. Likewise, Idaho

Figure 6-2. Hydrologic Variability Portfolio Comparison ($000s)



Power is also exposed to the risk of an increase in market prices when it is purchasing power. All market participants, including Idaho Power, face price risks when buying or selling in the market. The magnitude of the risk depends on the characteristics of the portfolio of power supply resources. Portfolios with a large quantity of either market sales or market purchases have greater exposure to changes in market prices.

As indicated in Table 6-8, Portfolio F1 has the most surplus sales and, therefore, the most exposure to a decrease in market prices.

Portfolio F4 has the most market purchases and, likewise, the most exposure to an increase in market price. Market exposure is reduced in portfolios that minimize the amount of market purchases and surplus sales. Overall, the analysis indicates that Portfolio F1 has the most downside market risk while Portfolio F4 has the least downside market risk.

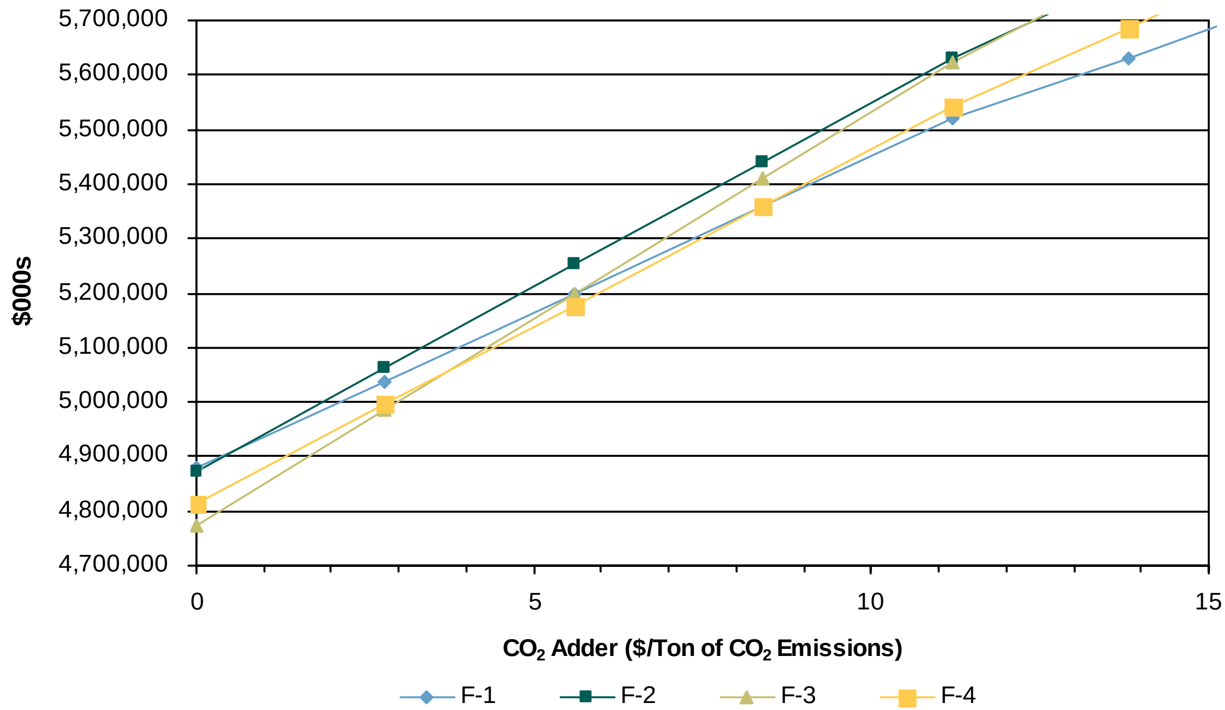
Figure 6-3 compares the present value of risk-adjusted portfolio costs for each of the finalist portfolios over the 20-year planning period. *Appendix D–Technical Appendix* contains additional information regarding the

Table 6-8. Market Risk Analysis

	PV of Portfolio Power Supply Cost ($000s)[1]			
	F1	F2	F3	F4
Total Portfolio Power Supply Cost (Expected NG Price)	$4,829,327	$5,051,302	$4,938,464	$5,054,667
Market Sales (Expected Case)	($3,129,008)	($2,342,043)	($2,674,437)	($2,097,896)
Market Purchases (Expected Case)	$202,083	$343,787	$249,795	$428,502
Sensitivity to a 10% Decrease in Market Sales	$312,901	$234,204	$267,444	$209,790
Sensitivity to a 10% Increase in Market Purchases	$20,208	$34,379	$24,980	$42,850
Market Risk	$333,109	$268,583	$292,423	$252,640
Relative Risk	$80,469	$15,943	$39,783	–

[1] Based on the 20-year planning period.

Figure 6-3. Present Value of Risk Adjusted Portfolio Costs



total risk-adjusted present value portfolio costs over the entire range of CO_2 adder analyzed in the 2006 Integrated Resource Plan.

Qualitative Risk

The qualitative risks associated with the four finalist portfolios are more difficult to assess. The goal is to select a portfolio that is likely to withstand unforeseen events. By building on the 2004 IRP strategy of utilizing a diverse mix of smaller, short lead-time resources, the 2006 preferred plan incorporates the flexibility to adjust resource timing in the shorter term by either accelerating or deferring actual in-service dates to more closely match actual load growth. The 20-year planning horizon of the 2006 IRP incorporates additional long lead-time resources, including an additional coal-fired plant, transmission projects, additional geothermal resources, and a nuclear project. While the 20-year planning horizon provides a better view of future resource needs, proceeding with participation agreements or incurring development costs for resources required later in the 20-year planning period does present a commitment risk.

Regulatory Risk

Idaho Power is a regulated utility with an obligation to serve its customer load and therefore, is subject to regulatory risk. Idaho Power expects that future resource additions will be approved for inclusion in the rate base and that it will be allowed to earn a fair rate of return on its investment. Idaho Power includes public involvement in the IRP process through an IRP Advisory Council and by opening the IRP Advisory Council meetings to the public. The open public process allows a public discussion of the IRP and establishes a foundation of customer understanding and support for resource additions when the plan is submitted for approval. The open public process reduces the regulatory risk associated with developing a resource plan.

Significant changes in public policy represent risks that must be considered in a resource plan involving long-lived assets. In addition to the CO_2 risk, other possible changes in public policy, such as the implementation of an RPS, could impact Idaho Power and have been considered in this plan. Although the RPS effects are not presented in quantitative terms, a balanced portfolio helps to position Idaho Power to meet an RPS in the event such regulations are enacted. Along with the possible enactment of an RPS, the question of whether or not Idaho Power should purchase green tags or Renewable Energy Credits (RECs) was considered. Green tags and RECs are discussed in more detail in the Public Policy section in Chapter 1.

Declining Snake River Base Flows

Idaho Power has senior water rights on the Snake River and is very concerned about the declining base flows in the Snake River. The declining base flows have the potential to dramatically lower the energy output from the Snake River hydropower system. The 2006 IRP resource requirement is based on 70th percentile water conditions as determined by the historical record. If Snake River streamflows continue to decline, Idaho Power will require additional resources to meet customer load. The declining Snake River flows have caught the attention of many parties including the State Legislature, the State Department of Water Resources, the water users, the river naturalists, and Idaho Power.

FERC Relicensing Risk

A reduction in operational flexibility as a result of the FERC relicensing process will have a negative impact on Idaho Power's ability to economically meet its customers' needs. Working within the constraints of the original FERC licenses, the Hells Canyon Complex has historically provided operational flexibility which has benefited Idaho Power's customers. As a result of the FERC relicensing process, operational requirements, such as minimum reservoir elevations, minimum flows, and limitations on ramping rates, may become more stringent. The loss of operational flexibility will limit Idaho Power's ability to control the flow of water through the Hells Canyon Complex and, ultimately, any loss of operational flexibility will increase power supply costs.

Three of the four finalist portfolios add at least 250 MW of additional wind resources, and one portfolio adds 600 MW of wind resources. One reason Idaho Power can economically add wind resources is because of the inherent flexibility in its hydropower system. Idaho Power intends to use the flexibility of the Snake River hydropower system—especially the operational flexibility of the Hells Canyon Complex—to integrate new wind resources. Reductions in the operational flexibility of the Snake River hydropower system will require that Idaho Power add additional generation resources to serve peak-hour loads, and furthermore, a reduction in operational flexibility may negatively affect the ability of Idaho Power to economically integrate wind resources.

Resource Commitment Risk

Idaho Power also faces risk in the timing of, and commitment to, new resources. There are a number of factors that influence the actual timing of resource planning. Examples include economic growth in the service area, electricity usage patterns, performance of existing resources, and the pace of PURPA resource development. During the preparation of the 2004 IRP, Idaho Power recognized that early commitment to a large resource might be inadvisable. However, while early commitment to a large resource is still a concern, there is also a growing concern that Idaho Power needs to initiate the development of baseload resources to avoid being caught in a situation where a combustion turbine becomes the only resource that can be successfully deployed in time to meet forecast peak-hour loads. The Advisory Council members still agree that it is prudent to pursue a variety of resource types to spread the risk of policy, siting, and system integration issues. The preferred plan addresses this uncertainty by adding a diverse mixture of resources in smaller increments, such as a reduction in size of the 500 MW coal-fired resource which was identified in the 2004 IRP and was expected to be on-line in 2011. The

2006 IRP has reduced the size of the coal-fired resource to 250 MW, and the on-line date has been delayed until 2012 or later depending on the portfolio.

Resource Siting Risk

The risks associated with resource siting and public acceptance is clearly an issue that must be considered. Resource siting becomes even more critical when attempting to locate a generation resource close to an existing load center. In addition to navigating the permitting requirements associated with developing generation resources, Idaho Power must also ensure that public opposition to the project is not of such a magnitude that successful development of the project is jeopardized. While Idaho Power does not anticipate developing future generation projects that are impractical from a public acceptance standpoint, it is clear that widespread public opposition to a project can result in permitting delays, increased development costs, delays in the project's commercial operation date and, in some instances, cancellation of a project. The problems Sempra encountered during the past two years with the Idaho Valley project near Twin Falls, Idaho, and the difficulties Idaho Power faced with the Garnet Project are indicative of the risks associated with resource siting and public acceptance.

Fuel, Implementation, and Technology Risks

The finalist portfolios contain a diverse range of generating resources each with differing implementation, fuel, and technology risks. The relative risk of the finalist portfolios is subject to debate, but assumed to be equal for the quantitative analysis shown above, meaning that the risk of high interest rates or the risk of a carbon tax is independent of the chosen portfolio. However, each portfolio may respond differently to the individual risk scenario.

The following section highlights specific resources within the portfolios and describes Idaho Power's interpretation of the risk profiles associated with each resource and acknowledges that the portfolios may contain unique and differing risks.

Fuel-Related Risks

- **Geothermal:** There exist differing opinions on the quantity and quality of developable geothermal sites within Idaho Power's control area. The absence of proven reserves of geothermal energy increases the risks associated with Portfolio F1, which relies heavily on geothermal resources.

- **Coal:** There are a number of concerns with coal-fired resources. If a coal-fired project is not developed at or near the coal mine, then fuel transportation becomes a significant concern. Fuel-related issues that must be considered include uncertainty of future transportation rates, the terms and conditions of future rail contracts, and the adequacy of service by the railroads. In addition, if the coal supply is not controlled or owned by Idaho Power, then there is uncertainty regarding future fuel costs. One way to address the coal price uncertainty is to negotiate long-term contracts with the coal companies. Another option is to acquire rights to the coal reserve and develop a mine-mouth project similar to the Jim Bridger plant.

- **Nuclear:** Fueling for nuclear plants is not anticipated to be a problem; however, no long-term solution for nuclear waste storage is currently available. The lack of a long-term waste storage facility increases the risks of environmental damage and adverse human health effects from a spent nuclear fuel containment breach. The uncertainty surrounding the costs of waste storage, as well as the potential costs of nuclear contamination, increase the risk associated with nuclear generation.

- **Natural gas:** Southern Idaho is served by the Northwest Pipeline Corporation and the pipeline is fully subscribed. Additional capacity needs will have to be met by either purchasing capacity from others or acquired by expanding the existing pipeline system.

Implementation and Operation Risk

- **Transmission:** The strategy of building additional transmission capacity without the certainty of having the right to call on a specific resource that is dedicated to providing Idaho Power's energy needs contains a higher degree of operational risk than building transmission with a dedicated resource. The Pacific Northwest transmission projects identified in Portfolios F1, F2, and F4 increase Idaho Power's access to the highly liquid markets surrounding the Mid-C trading hub. The transmission project between Wyoming and Idaho identified in Portfolio F4 is developed to support the implementation of Wyoming and Idaho wind and eastern Idaho geothermal resources, as well as accessing additional energy and capacity from the regional energy market to serve peak-hour needs. One of the assumptions embedded in Portfolio F4 is that energy will be available or contracted for purchase at the times Idaho Power needs the energy and capacity to service critical peak-hour loads.

- **Nuclear:** The INL Advanced Nuclear project is subject to federal politics and the U.S. Congress may materially alter the project or eliminate the project for unrelated political reasons. In addition, Idaho Power's ability to successfully negotiate an acceptable PPA for output of a completed project is speculative.

- **Geothermal:** Idaho Power has limited experience in contracting, identifying, and developing geothermal electrical generation facilities and no experience building or operating such facilities. The lack of direct geothermal experience increases the risk associated with the development of geothermal resources.

- **Coal:** Idaho Power's coal-fired resources are all jointly-owned with other utilities. While it is likely that Idaho Power's next coal-fired resource will be a jointly-owned facility, the exact ownership arrangement has not been decided. Jointly-owned facilities enable minority participants to realize the economies of scale enjoyed with a larger resource, while reducing the risk associated with having a large amount of generation on a single shaft, solely-owned large project. However, a jointly-owned facility will likely require siting of the facility to be a compromise rather than sited specifically to serve Idaho Power's load.

- **Siting:** Several generation types require the facility to be sited at the source of the motive force. This is especially true of renewable resources such as wind, geothermal, and hydro projects. Often, the projects are located in remote locations far from load centers. Remote locations increase the development and transmission costs associated with the renewable resources. Likewise, some fuel types such as coal, gas, or nuclear may encounter public and political pressure against a project being located near load centers or being constructed at all.

- **DSM Implementation:** The DSM implementation risk is the likelihood that the actual energy savings and peak reductions from the projected DSM programs will be significantly different than the projected energy savings and peak reduction targets. Should the actual energy savings and peak reductions be less than the estimated values, Idaho Power may require additional supply-side resources to meet customer load. If the DSM programs exceed the estimated savings, future supply-side resources may be delayed.

Technology Risk

Technology risk is an area that Idaho Power must consider in the 2006 IRP. The principal area in which technology risk is considered in this IRP is the uncertainty associated with developing new advanced coal technologies, such as IGCC as compared to developing a conventional or an advanced supercritical or ultra-supercritical cycle pulverized coal-fired resource with state-of-the-art emission-control technology. IGCC resources provide increased efficiency, reduced emissions, and the ability to capture and potentially sequester CO_2 emissions at reduced costs. However, the trade-offs for IGCC plants are higher capital costs and the uncertainty of the technology. The different aspects of the IGCC trade-offs are discussed in more detail in the Public Policy section in Chapter 1.

While there are certain risks associated with each type of generation resource, Idaho Power is specifically concerned about the technology risk associated with IGCC projects. IGCC projects have received a considerable amount of attention in the press recently. Idaho Power is supportive of IGCC technology and believes that IGCC technology may play a significant role in meeting the nation's future energy needs. However, Idaho Power also believes that there is a technology risk associated with developing an IGCC project for use with western coals. With only two operating IGCC projects in the entire United States, much of the electric industry—including Idaho Power—does not consider an IGCC project to be proven technology. Considering Idaho Power's modest size and the cost of an IGCC project, Idaho Power believes it would be imprudent to assume the IGCC development risk alone. However, Idaho Power does believe that taking a lesser share in a jointly-owned regional IGCC project is an appropriate way for Idaho Power to share the IGCC technology risk.

Risk Analysis Summary

The five types of risk previously addressed in the quantitative analysis (CO_2 adder, natural gas prices, capital and construction costs, and market risk) are summarized in Table 6-9. In all cases, natural gas price risk is shown as a negative number, indicating a reduction in portfolio power supply costs. Hydrologic variability risk is not included in the risk-adjusted total portfolio costs shown in Table 6-9 due to the magnitude of the results.

Portfolio F1 began the quantitative risk analysis with the lowest portfolio power supply costs at $4.8 billion, which is about $100 million lower that Portfolio F3, and about $225 million lower than resource Portfolios F2 and F4. After incorporating the weighted risks considered in the quantitative risk analysis, Portfolio F1 still has the lowest risk adjusted total portfolio cost—$5.8 billion. Portfolio F4 finished in second place with a risk-adjusted total portfolio cost of $5.9 billion, F2 finished in third place with a cost of $6.0 billion, and F4 finished in fourth place with a risk-adjusted total portfolio cost of $6.1 billion. It is interesting to note less than five percent separates the lowest and highest cost portfolios, indicating each of the finalist portfolios may present a reasonable alternative.

In addition to the quantitative aspects of the analysis, there are also the qualitative aspects to consider. The qualitative aspects to consider include changes in public policy, such as the implementation of an RPS, public acceptance, resource timing and commitment, technology

Table 6-9. Risk Analysis Summary

	20-Year Present Value ($000s)			
	F1	F2	F3	F4
Expected Portfolio Cost	$4,829,327	$5,051,302	$4,938,464	$5,054,667
Backbone Transmission Upgrade Cost[1]	$580,956	$525,737	$643,867	$394,606
CO_2 Tax Risk (from Table 6-3)	$120,364	$166,475	$189,551	$163,352
Natural Gas Price Risk (from Table 6-4)	($88,220)	($63,788)	($87,409)	($37,273)
Cost of Construction Risk (from Table 6-5)	$104,269	$153,217	$159,308	$165,986
Capital Risk (from Table 6-6)	($78,433)	($114,027)	($112,334)	($107,314)
Market Risk (from Table 6-8)	$333,109	$268,583	$292,423	$252,640
Risk Adjusted Total Portfolio Cost	$5,801,373	$5,987,499	$6,023,869	$5,886,664
Total Portfolio Cost Risk Adjusted Rank	1	3	4	2
Relative Risk Adjusted Portfolio Cost				
CO_2 Tax Risk	–	$46,111	$69,186	$42,988
Natural Gas Price Risk	–	$24,432	$811	$50,947
Cost of Construction Risk	–	$39,038	$91,212	$28,503
Capital Risk	$35,594	–	$1,693	$6,713
Market Risk	$80,469	$15,943	$39,783	–
Relative Quantified Risk	$116,063	$135,434	$166,512	$162,365
Relative Risk Ranking				
CO_2 Tax Risk	1	3	4	2
Natural Gas Price Risk	1	3	2	4
Cost of Construction Risk	1	2	3	4
Capital Risk	4	1	2	3
Market Risk	4	2	3	1
Relative Quantified Risk Ranking	1	2	4	3

[1] Transmission upgrade cost not accounted for in specific portfolio resource estimates.

risks, and regulatory risks. Considering the portfolios individually:

F1. Portfolio F1 resulted in the lowest risk-adjusted total portfolio cost, but Idaho Power has serious concerns regarding implementation of this portfolio. Portfolio F1 adds the most renewable generation, 950 MW, which may be beneficial. However, relying on a portfolio with 450 MW of geothermal resources given that there are no utility scale geothermal projects operational in Idaho may be overly optimistic. If proposals received as a result of the current geothermal RFP indicate that an abundant supply of cost-effective geothermal projects is available from qualified developers, then Idaho Power will consider increasing its reliance on geothermal generation. However, until that time, Idaho Power is reluctant to select a portfolio with 450 MW of geothermal generation. Geothermal generation will be reassessed in Idaho Power's 2008 IRP, and the quantity may be increased at that time depending on the development status of geothermal resources in Idaho.

F3. Portfolio F3 is the basic thermal portfolio. Portfolio F3 is the most carbon-intensive of the finalist portfolios and finished in second place. One of the interesting characteristics of this portfolio is its sensitivity to the carbon adder. Depending on the carbon tax scenario, Portfolio F3 has the potential to be nearly the least-expensive or the most-expensive of the resource portfolios. The fact that this portfolio can go from nearly the least- to the most-expensive portfolio based on CO_2 adder assumptions represents an unacceptable level of inherent risk. Another disadvantage of selecting Portfolio F3 is that it adds the least amount of new renewable resources and provides the least amount of protection for Idaho Power if a state or federal RPS is implemented.

F4. Portfolio F4 includes the 900 MW transmission line from Bridger to Boise. Adding the Bridger to Boise transmission line will provide the capability to integrate additional generation from the Jim Bridger Project and additional wind and geothermal resources. However, this portfolio may place an undue reliance on the Wyoming energy market. Portfolio F4 includes purchases of 525 MW from Wyoming to satisfy peak-hour needs in 2016. The Wyoming market is still a small regional electric market due to the limited number of market participants and the fact that participants in the Wyoming market may have coincident peak-hour energy needs. The limited Wyoming market may result in reduced amounts of available energy and higher prices. Idaho Power is uncomfortable with the assumption that 525 MW can be purchased during summertime peak-load hours from either the Wyoming market or the east side of its system.

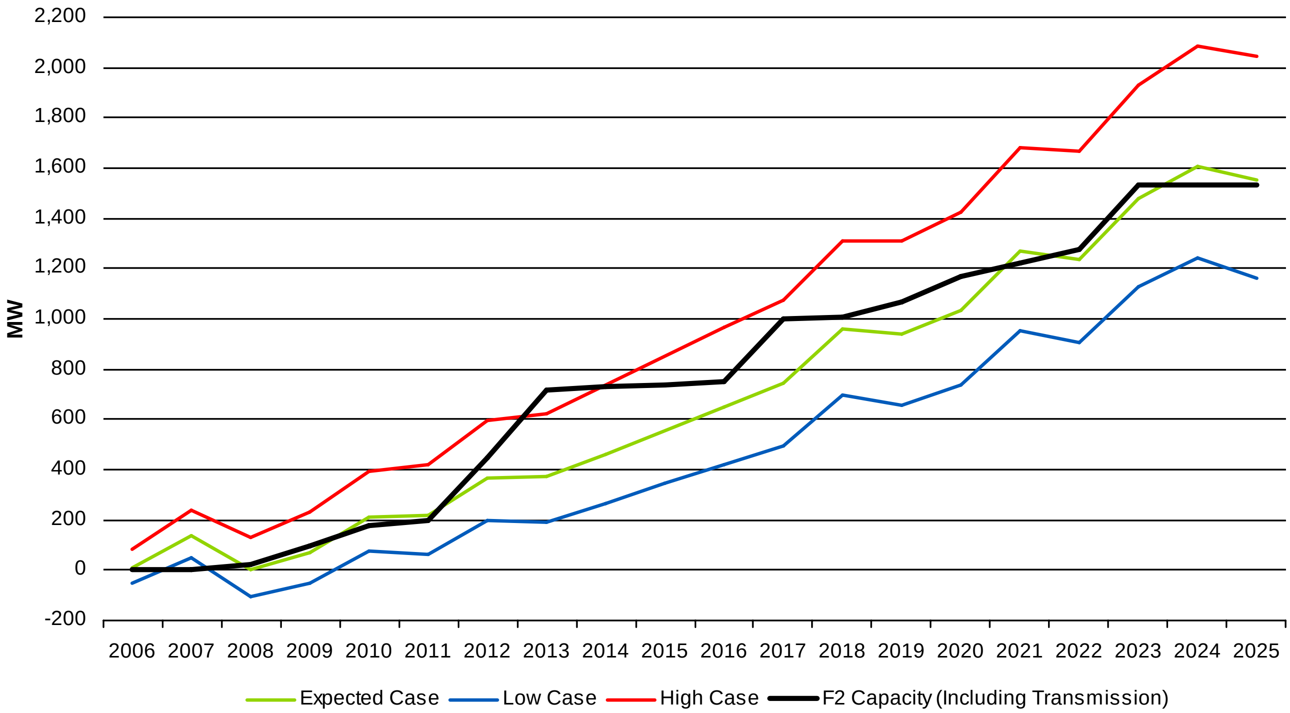
F2. Portfolio F2 is an extension of the 2004 IRP preferred portfolio. The resource configuration has been adjusted to reflect Idaho Power's current assessment of its future needs. Several of the changes address concerns expressed by the IPUC and OPUC regarding the 2004 IRP. Portfolio F2 refines both the size and timing of the 500 MW coal-fired resource originally identified in the 2004 IRP. Portfolio F2 includes 250 MW of pulverized coal in 2013 and 250 MW of IGCC in 2017. Portfolio F2 also incorporates a transmission upgrade from McNary (Mid-C) to Boise. Idaho Power has historically been able to supply summer peaking needs from the Pacific Northwest, and it recognizes that the Mid-C market is far larger and more established that the regional energy markets on the east side of its system. Idaho Power believes that Portfolio F2 provides a balanced approach to meeting future resource needs.

Figure 6-4 shows the load forecast risk under the high- and low-load growth scenarios faced by adopting Portfolio F2. Portfolio F2 closely matches the capacity required to meet the expected load forecast during the early years of the planning period. As would be the case with any large resource, adding 250 MW of coal-fired generation in 2012 leads to a temporary energy surplus during the time that Idaho Power receives the plant output.

If actual customer load turns out to be either higher or lower than the expected load forecast, then the timing and size of the resource RFPs in F2 can be adjusted to accommodate the realized customer load. Flexibility in the RFP process helps Idaho Power meet changing loads and also allows the developers to respond to the RFP with more cost-effective proposals. Idaho Power expects to offer similar flexibility in the DSM and renewable RFPs.

Portfolio F2 has a diverse mix of generation resources balanced between renewable resources and traditional thermal resources. The qualitative risks associated with policy changes, resource timing, siting, and public acceptance are difficult to forecast. However, a diverse portfolio will have less exposure to the qualitative risks considered in this IRP than will a portfolio concentrated on one resource type or one resource strategy. The risk analysis supports the conclusion that F2, with its blended approach, is Idaho Power's preferred portfolio.

Figure 6-4. Portfolio F2 (Capacity Compared to Low, Expected, and High Peak-Hour Load Forecast)



During the June 20th IRPAC meeting, the IRPAC and members of the public were asked to rate the likelihood of construction of each of the four finalist portfolios. The results indicated that F2 and F4 were judged to have the highest likelihood of construction (F2 finished just slightly ahead of F4). Given Idaho Power's supply-related concerns with F4 noted above, Idaho Power believes that Portfolio F2 is a prudent resource choice. In summary, the advantages of Portfolio F2 are:

- Provides diversification of Idaho Power's overall resource mix
- Positions Idaho Power to meet potential public policy changes (CO_2 risk and an RPS)
- Reduces the amount of near-term, coal-fired generation from 500 MW in the 2004 IRP to 250 MW
- Provides additional time for continued deployment and refinement of IGCC technology for use with western coals
- Judged by the IRPAC as having the highest likelihood of construction

Idaho Power believes the key issues to be considered in the 2006 IRP are:

- The timing and costs of potential future carbon taxes and greenhouse gas regulation
- Future natural gas prices
- Technology risks associated with new generation technologies—principally, IGCC; however, utility scale geothermal is unproven in Idaho as well
- The possibility of a federal RPS
- The ability to permit, develop, and construct generation and transmission resources in a timely manner
- The rate of future PURPA resource development is also a concern, but can

be addressed through the iterative nature of the IRP process

Idaho Power believes that Portfolio F2 outlines a balanced and flexible approach to meet future resource needs given the level of uncertainty associated with the key issues mentioned above. Idaho Power's 2006 resource strategy can be summed up as follows:

- Incorporate cost-effective DSM programs and add cost-effective renewable generation to reduce the carbon intensity of Idaho Power's resource portfolio which prepares the company in the event that carbon taxes, an RPS, or GHG regulations are enacted

- Take the steps necessary to add an increment of baseload resources (coal and transmission) to meet near-term resource needs

- Minimize technology risk by investigating opportunities to participate in a jointly-owned IGCC project in the near-term and deferring larger commitments to IGCC technology until a later date

- Maintain flexibility in the near-term plan to incorporate additional geothermal and wind resources if they are proven to be reliable and cost effective.

It is important to note that the final objective of the risk analysis is not to exactly quantify the risk associated with a portfolio. Instead, the risk analysis is designed to identify a portfolio that leads to 20-year and near-term action plans that are resilient to the different risks. The objective is to arrive at an IRP that meets the projected needs of the customers, as well as a plan that can accommodate economic and political changes at the least cost to Idaho Power and its customers. The action plans resulting from selecting Portfolio F2 are discussed in Chapters 7 and 8.

7. Ten-Year Resource Plan

Introduction

Although the planning horizon in Idaho Power's 2006 IRP has been extended to 20 years, a 10-year resource plan is provided to outline the activities necessary to implement the preferred portfolio. Because the IRP is updated biennially and a new preferred portfolio will be selected in the 2008 IRP, a detailed action plan extending beyond 10 years is unnecessary.

Portfolio F2 consists of a diversified set of supply-side and demand-side resources and has been selected as the preferred portfolio. The preferred portfolio adds supply-side and demand-side resources capable of supplying approximately 1,100 MW of average energy and 1,250 MW of capacity to meet peak-hour loads. In addition, Portfolio F2 provides 285 MW of additional transmission capacity from the Pacific Northwest. The distribution of supply-side and demand-side resources included in Portfolio F2 is shown in Table 7-1.

Selecting Portfolio F2 provides Idaho Power with a forecasted schedule of events as outlined in Table 7-2. It is important to note that this preferred portfolio selection is based on a number of forecasts and assumptions. Many factors can impact the actual timing of activities listed here and therefore, by design the 10-year resource plan incorporates a certain amount of flexibility. Idaho Power expects to use the RFP process to acquire certain supply-side resources.

Table 7-1. Portfolio F2 (Supply-Side and Demand-Side Resources)

	Nameplate Rating (MW)	Energy (aMW)	Capacity (MW)
Supply-Side	1,300	1,001	1,063
Demand-Side	187	88	187
Subtotal	1,487	1,089	1,250
Transmission	285	285	285
Total	1,772	1,374	1,535

RFPs for the first two resource additions—100 MW of wind generation and a 100 MW geothermal resource—are both underway. A successful bidder was recently announced for the wind RFP, and the geothermal RFP was released in June 2006. Both the wind and geothermal RFPs were identified in Idaho Power's 2004 IRP. Depending on the amount of PURPA wind generation developed on Idaho Power's system and the results of the wind integration study, Idaho Power expects to issue an RFP in 2009 for an additional 150 MW of wind generation.

Highlights

- The 2006 IRP includes 1,300 MW (nameplate) of supply-side resource additions to Idaho Power's resource portfolio over the 20-year planning period.
- The supply-side resource additions are expected to provide 1,001 aMW of energy and 1,063 MW of capacity.
- Not included in the totals above, Idaho Power has committed to adding a 170 MW combustion turbine in 2008 at the Danskin site and performing a 49 MW upgrade at the Shoshone Falls Hydroelectric Project in 2010.
- The 2006 IRP also includes DSM programs designed to reduce Idaho Power's average load by 88 aMW annually and the summertime peak-hour load by 187 MW.

Table 7-2. Portfolio F2 (10-Year Resource Plan)

Activity

September 2006

1. 2006 Integrated Resource Plan submitted to the Idaho and Oregon Public Utility Commissions

Fall 2006

1. Idaho Power concludes 100 MW wind RFP issued in response to the 2004 IRP
2. Notify short-listed bidders in 100 MW geothermal RFP issued in response to the 2004 IRP
3. McNary–Boise transmission upgrade process initiated
4. Develop implementation plans for new DSM programs with guidance from the EEAG
5. Continue coal-fired resource evaluation with Avista and consider expansion opportunities at Idaho Power's existing projects (Jim Bridger, Boardman and Valmy)
6. Investigate opportunities to increase participation in the highly successful Irrigation Peak Rewards DSM program
7. Complete wind integration study
8. Evaluate the Rider level to fund DSM program expansion

2007

1. Finalize DSM implementation plans and budgets with guidance from the EEAG
2. 100 MW geothermal RFP concluded
3. Assess CHP development in progress via PURPA process—consider issuing RFP for 50 MW CHP depending on level of PURPA development
4. Identify leading candidate site(s) for coal-fired resource addition and begin permitting activities
5. 225 MW McNary–Boise transmission upgrade–studies in progress
6. 100 MW wind on-line
7. Evaluate/initiate DSM programs
8. Select coal fired resource, finalize contracts, begin design, procurement, and pre-construction activities

2008

1. 225 MW McNary–Boise transmission upgrade–final commitments
2. 250 MW Borah–West transmission upgrade complete
3. 170 MW Danskin expansion on-line
4. Evaluate/initiate DSM programs
5. Prepare and file 2008 IRP

2009

1. 150 MW wind RFP issued
2. 50 MW geothermal resource on-line–possibly more depending on response to the 2006 RFP
3. Evaluate/initiate DSM programs

2010

1. 50 MW CHP on-line
2. Evaluate/initiate DSM programs
3. 49 MW Shoshone Falls upgrade on-line
4. Prepare and file 2010 IRP

2011

1. Evaluate/initiate DSM programs

2012

1. 225 MW McNary–Boise transmission upgrade complete
2. 150 MW wind on-line
3. Evaluate/initiate DSM programs
4. Prepare and file 2012 IRP

2013

1. 250 MW coal-fired generation on-line
2. Evaluate/initiate DSM programs

2014

1. Evaluate/initiate DSM programs
2. Prepare and file 2014 IRP

2015

1. Evaluate/initiate DSM programs

Idaho Power intends to work with EEAG to initiate the demand-side activities identified in the 2006 Integrated Resource Plan.

Supply-Side Resources

The 2006 IRP identifies 1,300 MW (nameplate rating) of supply-side resource additions to Idaho Power's supply-side portfolio. The new resources are expected to provide 1,001 aMW of energy and 1,063 MW of capacity. The new resources identified in the 2006 IRP do not include the 170 MW Danskin combustion turbine scheduled to be on-line in 2008, or the 49 MW Shoshone Falls upgrade, scheduled to be on-line in 2010. Both the Danskin addition and the Shoshone Falls upgrade are considered to be committed resources in Idaho Power's 2006 IRP and are not included in Portfolio F2's 1,300 MW total.

In the near-term, Idaho Power plans to add up to 100 MW of wind generation by the end of 2007 and up to 100 MW of geothermal generation in 2009. Idaho Power expects to follow the wind and geothermal additions with approximately 50 MW of CHP generation in 2010.

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 88 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.

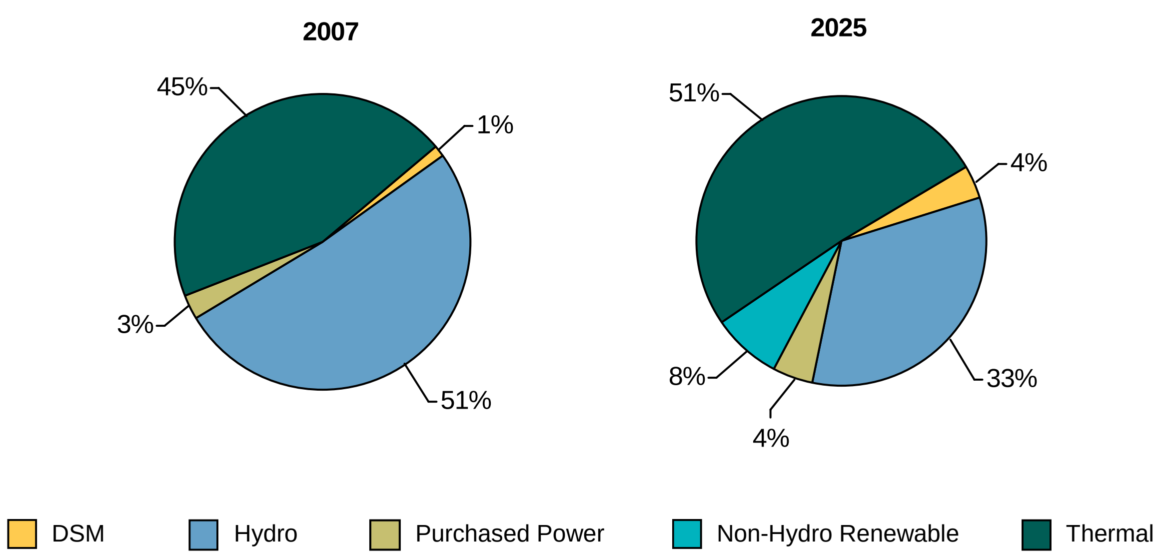
The coal-fired resource scheduled for 2013 will also require significant transmission upgrades to deliver the energy to the Treasure Valley.

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 106 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



8. Near-Term Action Plan

Introduction

Over the past 85 years, Idaho Power has developed a blended portfolio of generation resources. Idaho Power believes a portfolio of diverse generation resources is the most cost-effective and lowest-risk method to address the increasing energy demands of its customers.

New customer growth is the primary driver behind Idaho Power's need for the additional resources identified in the 2006 IRP. Population growth throughout southern Idaho and, specifically, in the Treasure Valley, requires that Idaho Power acquire new resources to meet both the peak-hour and average energy needs of its customers.

Supply-side generation resources and increasing transmission capacity to the Pacific Northwest are likely alternatives for Idaho Power to meet the increasing energy demands of its customers. However, Idaho Power's customers have expressed a desire for a balanced resource portfolio that also contains resources which are financially, environmentally, and socially responsible. Therefore, renewable energy and demand-side measures continue to be significant contributors to the resource portfolio selected in the 2006 Integrated Resource Plan.

Near-Term Action Plan

The Near-Term Action Plan presented in Table 8-1 is a forecasted schedule of events through 2008 that are associated with implementing the preferred portfolio. By design, the action plan is expected to be flexible enough to accommodate the uncertainly associated with acquiring resources through an RFP process, and the uncertainty of developing resources in cooperation with other utilities. Idaho Power may deviate from the action plan, as necessary, to achieve the goal of acquiring sufficient resources to reliably serve the growing demand for energy within Idaho Power's service area while continuing to balance cost, risk, and environmental concerns. For example, during the IRPAC meetings, members voiced concerns regarding the amount of geothermal generation contained in Portfolio F1. Although Portfolio F1 had the lowest power supply costs, it was not selected due, in part, to the IRPAC's concerns that the quantity of geothermal resources in the portfolio might be unrealistic given the lack of proven geothermal resources in Idaho. However, if geothermal resources can be developed and acquired at the costs estimated in

Highlights

- ► In the fall of 2006, Idaho Power plans to complete its wind integration study and the RFP for 100 MW of wind generation.
- ► Idaho Power plans to complete its 100 MW geothermal RFP in early 2007.
- ► During 2007 and 2008 Idaho Power expects to commit to a new coal-fired, baseload resource, and a transmission upgrade to the Pacific Northwest. These projects are expected to be completed in 2012 and 2013 respectively.
- ► Continuing with its commitment to support renewable energy through education and demonstration projects, Idaho Power intends to commit up to an additional $100,000 to support renewable energy education and demonstration projects. Areas currently under consideration include solar energy projects and river flow energy conversion devices.

Table 8-1. Portfolio F2 (Near-Term Action Plan through 2008)

Activity	
September 2006 1. 2006 Integrated Resource Plan submitted to the Idaho and Oregon Public Utility Commissions ***Fall 2006*** 1. Idaho Power concludes 100 MW wind RFP issued in response to the 2004 IRP 2. Notify short-listed bidders in 100 MW geothermal RFP issued in response to the 2004 IRP 3. McNary–Boise transmission upgrade process initiated 4. Develop finalized implementation plans for new DSM programs with guidance from the EEAG 5. Continue coal-fired resource evaluation with Avista and consider expansion opportunities at Idaho Power's existing projects (Jim Bridger, Boardman and Valmy) 6. Investigate opportunities to increase participation in the highly successful Irrigation Peak Rewards DSM program 7. Complete wind integration study 8. Evaluate the Rider level to fund DSM program expansion	***2007*** 1. Finalize DSM implementation plans and budgets with guidance from the EEAG 2. 100 MW geothermal RFP concluded 3. Assess CHP development in progress via PURPA process—consider issuing RFP for 50 MW CHP depending on level of PURPA development 4. Identify leading candidate site(s) for coal-fired resource addition and begin permitting activities 5. 225 MW McNary–Boise transmission upgrade–studies in progress 6. 100 MW wind on-line 7. Evaluate/initiate DSM programs 8. Select coal fired resource, finalize contracts, begin design, procurement, and pre-construction activities ***2008*** 1. 225 MW McNary–Boise transmission upgrade–final commitments 2. 250 MW Borah–West transmission upgrade complete 3. 170 MW Danskin expansion on-line 4. Evaluate/initiate DSM programs 5. Prepare and file 2008 IRP

Chapter 4, then Idaho Power will consider adding more geothermal resources as a part of this and future Integrated Resource Plans.

In the near-term, Idaho Power intends to continue acquiring wind resources, geothermal resources, demand-side measures, and CHP resources, and proceed with commitments to develop coal-fired and transmission resources which require a long lead time. The supply-side, demand-side, and transmission resource acquisitions and commitments may or may not meet the specific energy and capacity targets identified in the 2006 IRP. The energy and capacity values in future resource plans are likely to be modified to reflect the outcome of the RFP process, transmission studies, PURPA resource development, and operational and load growth changes that Idaho Power experiences.

During IRPAC meetings, members voiced concerns on a number of issues including the CO_2 emissions associated with conventional coal-fired resources, using IGCC in lieu of conventional pulverized coal technology, demonstrating a stronger commitment to energy efficiency and demand-side resources, and the need to take steps now to build baseload resources and to increase transmission import capacity.

Generation Resources

Thermal Generation—Baseload

The preferred portfolio identifies a 250 MW Wyoming coal-fired resource; however, specific details of the resource are yet to be determined. At present, a mine-mouth project in Wyoming or Montana appears to be the most likely alternative. Idaho Power anticipates a plant in either Montana or Wyoming would provide delivered power at approximately the same cost.

Idaho Power intends to continue its evaluation of regional coal-fired resource alternatives with Avista and other utilities. Idaho Power is also exploring development opportunities at Idaho Power's jointly-owned coal-fired facilities at Jim Bridger, Boardman, and Valmy.

In addition to investigating coal-fired resources, industrial customers have approached Idaho Power regarding CHP projects. Idaho Power intends to continue ongoing negotiations to develop these projects within its service area. If approximately 50 MW of CHP projects are not in development or under contract as a result of PURPA development by the end of 2007, Idaho Power will consider issuing a CHP RFP.

Idaho Power will need additional baseload generation to meet the future energy needs of its customers. Idaho Power has not added a baseload resource to its portfolio since the construction of the Valmy coal-fired plant in the mid-1980s. The 2004 IRP identified that the time has come to acquire additional baseload generation and the 2006 IRP refines the timing and size of the resource need. Between now and 2008, Idaho Power plans to proceed with the evaluation of coal-fired resource alternatives, select the preferred resource, and move ahead with commitments to develop additional coal-fired generation.

Thermal Generation—Peaking

Population growth in southern Idaho is driving Idaho Power's peak-hour load growth due primarily to air conditioning units being installed in most new construction. Idaho Power's peak-hour load has been growing and is projected to continue growing at approximately 80 MW per year. In the near-term, Idaho Power must continue to rely on natural gas-fired resources, such as the Bennett Mountain and Danskin Power plants, to meet the peak energy demands of its growing customer base. Idaho Power expects the 170 MW Danskin addition will be commissioned and on-line for the 2008 summer season and will be necessary to meet peak-hour loads until a new baseload resource can be constructed. As mentioned in the previous section, Idaho Power also continues to explore CHP projects with its industrial customers and anticipates the addition of a CHP project will contribute to summer peak-hour generation.

Renewable Energy

In the 2004 IRP, Idaho Power committed to fund education and demonstration energy projects with up to $100,000 of funding. One of the projects supported with this commitment was the Foothills Environmental Learning Center in north Boise. Idaho Power's support for this project included installation of a 4.6 kW fuel cell and a 2.0 kW solar panel. Another project undertaken in the past two years was the repair and upgrade of the 15 kW solar energy project on the roof of Idaho Power's corporate headquarters in downtown Boise.

Continuing with its commitment to support renewable energy through education and demonstration projects, Idaho Power intends to commit up to an additional $100,000 to support renewable energy education and demonstration projects. Areas currently under consideration include solar energy projects and river flow energy conversion devices. At present, Idaho Power has not selected a specific project(s) to pursue with this funding.

Idaho Power's commitment to renewable resources is evident in its intent to add a significant quantity of renewable energy to its generation portfolio. Idaho Power has targeted to add 400 MW of renewable wind and geothermal resources during the 20-year planning period contained in the 2006 IRP. If the RFP process indicates additional supply is available at favorable prices, Idaho Power may further increase the amount of renewable resources in its generation portfolio. Renewable resources continue to show favorably in the resource portfolio analysis; however, the IRPAC expressed concerns about the quantity of renewable resources available in southern Idaho. The contribution of renewable resources will continue to be assessed and discussed as part of the 2008 and 2010 Integrated Resource Plans.

Wind Generation

Idaho Power issued an RFP for approximately 200 MW of wind generation in early 2005. However, beginning in late 2004, PURPA developers requested contracts to supply a significant amount of wind generation and Idaho Power was uncertain as to the effects it would have on its system. On June 17, 2005, Idaho Power filed a petition with the IPUC requesting that the IPUC temporarily suspend its obligation to purchase wind generation from qualified facilities. On June 30, 2005, Idaho Power temporarily suspended activity on the wind RFP while waiting for the IPUC to issue a ruling on its petition. On August 4, 2005, the IPUC issued an order reducing the rate cap for published avoided costs from 10 aMW to 100 kW. On September 28, 2005, the wind RFP was resumed and, on July 6, 2006, Idaho Power announced the selection of a successful bidder. The proposed project is expected to be on-line in late 2007 and will add an additional 66 MW of wind energy to Idaho Power's power supply portfolio. In addition to the 2005 wind RFP, Idaho Power has signed agreements for over 200 MW of PURPA wind generation.

A number of viable wind generation sites and projects are under development in southern Idaho. In addition to the nearly 300 MW of wind generation expected to be on-line by 2010, the preferred portfolio includes an additional 150 MW of wind generation in 2012. Depending on the results of the wind integration study, the level of PURPA development, and the available supply of low-cost wind, Idaho Power will consider either increasing or decreasing the amount of wind generation in its resource portfolio in the 2008 and 2010 Integrated Resource Plans.

Geothermal Generation

Idaho Power issued an RFP for 100 MW of geothermal generation in June 2006. Similar to wind resources, Idaho Power recognizes geothermal generation has moved beyond the research and development stage and plans to incorporate geothermal resources into its generation portfolio. Geothermal developers have indicated there are several viable geothermal generation sites in southern Idaho. In anticipation of responses to the current RFP for 100 MW of geothermal generation, the preferred portfolio includes 50 MW of geothermal generation targeted to be on-line in 2009. However, if sufficient quantities of geothermal generation are available from qualified developers at competitive prices, Idaho Power will consider acquiring additional geothermal resources in the near-term. Depending on the success of the geothermal generation projects, geothermal generation may play a greater role in future resource portfolios.

Transmission Resources

In addition to the two specific transmission projects identified in the 2006 IRP, the 225 MW McNary to Boise line and the 60 MW Lolo to Brownlee upgrade, additional transmission system upgrades internal to Idaho Power's system will be necessary to integrate the new resources identified in the 2006 IRP. Idaho Power expects the Borah–West transmission path upgrades identified in the 2004 IRP to be completed in May 2007. The planned Borah–West upgrades which are necessary to integrate generation resources located on the eastern side of Idaho Power's service area, will also increase the ability to import power from markets east of Idaho. Idaho Power will continue to evaluate the transmission requirements of the resources proposed in the 2006 IRP and consider the impact in future Integrated Resource Plans.

Demand-Side Management

Idaho Power is working with the EEAG (comprised of customer, special interest, and PUC representatives from Idaho and Oregon) to design a package of DSM programs that will reduce average loads by 88 aMW and summertime peak-hour loads by 187 MW.

Idaho Power developed its DSM energy savings estimates for the proposed residential and commercial programs based on a detailed study of potential savings which was conducted by Quantum Consulting Company. The proposed industrial program savings estimates were developed by Idaho Power by performing an engineering and marketing analysis.

Idaho Power anticipates the new energy efficiency programs coming on-line in 2007 and continuing throughout the planning period. As a part of the DSM management process, program performance is continuously monitored and evaluated for improvements. The analysis and results of all demand-side programs are reported annually in the DSM Annual Report and more frequently to the EEAG.

Risk Mitigation

Idaho Power's near-term action plan includes additional renewable resources, CHP, DSM programs, a commitment to develop a coal-fired resource, and expand transmission capacity to the Pacific Northwest. The action plan also specifically incorporates the flexibility to acquire more wind and geothermal generation if it can be acquired at competitive prices. Conversely, if the cost of wind and geothermal resources are not competitive, lesser amounts may be acquired. The amount of wind generation Idaho Power can integrate into its system will be limited by operational constraints and economics. As noted earlier, Idaho Power is conducting a wind integration study to determine the cost of integrating wind generation at several different penetration levels. This study is expected to be completed in the fall of 2006.

A diverse portfolio of planned resources helps to reduce some of the larger risks Idaho Power faces in the development of its future resources. The possibility of future CO_2 regulations, the technological risks of developing IGCC generation, the realization risk associated with developing renewable wind and geothermal resources, and the realization risk associated with customer-based demand-side programs could each have an impact on Idaho Power's plan to acquire future resources.

Because Idaho Power files an updated IRP every two years, there is a certain amount of flexibility inherent in the IRP process. Resources identified in the long-term plan may change in future IRPs depending on the outcome of the previously mentioned risk factors. And while the addition of certain resources such as wind and geothermal do not require substantial lead times, transmission and coal-fired resources require substantial lead times and an early commitment and will be subject to a greater amount of risk. The diverse nature of the near-term action plan in Idaho Power's 2006 IRP will mitigate the overall risk associated with acquiring additional resources.

Although renewable resources and demand-side programs face no fuel price risk, there are other risks associated with renewable resources. Geothermal resources are unproven in Idaho, and the economic viability of both wind and geothermal generation is driven by the federal PTCs at the present time. Idaho Power has received considerable interest from geothermal resource developers, but until the responses to the geothermal RFP are received and evaluated, it is difficult to assess the available supply and cost effectiveness of geothermal resources. Likewise with demand-side programs, until responses to the RFPs have been received, the programs implemented, and the results measured, it is difficult to estimate the actual performance of the programs.

In 2006, Idaho Power expects to finalize negotiations for adding additional wind generation and evaluate the responses to the geothermal RFP. The geothermal RFP is expected to be awarded in early 2007 and result in at least 50 MW of geothermal generation coming on-line in 2009. Idaho Power will also continue to investigate coal-fired resource development with potential partners during the remainder of 2006 and 2007. It is likely Idaho Power will enter into a firm commitment in 2007 or 2008 to participate in a coal-fired resource expected to be on-line in 2013. Idaho Power will complete engineering studies and enter into commitments to expand the transmission import capacity from the Pacific Northwest during the next few years. Idaho Power will also work with the EEAG to implement the DSM programs that are expected to reduce average loads by 88 aMW and peak-hour loads by 187 MW.

The DSM energy savings targets developed in the IRP are independent from energy savings that might be associated with future state and local building code modifications, market transformation energy savings such as those supported by Idaho Power through the Alliance, and other activities outside of Idaho Power’s DSM programs. Because all of these components comprise the total conservation savings in Idaho Power’s service area, the potential exists for differences in how reported savings are calculated. Idaho Power and the EEAG are committed to developing successful DSM programs that represent verifiable and meaningful savings for Idaho Power’s customers.

Idaho Power prepares an Integrated Resource Plan biennially. At the time of the next plan in 2008, Idaho Power will have additional information regarding the cost and availability of renewable resources, demand-side programs, fuel prices, economic conditions, and load growth. In addition, Idaho Power hopes to have better information regarding potential carbon regulations, the feasibility of IGCC, and the development of a federal RPS.

One of the key strengths of Idaho Power’s planning process is that the IRP is updated every two years. Frequent planning allows Idaho Power, the Idaho and Oregon PUCs, and concerned customers (including the IRPAC) to revisit the resource plan and make periodic adjustments and corrections to reflect changes in technology, economic conditions, and regulatory requirements. During the two years between resource plan filings, the public and regulatory oversight of the activities identified in the near-term action plan allows for discussion and adjustment of the IRP as warranted.