IDAHO POWER®
An IDACORP Company

June 2015

Integrated Resource Plan 2015

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 Idaho Power's filings with the Securities and Exchange Commission.

June 2015

Integrated Resource Plan 2015

ACKNOWLEDGMENT

Resource planning is an ongoing process at Idaho Power. Idaho Power prepares, files, and publishes an Integrated Resource Plan every two years. Idaho Power expects that the experience gained over the next few years will likely modify the 20-year resource plan presented in this document.

Idaho Power invited outside participation to help develop the *2015 Integrated Resource Plan*. Idaho Power values the knowledgeable input, comments, and discussion provided by the Integrated Resource Plan Advisory Council and other concerned citizens and customers.

It takes approximately one year for a dedicated team of individuals at Idaho Power to prepare the Integrated Resource Plan. The Idaho Power team is comprised of individuals that represent many different departments within the company. The Integrated Resource Plan team members are responsible for preparing forecasts, working with the advisory council and the public, and performing all the analyses necessary to prepare the resource plan.

Idaho Power looks forward to continuing the resource planning process with customers, public interest groups, regulatory agencies, and other interested parties. You can learn more about the Idaho Power resource planning process at www.idahopower.com.

Printed on recycled paper

TABLE OF CONTENTS

Table of Contents i

List of Tables vi

List of Figures viii

List of Appendices x

Glossary of Acronyms xi

1. Summary 1

Introduction 1

Public Advisory Process 2

IRP Methodology 3

Greenhouse Gas Emissions 4

Proposed Pilot Projects 6

Solar Photovoltaic to Address Distribution Feeder Voltage Loss 6

Ice-Based Thermal Energy Storage 6

Community Solar 6

Portfolio Analysis Summary 8

North Valmy and Jim Bridger Coal Unit Early Retirement and CAA Section 111(d) Regulation 8

Uncertainty Related to PURPA Solar 9

Boardman to Hemingway Transmission 9

Selection of the Preferred Portfolio 10

Action Plan 10

Action plan (2015–2018) 10

2. Political, Regulatory, and Operational Issues 13

Idaho Energy Plan 13

Idaho Strategic Energy Alliance 13

FERC Relicensing 14

Idaho Water Issues 15

Renewable Integration Study 18
Northwest Power Pool Energy Imbalance Market 19
Renewable Energy Certificates 20
Renewable Portfolio Standard 21
REC Management Plan 21
Federal Energy Legislation CAA Section 111(d) 21
3. Idaho Power Today 23
Customer Load and Growth 23
2014 Energy Sources 25
Existing Supply-Side Resources 27
Hydroelectric Facilities 28
Coal Facilities 32
Natural Gas Facilities 32
Solar Facilities 33
Power Purchase Agreements 34
Public Utility Regulatory Policies Act 35
Wholesale Contracts 37
Market Purchases and Sales 38
4. Demand-Side Resources 39
Introduction 39
Demand-Side Management Program Overview 39
DSM Planning Changes from the 2013 IRP 40
Program Screening 41
DSM Program Performance 41
Energy Efficiency Performance 41
Demand Response Performance 42
Committed Energy Efficiency Forecast 43
Committed Demand Response Resources 46

Non-Cost-Effective DSM Resource Options 46
Additional Demand Response 47
Energy Efficiency Working Group 47
Conservation Voltage Reduction 48
5. Supply-Side Generation and Storage Resources 49
Renewable Resources 49
Solar 49
Geothermal 51
Hydroelectric 52
Wind 53
Biomass 53
Conventional Resources 53
Natural Gas-Fired Resources 54
Nuclear Resources 56
Coal Resources 56
Storage Technologies 57
Battery Storage 58
Ice-Based Thermal Energy Storage 58
Pumped Storage 59
6. Transmission Planning 61
Past and Present Transmission 61
Transmission Planning Process 62
Local Transmission Planning Process 62
Regional Transmission Planning 63
Interconnection-Wide Transmission Planning 63
Existing Transmission System 63
Idaho–Northwest Path 64
Brownlee East Path 64

Idaho–Montana Path 65
Borah West Path 65
Midpoint West Path 65
Idaho–Nevada Path 65
Idaho–Wyoming Path 66
Idaho–Utah Path....66
Boardman to Hemingway 66
Gateway West 69
Gateway West Need Analysis....70
Transmission Assumptions in the IRP Portfolios 71
7. Planning Period Forecasts....73
Load Forecast....73
Weather Effects....74
Economic Effects 74
Peak-Hour Load Forecast 76
Average-Energy Load Forecast 78
Additional Firm Load 79
Generation Forecast for Existing Resources....80
Hydroelectric Resources 80
Coal Resources....83
Coal Analysis 83
Natural Gas Resources 84
Natural Gas Price Forecast....84
Resource Cost Analysis 85
Resource Cost Analysis II—Resource Stack....86
Levelized Capacity (Fixed) Cost 86
Levelized Cost of Production....86
Supply-Side Resource Costs 90

Load and Resource Balance 92

8. Portfolio Selection 97

Portfolio Design 97

Portfolio Design and Selection 98

Status Quo Portfolio 98

Maintain Coal Capacity Portfolios 99

North Valmy Retirement Year-End 2019 Portfolios 100

North Valmy Retirement Year-End 2025 Portfolios 103

North Valmy Staggered Retirement Year-End 2019 (Unit 1) and Year-End 2025 (Unit 2) Portfolios 104

Jim Bridger Staggered Retirement Year-End 2023 (Unit 1) and Year-End 2032 (Unit 2) Portfolios 105

Jim Bridger Staggered Retirement Year-End 2023 (Unit 1) and Year-End 2028 (Unit 2) Portfolio 106

Jim Bridger Staggered Retirement Year-End 2023 (Unit 1) and Year-End 2032 (Unit 2), North Valmy Retirement Year-End 2025 Portfolio 107

Alternative to B2H Portfolios 107

North Valmy Staggered Retirement Year-End 2021 (Unit 1) and Year-End 2025 (Unit 2) Portfolio 110

Portfolio Design Summary 111

9. Modeling Analysis and Results 113

CAA Section 111(d) Sensitivity Analysis 114

Null Sensitivity (no CAA Section 111(d)) 114

State-by-State Mass-Based Compliance 114

System-Wide Mass-Based Compliance 115

Emissions-Intensity Compliance Using the EPA's Compliance Building Blocks 115

Baseline CAA Section 111(d) 116

CAA Section 111(d) Sensitivity Analysis Results 118

Stochastic Risk Analysis 121

Portfolio Cost-Assessment of Year-to-Year Variability 123

Tipping-Point Analysis 124
Portfolio Emissions 125
Qualitative Risk Analysis 125
Existing Generation 126
New Generation 127
Preferred Portfolio 130
Analysis of Shoshone Falls Upgrade 130
Capacity Planning Margin 131
Flexible Resource Needs Assessment 135
Loss of Load Expectation 139
10. Preferred Portfolio and Action Plan 141
Preferred Portfolio (2015–2034) 141
Action Plan (2015–2018) 141
Conclusion 143

LIST OF TABLES

Table 1.1 Community solar model comparison 7
Table 1.2 Action plan (2015–2018) 11
Table 2.1 Phase I measures included in the ESPA CAMP 17
Table 3.1 Historical capacity, load, and customer data 24
Table 3.2 Existing resources 28
Table 3.3 Net metering service customer count and generation capacity as of May 1, 2015 33
Table 4.1 Current demand response programs 2014 performance 42
Table 4.2 Total energy efficiency portfolio forecasted effects (2015–2034) (aMW) 45
Table 4.3 Total energy efficiency portfolio cost-effectiveness summary 45
Table 5.1 Solar capacity credit values 51
Table 6.1 Available transmission import capacity 66

Table 6.2 B2H capacity and permitting cost allocation 67

Table 6.3 Transmission assumptions 72

Table 7.1 Load forecast—peak hour (MW) 77

Table 7.2 Load forecast—average monthly energy (aMW) 79

Table 7.3 July monthly average energy deficits (average MW) by coal future with existing and committed supply- and demand-side resources (70th-percentile water and 70th-percentile load) 95

Table 7.4 December monthly average energy deficits (average MW) by coal future with existing and committed supply- and demand-side resources (70th-percentile water and 70th-percentile load) 95

Table 7.5 July monthly peak-hour capacity deficits (MW) by coal future with existing and committed supply- and demand-side resources (90th-percentile water and 95th-percentile load) 96

Table 7.6 December monthly peak-hour capacity deficits (MW) by coal future with existing and committed supply- and demand-side resources (90th-percentile water and 95th-percentile load) 96

Table 8.1 Fixed-cost impacts of coal retirement 98

Table 8.2 Resource portfolio P1 99

Table 8.3 Resource portfolio P2(a) 99

Table 8.4 Resource portfolio P2(b) 99

Table 8.5 Resource portfolio P2(c) 100

Table 8.6 Resource portfolio P3 100

Table 8.7 Resource portfolio P4(a) 101

Table 8.8 Resource portfolio P4(b) 101

Table 8.9 Resource portfolio P4(c) 102

Table 8.10 Resource portfolio P5 102

Table 8.11 Resource portfolio P6 103

Table 8.12 Resource portfolio P6(b) 103

Table 8.13 Resource portfolio P7 104

Table 8.14 Resource portfolio P8 104

Table 8.15 Resource portfolio P9 105

Table 8.16 Resource portfolio P10 105
Table 8.17 Resource portfolio P11 106
Table 8.18 Resource portfolio P12 107
Table 8.19 Resource portfolio P13 107
Table 8.20 Resource portfolio P14 108
Table 8.21 Resource portfolio P15 108
Table 8.22 Resource portfolio P16 109
Table 8.23 Resource portfolio P17 109
Table 8.24 Resource portfolio P18 110
Table 8.25 Resource portfolio scenario summary 111
Table 9.1 Financial assumptions 114
Table 9.2 Proposed target reductions for state-by-state mass-based compliance (IPC share) 115
Table 9.3 2015 IRP portfolios, NPV years 2015–2034 ($ thousands) (portfolios in green were studied in the stochastic risk analysis) 117
Table 9.4 Portfolio costs by CAA Section 111(d) sensitivity ($ millions) 119
Table 9.5 First peak-hour capacity deficit effects of removing 141 MW of solar PURPA 128
Table 9.6 Capacity planning margin 133
Table 10.1 Action plan (2015–2018) 142

LIST OF FIGURES

Figure 1.1 CO_2 emissions intensity of the largest 100 utilities 4
Figure 1.2 CO_2 emissions of the largest 100 utilities 5
Figure 2.1 Brownlee historical and 2015 to 2034 forecasted April to July inflow 18
Figure 3.1 Historical capacity, load, and customer data 24
Figure 3.2 2014 Idaho Power system nameplate by fuel type (MW) (owned resources plus purchased power) 26
Figure 3.3 2014 energy by source 26

Figure 3.4 2014 power purchases by fuel type 27
Figure 3.5 PURPA contracts by resource type 36
Figure 4.1 Cumulative energy efficiency savings, 2002–2014 (aMW) 42
Figure 4.2 Demand response peak reduction capacity and IRP targets, 2004–2014 (MW) 43
Figure 6.1 Idaho Power transmission system map 64
Figure 6.2 B2H routes with the agency-preferred alternative 68
Figure 6.3 Gateway West Map 69
Figure 6.4 Midpoint West Historical Utilization 71
Figure 7.1 Peak-hour load-growth forecast (MW) 77
Figure 7.2 Average monthly load-growth forecast (aMW) 78
Figure 7.3 Brownlee historical and forecast inflows 82
Figure 7.4 Henry Hub price forecast—EIA *Annual Energy Outlook 2014* (nominal dollars) 85
Figure 7.5 30-year levelized capacity (fixed) costs 88
Figure 7.6 30-year levelized cost of production (at stated capacity factors) 89
Figure 7.7 Capacity cost of new supply-side resources, online 2020 90
Figure 7.8 Energy cost of new supply-side resources 91
Figure 9.1 Portfolio stochastic analysis 122
Figure 9.2 Exceedance graph of standard deviations 124
Figure 9.3 Tipping-point analysis results 125
Figure 9.4 Flexibility need (500 MW solar, existing wind, 1% likelihood) 135
Figure 9.5 System regulation 136
Figure 9.6 Regulation violations, spring 2012 137
Figure 9.7 Regulation violations, summer 2012 137
Figure 9.8 Regulation violations, fall 2011 138
Figure 9.9 Regulation violations, winter 2011/2012 138
Figure 9.10 LOLE (hours per year) 140

LIST OF APPENDICES

Appendix A—Sales and Load Forecast

Appendix B—Demand-Side Management 2014 Annual Report

Appendix C—Technical Appendix

GLOSSARY OF ACRONYMS

AC—Alternating Current

A/C—Air Conditioning

AEG—Applied Energy Group

AFUDC—Allowance for Funds Used During Construction

AgI—Silver Iodide

akW—Average Kilowatt

AMI—Advanced Metering Infrastructure

aMW—Average Megawatt

ANSI—American National Standards Institute

ATC—Available Transmission Capacity

B2H—Boardman to Hemingway

BLM—Bureau of Land Management

BPA—Bonneville Power Administration

CAA—*Clean Air Act of 1970*

CAMP—Comprehensive Aquifer Management Plan

CBM—Capacity Benefit Margin

CCCT—Combined-Cycle Combustion Turbine

CERCLA—*Comprehensive Environmental Response, Compensation and Liability Act of 1980*

cfs—Cubic Feet per Second

CHP—Combined Heat and Power

CHQ—Corporate headquarters

Clatskanie PUD—Clatskanie People's Utility District

CO_2—Carbon Dioxide

CREP—Conservation Reserve Enhancement Program

CSPP—Cogeneration and Small-Power Producers

CVR—Conservation Voltage Reduction

CWA— *Clean Water Act of 1972*

DC—Direct Current

DOE—Department of Energy

DSM—Demand-Side Management

EEAG—Energy Efficiency Advisory Group

EIA—Energy Information Administration

EIM—Energy Imbalance Market

EIS—Environmental Impact Statement

EPA—Environmental Protection Agency

ESA—*Endangered Species Act of 1973*

ESPA—Eastern Snake River Plain Aquifer

ESPAM—Enhanced Snake River Plain Aquifer Model

F—Fahrenheit

FCRPS—Federal Columbia River Power System

FERC—Federal Energy Regulatory Commission

FLA—Final License Agreement

FPA—*Federal Power Act of 1920*

FWS—US Fish and Wildlife Service

GWh—Gigawatt-Hour

HCC—Hells Canyon Complex

Hg—Mercury

HRSG—Heat Recovery Steam Generator

IGCC—Integrated Gasification Combined Cycle

INL—Idaho National Laboratory

IPUC—Idaho Public Utilities Commission

IRP—Integrated Resource Plan

IRPAC—IRP Advisory Council

IWRB—Idaho Water Resource Board

kV—Kilovolt

kW—Kilowatt

kWh—Kilowatt-Hour

LED—Light-Emitting Diode

LOLE—Loss of Load Expectation

LTP—Local Transmission Plan

LOLP—Loss of Load Probability

m^2—Square Meters

MOU—Memorandum of Understanding

MSA—Metropolitan Statistical Area

MW—Megawatt

MWh—Megawatt-Hour

NEEA—Northwest Energy Efficiency Alliance

NEPA—*National Environmental Policy Act of 1969*

NERC—North American Electric Reliability Corporation

NO_x—Nitrogen Oxide

NTTG—Northern Tier Transmission Group

NPV—Net Present Value

NWPCC—Northwest Power and Conservation Council

NWPP—Northwest Power Pool

NREL—National Renewable Energy Laboratory

O&M—Operation and Maintenance

OATT—Open Access Transmission Tariff

ODEQ—Oregon Department of Environmental Quality

ODOE—Oregon Department of Energy

OER—Idaho Governor's Office of Energy Resources

OPUC—Public Utility Commission of Oregon

ORS—Oregon Revised Statue

pASC—Preliminary Application for Site Certificate

PCA—Power Cost Adjustment

PM&E—Protection, Mitigation, and Enhancement

PGE—Portland General Electric

PPA—Power Purchase Agreement

PURPA—*Public Utility Regulatory Policies Act of 1978*

PV—Photovoltaic

Q/A—Quality Assurance

QF—Qualifying Facility

RAAC—Resource Adequacy Advisory Committee

RCRA—*Resource Conservation and Recovery Act of 1976*

REC—Renewable Energy Certificate

RES—Renewable Electricity Standard

RFP—Request for Proposal

RH BART—Regional Haze Best Available Retrofit Technology

ROI—Return on Investment

ROR—Run-of-River

RPS—Renewable Portfolio Standard

SCCT—Simple-Cycle Combustion Turbine

SCED—Security-Constrained Economic Dispatch

SCR—Selective Catalytic Reduction

SNCR—Selective Non-Catalytic Reduction

SO_2—Sulfur Dioxide

SPE—Special-Purpose Entity

SRBA—Snake River Basin Adjudication

SRPM—Snake River Planning Model

TEPPC—Transmission Expansion Planning Policy Committee

TES—Thermal Energy Storage

TRC—Total Resource Cost

TSCA—*Toxic Substances Control Act of 1976*

USACE—United States Army Corps of Engineers

UAMPS—Utah Associated Municipal Power Systems

US—United States

USBR—Bureau of Reclamation

USFS—United States Forest Service

VRB—Vanadium Redox-Flow Battery

WECC—Western Electricity Coordinating Council

This page left blank intentionally.

1. SUMMARY

Introduction

The *2015 Integrated Resource Plan* (IRP) is Idaho Power's 12th resource plan prepared to fulfill the regulatory requirements and guidelines established by the Idaho Public Utilities Commission (IPUC) and the Public Utility Commission of Oregon (OPUC). Idaho Power's resource planning process has four primary goals:

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

2. Ensure the selected resource portfolio balances cost, risk, and environmental concerns.

3. Give equal and balanced treatment to supply-side resources, demand-side measures, and transmission resources.

4. Involve the public in the planning process in a meaningful way.

The 2015 IRP evaluates the 20-year planning period from 2015 through 2034. During this period, load is forecasted to grow by 1.2 percent per year for average energy demand and 1.5 percent per year for peak-hour demand. Total customers are expected to increase to 711,000 by 2034 from 515,000 in 2014. Additional company-owned resources will be needed to meet these increased demands.

Idaho Power owns and operates 17 hydroelectric projects, 3 natural gas-fired plants, 1 diesel-powered plant, and shares ownership in 3 coal-fired facilities. Hydroelectric generation is a large part of Idaho Power's generation fleet; however, hydroelectric plants are subject to variable water and weather conditions. Public and regulatory input encouraged Idaho Power to adopt more conservative planning criteria beginning with the 2002 IRP. Idaho Power continues to develop more conservative streamflow projections and planning criteria for use in resource adequacy planning. Idaho Power has an obligation to serve customer loads regardless of water and weather conditions. Further discussion of Idaho Power's IRP planning criteria can be found in Chapter 7.

Other resources used in the planning include demand-side management (DSM) and transmission lines. The goal for DSM programs is to achieve prudent, cost-effective energy efficiency savings and provide an optimal amount of peak reduction from demand response programs. Idaho Power also strives to provide customers with tools and information to help them manage their own energy usage. The company achieves these objectives through the implementation and careful management of incentive programs and through outreach and education.

The Idaho Power resource planning process also evaluates additional transmission capacity as a resource alternative to serve retail customers. Transmission projects are often regional resources, and their planning is conducted by regional industry groups, such as the Western Electricity Coordinating Council (WECC) and the Northern Tier Transmission Group (NTTG).
Idaho Power coordinates local transmission planning with the regional forums as well as the

Federal Energy Regulatory Commission (FERC). Idaho Power is obligated under FERC regulations to plan and expand its local transmission system to provide requested firm transmission service to third parties and to construct and place in service sufficient transmission capacity to reliably deliver energy and capacity to network customers[1] and Idaho Power retail customers.[2] Timing of new transmission projects is subject to complex permitting, siting, and regulatory and partner coordination.

IRPs address Idaho Power's long-term resource needs. Idaho Power plans for near-term energy and capacity needs in accordance with the *Energy Risk Management Policy and Standards*. The risk management standards were collaboratively developed in 2002 between Idaho Power, IPUC staff, and interested customers (IPUC Case No. IPC-E-01-16). The *Energy Risk Management Policy and Standards* specifies an 18-month period, and Idaho Power assesses the resulting operations plan monthly.

Public Advisory Process

Idaho Power has involved representatives of the public in the resource planning process since the early 1990s. The public forum is known as the IRP Advisory Council (IRPAC). The IRPAC generally meets monthly during the development of the resource plan, and the meetings are open to the public. Members of the council include political, environmental, and customer representatives, as well as representatives of other public-interest groups. Many members of the public also participate even though they are not members of the IRPAC. Some individuals have participated in Idaho Power's resource planning process for over 20 years. A list of the 2015 IRPAC members can be found in *Appendix C—Technical Appendix*.

For the 2015 IRP, Idaho Power conducted 12 IRPAC meetings, including a resource portfolio design workshop. Public working group meetings to address the specific topics of energy efficiency, solar resources, and the study of coal resources were also held.

The IRPAC visits Swan Falls Dam.

In addition, Idaho Power hosted a field trip to the Swan Falls Hydroelectric Project (Swan Falls Project) for participants of the IRP process. Idaho Power personnel leading the field trip shared information on many topics,

[1] Idaho Power has a regulatory obligation to construct and provide transmission service to network or wholesale customers pursuant to a FERC tariff.

[2] Idaho Power has a regulatory obligation to construct and operate its system to reliably meet the needs of native load or retail customers.

including high-voltage transmission, recreation, avian biology, archaeology, and Snake River water supply. Field trip participants were led on a tour of the Swan Falls power plant and the Swan Falls museum.

Idaho Power believes working with members of the IRPAC and the public improves the IRP. Idaho Power and the members of the IRPAC recognize that final decisions on the resource plan are made by Idaho Power. However, Idaho Power encourages IRPAC members and members of the public to submit comments expressing their views regarding the 2015 IRP and the resource planning process in general.

Following the filing of the final resource plan, Idaho Power presents the resource plan at public meetings in various communities around the company's service area. In addition, Idaho Power staff present the plan and discuss the planning process with various civic groups and at educational seminars as requested.

IRP Methodology

Preparation of the Idaho Power 2015 IRP began with the forecast of future customer demand. Existing generation resources, demand-side resources, and transmission import capacity were combined with customer demand to create a load and resource balance for energy and capacity. Idaho Power then evaluated new energy efficiency programs and the expansion of existing programs to revise energy and capacity deficits. Finally, Idaho Power designed and analyzed supply-side and transmission resource portfolios to address the remaining energy and capacity deficits.

Idaho Power evaluates resources and resource portfolios using a financial analysis. Idaho Power evaluates the costs and benefits of each resource type. The financial costs include construction, fuel, operation and maintenance (O&M), transmission upgrades, and anticipated environmental controls and emission costs. The financial benefits include economic resource operations, projected market sales, and the market value of renewable energy certificates (REC).

Idaho Power is part of the larger northwestern and western regional energy markets, and market prices are an important component of evaluating energy purchases and sales. Idaho Power faces transmission import constraints and at times of peak customer load must rely on its own generation resources regardless of regional market prices. Likewise, there are times when the generation connected to the Idaho Power system exceeds customer demand and the transmission export capacity, and the company must curtail generation on its system.

An additional transmission connection to the Pacific Northwest has been part of the Idaho Power preferred resource portfolio since the 2006 IRP. By the 2009 IRP, Idaho Power determined the approximate configuration and capacity of the transmission line, and since 2009 the addition has been called the Boardman to Hemingway (B2H) Transmission Line Project. Idaho Power again evaluated the B2H transmission line in the 2015 resource plan to ensure the transmission addition remains a prudent resource acquisition.

Similar to the 2013 IRP, Idaho Power analyzed various resource portfolios over the entire 20-year planning period in the 2015 IRP. The analyzed portfolios in the 2015 IRP add resources

under certain scenarios as early as 2020; consequently, Idaho Power determined it is practical to again consider the 20-year planning period in total.

Greenhouse Gas Emissions

Idaho Power owns and operates 17 hydroelectric projects, 3 natural gas-fired plants, 1 diesel-powered plant, and shares ownership in 3 coal-fired facilities. Idaho Power's carbon dioxide (CO_2) emission levels have historically been well below the national average for the 100 largest electric utilities in the United States (US), both in terms of total CO_2 emissions (tons) and CO_2 emissions intensity (pounds per megawatt-hour [MWh] generation). According to a May 2014 collaborative report using publicly reported 2012 generation and emissions data, Idaho Power and Ida-West Energy (a non-regulated subsidiary of IDACORP, Inc.) together ranked as the 38th lowest emitter of CO_2 per MWh produced and the 36th lowest emitter of CO_2 by tons of emissions among the nation's 100 largest electricity producers (figures 1.1 and 1.2).[3] According to the report, out of the 100 companies named, Idaho Power and Ida-West Energy together ranked as the 52nd largest power producer based on fossil fuel, nuclear, and renewable energy facility total electricity generation.

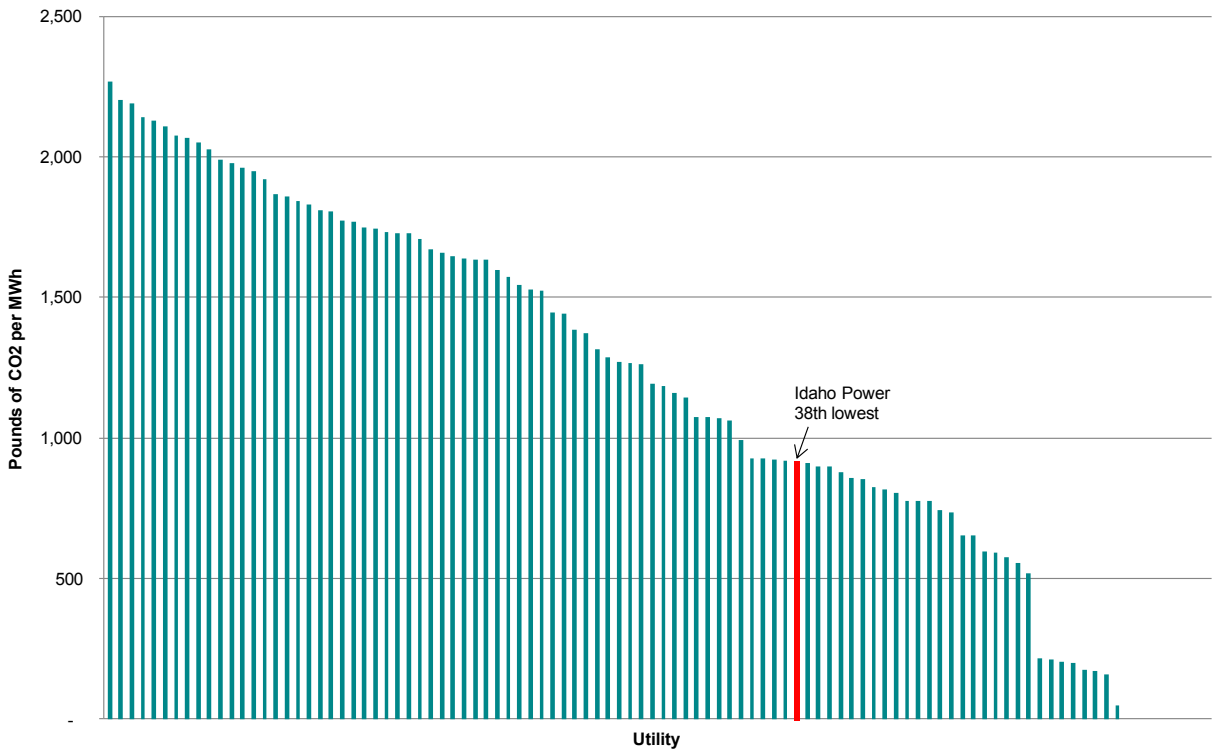


Figure 1.1 CO_2 emissions intensity of the largest 100 utilities

[3] M. J. Bradley & Associates. 2014. Benchmarking air emissions of the 100 largest electric power producers in the United States.

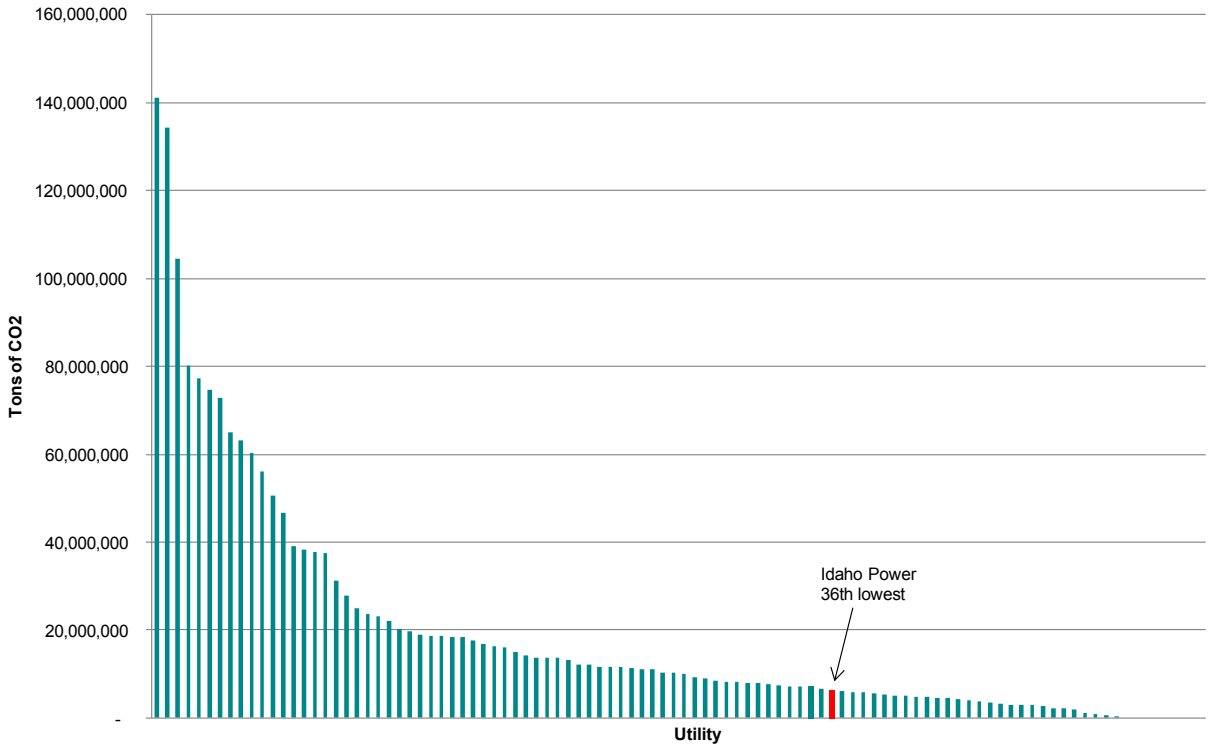


Figure 1.2 CO_2 emissions of the largest 100 utilities

In September 2009, Idaho Power's Board of Directors approved guidelines to reduce Idaho Power's resource portfolio average CO_2 emissions intensity from 2010 through 2013 to 10 to 15 percent below the company's 2005 CO_2 emissions intensity of 1,194 pounds per MWh. Because Idaho Power's CO_2 emissions intensity fluctuates with streamflows and production levels of existing and anticipated renewable resources, the company has adopted an average intensity reduction goal to be achieved over several years.

Currently, generation and emissions from company-owned resources are included in the CO_2 intensity calculation. The company's progress toward achieving this intensity reduction goal and additional information on Idaho Power's CO_2 emissions are reported on the company's website at idahopower.com/AboutUs/Sustainability/CO2Emissions/co2Intensity.cfm.

Information related to Idaho Power's CO_2 emissions is also available through the Carbon Disclosure Project at cdproject.net.

In November 2012, the Board of Directors approved the extension of the company's 2010 to 2013 goal for reducing CO_2 emission intensity. The goal as restated in 2012 is to achieve CO_2 emission intensity 10 to 15 percent below the 2005 CO_2 emission intensity from 2010 to 2015. A second extension of the goal approved by the Board of Directors in May 2015 sets a target CO_2 emission intensity of 15 to 20 percent below the 2005 CO_2 emission intensity for 2016 to 2017.

For the first time in several cycles, the 2015 IRP does not use a carbon adder to estimate the future cost of carbon emissions. The 2015 IRP incorporates the cost and long-term effects of carbon regulation by modeling several scenarios based on the Environmental Protection Agency's (EPA) proposed *Clean Air Act* (CAA) Section 111(d) regulations and the impact it

would have on the company's operations. A more complete discussion of climate change and the regulation of greenhouse gas emissions is available starting on page 64 of the IDACORP, Inc., 2014 Form 10-K at idacorpinc.com/pdfs/10K/10k2014a.pdf.

Proposed Pilot Projects

Solar Photovoltaic to Address Distribution Feeder Voltage Loss

A small-scale proof-of-concept photovoltaic (PV) and battery system pilot project is being considered for feeders with low voltage near the end of the feeder. The purpose of the pilot project is to evaluate its operational performance and its cost-effectiveness. The system will be designed to maintain the feeder voltage within +/- 5 percent of nominal voltage (American National Standards Institute [ANSI] C84.1) and be cost competitive with other options. During 2015 and 2016 the physical and economic feasibility will be examined. If feasible, a pilot system will be constructed and monitored. The results of the work will be reported in the 2017 IRP.

Ice-Based Thermal Energy Storage

Idaho Power proposes a pilot project to investigate the benefits of using ice-based thermal energy storage (TES) to shift peak-hour air conditioning (A/C) load to off-peak periods. The initial phase of the pilot project would involve identifying a customer, designing the system, and putting together a detailed cost estimate. The second phase would be purchasing and installing the equipment, followed by data collection to determine the effectiveness of the concept. The ice-based TES technology is discussed further in Chapter 5.

Community Solar

In the 2009 IRP, Idaho Power proposed a solar PV pilot project. At the time, a downward trend in the cost of solar PV was identified, and that trend has continued over the past few years. In addition, the energy shape of solar generation has been seen as a much better fit with Idaho Power's customer needs when compared to other variable and intermittent renewable resources. For these reasons, the company was interested in gaining experience and data related to solar generation, and a small pilot project was proposed.

In August 2010, the IPUC commented in Order No. 32042 (Case No. IPC-E-09-33) on the proposed solar pilot project, stating:

> Solar power has been identified as a resource that should be pursued by the Company. The recently announced Boise City solar project, we find, will provide Idaho Power that opportunity to assess the merits of such a resource.

Since the issuance of Order No. 32042, a number of unique circumstances have arisen that caused Idaho Power to reassess the appropriate timing and nature of its involvement in solar research and related projects. First, the solar project referenced in the IPUC order did not ultimately provide the assessment opportunity envisioned by the IPUC, as the developers chose not to pursue completion of the project. Further, three months after Order No. 32042 was issued, in November 2010 Idaho Power had 80 megawatts (MW) of *Public Utility Regulatory Policies Act of 1978* (PURPA) wind contracts pending approval at the IPUC, and the company had received another 570 MW of requests for new contracts. It was at that time the company

filed a joint petition to address PURPA policy and pricing issues at the state level, and Case No. GNR-E-10-04 was opened. A short time later, Idaho Power filed an application to modify its net metering service offering, and the IPUC opened Case No. IPC-E-12-27. In this case, the commission considered policy issues related to net metering, specifically in the areas of pricing and equitable cost assignment. Because of the broad scope of policy issues involving renewable generation under consideration by the IPUC in each of these cases, Idaho Power felt it was appropriate to postpone the development of any solar research project or customer-focused program pending the outcome of those cases.

Customer interest in central station and distributed solar generation was the subject of many 2015 IRP discussions, both among IRPAC members and Idaho Power leadership. Late in the 2015 IRP public process, Idaho Power was approached by several interested parties and asked to consider sponsoring a community solar project. The US Department of Energy (DOE) defines "community shared solar" as a solar-electric system that provides power and/or financial benefit to multiple community members.[4] The DOE further states the primary goal of community solar is to increase access to solar energy and to reduce up-front costs for participants. Secondary goals include: 1) improved economies of scale, 2) optimal project siting, 3) increased public understanding of solar energy, and 4) local job generation.

Several models have been used to facilitate community-shared solar projects, including utility-sponsored, special-purpose entity (SPE), and non-profit. Table 1.1 from the DOE compares various community solar models.[5]

Table 1.1 Community solar model comparison

	Utility	SPE	Non-Profit
Owned By	Utility or third party	SPE members	Non-profit
Financed By	Utility, grants, customer subscriptions	Member investments, grants, incentives	Memberships, donor contributions, grants
Hosted By	Utility or third party	Third party	Non-profit
Subscriber Profile	Electric customers of the utility	Community investors	Donors, members
Subscriber Motive	Offset personal electricity use	Return on investment (ROI); offset personal electricity use	ROI; philanthropy
Long-term Strategy of Sponsor	Offer solar options; add solar generation (possibly for a renewable portfolio standard [RPS])	Sell system to host; retain for electricity production	Retain for electricity production for life of the system
Examples	• Sacramento Municipal Utility District—SolarShares Program • Tucson Electric Power—Bright Tucson Program	• University Park Community Solar, LLC • Clean Energy Collective, LLC • Island Community Solar, LLC	• Winthrop Community Solar Project • Solar for Sakai

[4] US Department of Energy. 2012. A guide to community shared solar: Utility, private, and nonprofit project development. http://www.nrel.gov/docs/fy12osti/54570.pdf.

[5] Ibid.

Several possibilities exist for the structure of a solar pilot project. One option Idaho Power is interested in pursuing would be to develop a PV project at a substation near existing load. This concept would not require the addition of new transmission resources and would have economy-of-scale advantages over distributed rooftop installations. The cost of the project could be subsidized by allowing participating customers to voluntarily buy the output from the project to invest in renewable energy.

The interested parties have asked Idaho Power to sponsor a community-based solar project to satisfy the solar pilot project proposed by the company in the 2009 IRP. For an example of this concept, there are several utility-sponsored projects whereby utility customers volunteer by contributing either an up-front or ongoing payment to support a solar project. In exchange, customers receive a payment or credit on their electric bills that is proportional to 1) their contribution and 2) how much electricity the solar project produces. Usually, the utility or an identified third-party owns the solar system itself. The participating customer has no ownership stake in the solar system. Rather, the customer buys rights to the benefits of the energy produced by the system.

It is important to note that Idaho Power's load and resource balance indicates an investment in any new generation, including solar generation, is neither needed nor economic to pursue at this time or during the four-year action plan horizon. However, as regulations governing carbon emissions mature, additional renewable generation may be warranted, and community-shared solar could be a viable option to help satisfy some future carbon intensity targets.

Given the quickly changing regulatory, technological, and economic landscape, the company will explore the risks and opportunities of, and potential designs for, a community-based solar project by continuing to work with interested parties. Because there is no identified resource need in the near-term, a project of this nature would be pursued outside the traditional needs-based regulatory framework and would focus on meeting changing customer preferences with regard to where and how the energy they use is produced.

Portfolio Analysis Summary

A fundamental goal of the IRP process is to identify a selected, or preferred, resource portfolio. The preferred portfolio identifies resource options and timing to allow Idaho Power to continue to reliably serve customer demand, balancing cost, risk, and environmental factors over the 2015 to 2034 planning period. Several key factors create uncertainty regarding the selection of a preferred portfolio in the 2015 IRP. These factors include consideration of North Valmy and Jim Bridger coal unit early retirement, the EPA's proposed CAA Section 111(d) regulation, large contracted amounts of unbuilt PURPA solar projects, and the timing of the B2H transmission line.

North Valmy and Jim Bridger Coal Unit Early Retirement and CAA Section 111(d) Regulation

The 2015 IRP examines the EPA's proposed CAA Section 111(d) regulation and the future of Idaho Power's ownership share of the Jim Bridger and North Valmy coal-fired power plants. With the exception of the Status Quo portfolio, all other portfolios analyzed evaluate alternatives to continued investment in the coal units and/or the impact of reducing generation from

fossil-fueled power plants to comply with uncertain environmental regulations. The optimization of coal unit shutdown alternatives using computer modeling tools will not be possible until the proposed CAA Section 111(d) regulation is finalized sometime in the second half of 2015. It is possible to identify trends in the modeling results that indicate a portfolio with an earlier North Valmy unit shutdown coupled with the completion of the B2H project performs well on a 20-year net-present-value (NPV) basis.

The early retirement of an asset requires accelerating the recovery of the remaining investment in that asset. This increases the cost in the early years in exchange for longer-term savings. This is conceptually similar to repaying a home mortgage early. Over the shortened life of a loan, the total payments will be less, but in the near term the monthly payment will be higher. The same is true when contemplating early retirement of North Valmy or Jim Bridger units. For example, a North Valmy 2019 early shutdown will cost approximately $95 million more between 2015 and 2019 but save approximately $181 million in fixed O&M, capital investment, and finance costs compared to a 2031 to 2034 retirement (in nominal dollars). Unlike the home mortgage example, a coal unit will have little value at the decommissioning date, and it is likely another resource investment will be required.

Uncertainty Related to PURPA Solar

Power supply planning is complicated by the inability of a utility to control the timing, type, and quantity of PURPA resources being added to the Idaho Power generation portfolio. Under PURPA, a utility is obligated to sign energy sales agreements with all qualifying facilities (QF) that request to sell energy to Idaho Power. Changes in PURPA regulations, resource incentives, and technology can and do continuously change the quantity and MWs of projects being proposed or contracted for under PURPA. In addition, even after a PURPA QF agreement is executed with a proposed project, there is still uncertainty whether the project will be built. The result is increased planning uncertainty to the timing and type of company-owned resources needed. Current PURPA regulations also do not consider Idaho Power energy needs or impacts on system reliability, which creates challenging integration issues and is contrary to the company's desire to develop a reliable system as efficiently and cost-effectively as possible.

The IRP load and resource balance includes 461 MW of solar PV from PURPA projects scheduled to be on-line by year-end 2016. The energy and peak-hour capacity of these projects was included in the PURPA forecast at the time the forecast was prepared. The risk of relying on these signed contracts is exemplified by the fact that 141 MW of the 461 MW were recently terminated due to inaction by the PURPA developers. The removal of the 141 MW of solar capacity increases peak-hour capacity deficits by approximately 75 MW. Because the schedule for completing the IRP would not allow the PURPA generation forecast to be updated, the removal of the 141 MW of solar PV generation is addressed in a qualitative manner in the risk analysis section of Chapter 9.

Boardman to Hemingway Transmission

Portfolio analysis for the 2015 IRP indicates portfolios with the B2H transmission line consistently outperform those in which the transmission line is excluded. This result is consistent with analyses of past IRPs, which have shown the B2H project is a valuable supply-side resource that will allow Idaho Power to meet future system needs. Regional growth in renewable energy

resources, such as wind and solar, makes B2H increasingly valuable as it provides increased system flexibility critical to the reliability of interconnected systems with high penetration levels of variable and intermittent resources.

Selection of the Preferred Portfolio

As previously noted, portfolios with early North Valmy unit retirements performed well in the 2015 IRP analysis; analyses show favorable economics for portfolios with the retirement of North Valmy Unit 1 as early as 2019. However, these portfolios carry considerable risk associated with the following factors:

- Uncertainty related to the proposed CAA Section 111(d) regulation, particularly the effect of the final rule on operations at existing coal and natural gas-fired power plants in the proposed interim compliance period beginning in 2020
- Uncertainty related to retirement planning for a jointly owned power plant, specifically the challenges associated with arriving at a retirement date that is feasible to both owners of the plant
- Uncertainty related to PURPA solar and the effect of further project cancellations on capacity additions in the early 2020s
- Uncertainty related to the completion date of the B2H project due to permitting issues and the needs of project partners
- Uncertainty of regulatory acceptance of early coal unit retirement and rate impacts associated with accelerated cost recovery

Given these risks, the preferred portfolio selected is portfolio P6(b), which includes the retirement of the North Valmy plant at year-end 2025 and the completion of the B2H project in 2025. The close linking of these resource actions suggests an earlier completion date of the B2H project could accelerate the decommissioning of the North Valmy plant. Portfolio P6(b) also includes the addition of 60 MW of demand response and 20 MW of ice-based TES in 2030. In 2031, portfolio P6(b) also adds a 300 MW combined-cycle combustion turbine (CCCT). These resource additions late in the planning period address projected needs for resources providing peaking capability and system flexibility. With the expected long-term expansion of variable energy resources, the need for dispatchable resources that provide system flexibility will also increase.

Action Plan

Action plan (2015–2018)

Table 1.2 provides the schedule of action items Idaho Power anticipates over the next four years. Additional details regarding actions related to the Shoshone Falls Hydroelectric Project (Shoshone Falls Project) are presented in chapters 5 and 9 of the IRP.

Table 1.2 Action plan (2015–2018)

Year(s)	Resource	Action	Action Number
2015–2018	B2H	Ongoing permitting, planning studies, and regulatory filings	1
2015–2018	Gateway West	Ongoing permitting, planning studies, and regulatory filings	2
2015–2019	Energy efficiency	Continue the pursuit of cost-effective energy efficiency. The forecast reduction for 2015–2019 programs is 84 average megawatts (aMW) for energy demand and 126 MW for peak demand.	3
2015–2016	N/A	Coordinate with government agencies on implementation planning for CAA Section 111(d).	4
2015	Shoshone Falls	File to amend FERC license regarding 50-MW expansion	5
2015	Jim Bridger Unit 3	Complete installation of selective catalytic reduction (SCR) emission-control technology	6
2015–2016	Shoshone Falls	Study options for a smaller upgrade ranging in size up to approximately 4 MW	7
2016	Jim Bridger Unit 4	Complete installation of SCR emission-control technology	8
2016	North Valmy units 1 and 2	Continue to work with NV Energy to synchronize depreciation dates and determine if a date can be established to cease coal-fired operations	9
2017	Shoshone Falls	Commence construction of smaller upgrade	10
2017	Jim Bridger units 1 and 2	Evaluate the installation of SCR technology for units 1 and 2 at Jim Bridger in the 2017 IRP	11
2019	Shoshone Falls	On-line date for smaller upgrade during first quarter	12

This page left blank intentionally.

2. Political, Regulatory, and Operational Issues

Idaho Energy Plan

In 2007, the Idaho Legislature's Interim Committee on Energy, Environment, and Technology prepared, and the Idaho Legislature approved, a new Idaho Energy Plan for the first time in 25 years. With rapid changes in energy resources and policies, the committee recommended the legislature revisit the Idaho Energy Plan every five years to reflect the interests of Idaho citizens and businesses. In keeping with this recommendation, the plan was reviewed and updated by the Interim Committee and approved by the legislature in 2012. The Idaho Governor's Office of Energy Resources (OER) and the Idaho Strategic Energy Alliance assisted the Interim Committee in updating the energy plan.

The 2012 update finds that Idaho citizens and businesses continue to benefit from stable and secure access to affordable energy, despite the potential economic and political vulnerability caused by Idaho's reliance on energy imports. Idaho currently lacks significant commercial natural gas and oil wells and only generates about half the electricity it uses. Yet the state has abundant hydropower, wind, biomass, and other renewable energy sources.

Ongoing changes in energy generation and consumption provide an opportunity for economic growth within the state. While the Idaho Energy Plan acknowledges the risks attributed to advances in energy generation, transmission, and end-use technologies, it also recognizes the prospective benefits. With this recognition, the 2012 Idaho Energy Plan emphasizes five core objectives:

1. Ensure a secure, reliable, and stable energy system for the citizens and businesses of Idaho.

2. Maintain Idaho's low-cost energy supply and ensure access to affordable energy for all Idahoans.

3. Protect Idaho's public health, safety, and natural environment and conserve Idaho's natural resources.

4. Promote sustainable economic growth, job creation, and rural economic development.

5. Provide the means for Idaho's energy policies and actions to adapt to changing circumstances.

Because the OER was charged with coordinating and cooperating with federal and state agencies on issues concerning the State's energy requirement, Governor C. L. "Butch" Otter asked the OER to coordinate the State of Idaho's response to the EPA Clean Power Plan on behalf of all relevant state agencies.

Idaho Strategic Energy Alliance

Under the umbrella of the OER, the Idaho Strategic Energy Alliance allows various stakeholders to have representation and participate in developing energy plans and strategies for Idaho's

energy future. The Idaho Strategic Energy Alliance is Idaho's primary mechanism for advancing energy production, energy efficiency, and energy business in the State of Idaho.

The purpose of the Idaho Strategic Energy Alliance is to develop a sound energy portfolio for Idaho that includes diverse energy resources and production methods, that provides the highest value to the citizens of Idaho, that ensures quality stewardship of environmental resources, and that functions as an effective, secure, and stable energy system.

Idaho Power representatives serve on both the Idaho Strategic Energy Alliance board of directors and a number of the volunteer task forces that work in the following areas:

- Energy efficiency and conservation
- Wind
- Geothermal
- Hydropower
- Carbon issues
- Baseload resources
- Economic/financial development
- Forestry
- Biogas
- Biofuel
- Solar
- Transmission
- Communication and outreach

FERC Relicensing

Like other utilities that operate non-federal hydroelectric projects on qualified waterways, Idaho Power obtains licenses from FERC for its hydroelectric projects. The licenses last for 30 to 50 years, depending on the size, complexity, and cost of the project.

Idaho Power filed a final license application (FLA) for the Swan Falls Project with FERC in June 2008, and the new license for the Swan Falls Project was issued by FERC on September 8, 2012, for a 30-year term expiring September 1, 2042.

Idaho Power's remaining and most significant ongoing relicensing effort is the Hells Canyon Complex (HCC). The HCC provides approximately two-thirds of Idaho Power's hydroelectric generating capacity and 34 percent of the company's total generating capacity. The current license for the HCC expired in July 2005. Until the new, multi-year license is issued, Idaho Power continues to operate the project under an annual license issued by FERC.

The HCC license application was filed in July 2003 and accepted by FERC for filing in December 2003. FERC is now processing the application consistent with the requirements of the *Federal Power Act of 1920*, as amended (FPA); the *National Environmental Policy Act of 1969*, as amended (NEPA); the *Endangered Species Act of 1973* (ESA); and other applicable federal laws.

Administrative work on relicensing the HCC is expected to continue until a new license is issued. After a new license is issued, further costs will be incurred to comply with the terms of the new license. Because the new license for the HCC has not been issued, and discussions on the protection, mitigation, and enhancement (PM&E) packages are still being conducted, it is not possible to estimate the final total cost.

Relicensing activities include the following:

1. Coordinating the relicensing process
2. Consulting with regulatory agencies, tribes, and interested parties
3. Preparing studies and gathering environmental data on fish, wildlife, recreation, and archaeological sites
4. Preparing studies and gathering engineering data on historical flow patterns, reservoir operation and load shaping, forebay and river sedimentation, and reservoir contours and volumes
5. Studying and analyzing data
6. Preparing all necessary reports, exhibits, and filings responding to requests for additional information from FERC
7. Consulting on legal matters

Failure to relicense any of the existing hydroelectric projects at a reasonable cost will create upward pressure on the 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 PM&E measures imposed as a condition of relicensing. 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 in the 2015 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 generation resources.

Idaho Water Issues

Power generation at Idaho Power's hydroelectric projects on the Snake River and its tributaries is dependent on the state water rights held by the company for these projects. The long-term sustainability of the Snake River Basin streamflows, including tributary spring flows and the regional aquifer system, is crucial for Idaho Power to maintain generation from these projects, and the company is dedicated to the vigorous defense of its water rights. None of the pending water-management issues is expected to affect Idaho Power's hydroelectric generation in the near term, but the company cannot predict the ultimate outcome of the legal and administrative

water-right proceedings. Idaho Power's ongoing participation in water-right issues is intended to guarantee sufficient water is available for use at the company's hydroelectric projects on the Snake River.

Snake River below Bliss.

Idaho Power, along with other Snake River Basin water-right holders, was engaged in the Snake River Basin Adjudication (SRBA), a general streamflow adjudication process started in 1987 to define the nature and extent of water rights in the Snake River Basin. The initiation of the SRBA resulted from the Swan Falls Agreement entered into by Idaho Power and the governor and attorney general of Idaho in October 1984. Idaho Power filed claims for all of its hydroelectric water rights in the SRBA. As a result of the SRBA, the company's water rights were adjudicated, resulting in the issuance of partial water-right decrees. The Final Unified Decree for the SRBA was signed on August 25, 2014.

In 1984, the Swan Falls Agreement resolved a struggle between the State of Idaho and Idaho Power over the company's water rights at the Swan Falls Project. The agreement stated Idaho Power's water rights at its hydroelectric facilities between Milner Dam and Swan Falls entitled the company to a minimum flow at Swan Falls of 3,900 cubic feet per second (cfs) during the irrigation season and 5,600 cfs during the non-irrigation season.

The Swan Falls Agreement placed the portion of the company's water rights beyond the minimum flows in a trust established by the Idaho Legislature for the benefit of Idaho Power and the citizens of the state. Legislation establishing the trust granted the state authority to allocate trust water to future beneficial uses in accordance with state law. Idaho Power retained the right to use water in excess of the minimum flows at its facilities for hydroelectric generation until it was reallocated to other uses.

Idaho Power filed suit in the SRBA in 2007, as a result of disputes about the meaning and application of the Swan Falls Agreement. The company asked the court to resolve issues associated with Idaho Power's water rights and the application and effect of the trust provisions of the Swan Falls Agreement. In addition, Idaho Power asked the court to determine whether the agreement subordinated the company's hydroelectric water rights to aquifer recharge.

A settlement signed in 2009 reaffirmed the Swan Falls Agreement and resolved the litigation by clarifying the water rights held in trust by the state are subject to subordination to future upstream beneficial uses, including aquifer recharge. The settlement also committed the state and Idaho Power to further discussions on important water-management issues concerning the Swan Falls Agreement and the management of water in the Snake River Basin. Idaho Power and the State of Idaho are actively involved in those discussions. The settlement also recognizes

water-management measures that enhance aquifer levels, springs, and river flows—such as aquifer-recharge projects—that benefit both agricultural development and hydroelectric generation. Both parties are working with water users and other stakeholders in the development of water-management measures through the implementation of the Eastern Snake River Plain Aquifer (ESPA) *Comprehensive Aquifer Management Plan* (CAMP) as approved by the Idaho Water Resource Board (IWRB) and the 2009 Swan Falls Reaffirmation Agreement.

Given the high degree of interconnection between the ESPA and Snake River, Idaho Power recognizes the importance of aquifer-management planning in promoting the long-term sustainability of the Snake River. The company continues to emphasis implementation of the ESPA CAMP to improve aquifer levels and tributary spring flows to the Snake River. While some of the Phase I recommendations outlined in Table 2.1 were slow to develop due to limited initial funding, House Bill 547 signed into law by Governor Otter in 2014 provides $5 million annually to the IWRB for aquifer stabilization projects, with the ESPA having first priority.

While there have been two practices—recharge and weather modification—that have received funding and have met or exceeded targets, declining aquifer levels and spring discharge persist.

During the winter of 2014 to 2015, weather and canal maintenance conditions allowed for an extended wintertime recharge season from October 27, 2014, to March 24, 2015, resulting in a volume recharged of 72,325 acre-feet. This volume significantly exceeded the combined recharge of the two previous seasons and exceeded the average annual recharge of the previous five seasons by 4,500 acre-feet.

Idaho Power initiated and pursued a successful weather modification program in the Snake River Basin. The company partnered with an existing program in the upper Snake River Basin and, through the cooperative effort, has greatly expanded the existing weather modification operational program, along with forecasting and meteorological data support. The company has an established, long-term plan to continue the expansion of this program. In 2014, Idaho Power expanded its cloud-seeding program to the Boise and Wood River basins, in collaboration with basin water users and the IWRB. Wood River cloud seeding, along with the upper Snake activities, will benefit the ESPA CAMP implementation through additional water supply.

Table 2.1 Phase I measures included in the ESPA CAMP

Measure	Target (acre-feet)	Estimated to Date (acre-feet)
Groundwater to surface-water conversions	100,000	30,300
Managed aquifer recharge	100,000	78,000*
Demand reduction	–	–
Surface-water conservation	50,000	26,000
Crop-mix modification	5,000	0
Rotating fallowing, dry-year lease, conservation reserve enhancement program (CREP)	40,000	34,000
Weather modification	50,000	250,000

*Average annual recharge from 2009 to 2014.

For the 2015 IRP, Idaho Power forecasted flows similar to those in the 2013 IRP, with declines in reach gains extending through the end of the IRP planning period. Based on modeling under the 90-percent exceedance forecast, declining flows at Swan Falls drop to 4,030 cfs, which is slightly higher than the Swan Falls minimum of 3,900 cfs. Figure 2.1 provides the yearly April through July inflow to Brownlee Reservoir as forecasted for the 2015 IRP.

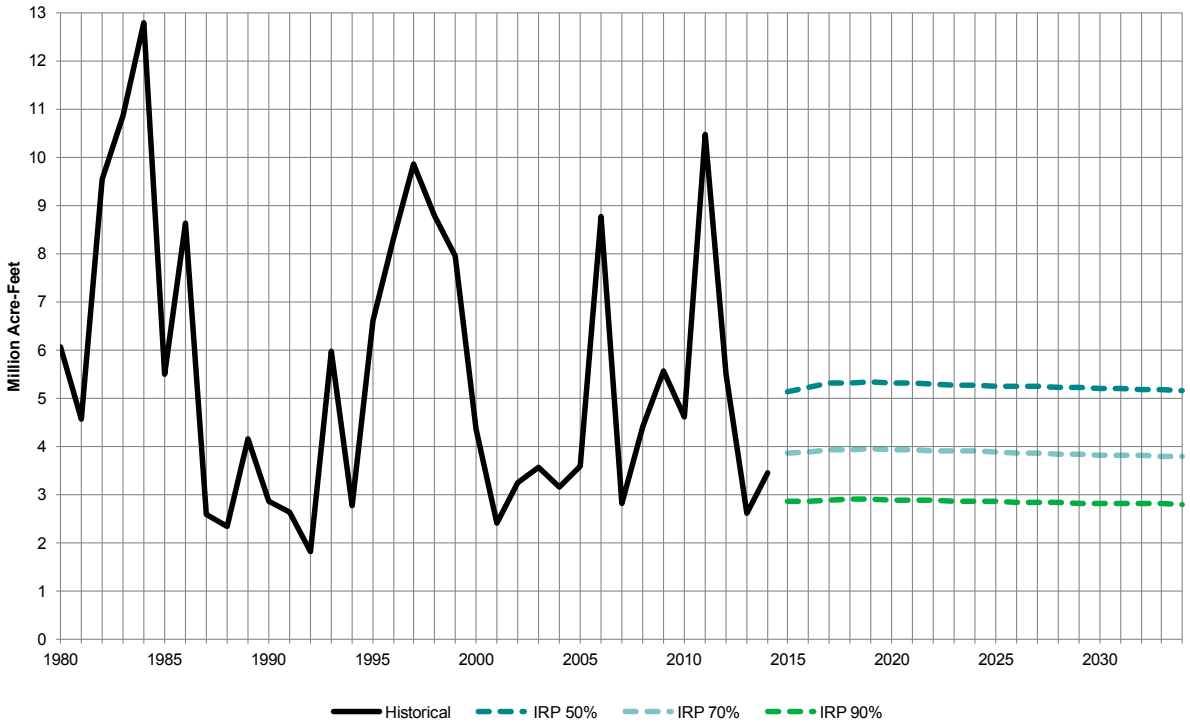


Figure 2.1 Brownlee historical and 2015 to 2034 forecasted April to July inflow

Renewable Integration Study

Idaho Power has completed two wind integration studies and one solar integration study since the mid-2000s. These studies increased the company's understanding of the impacts and costs associated with integrating variable and intermittent resources without compromising reliability. The variable and uncertain production from wind and solar resources requires Idaho Power to provide additional balancing reserves from existing dispatchable generating resources, which results in lost opportunity costs and corresponding increases in power supply expenses.

Idaho Power completed the most recent wind integration study in 2013, which was the basis for a tariff schedule of wind integration costs proposed to the IPUC by Idaho Power. The IPUC approved the proposal as Schedule 87 in Order No. 33150 in October 2014.

The first Idaho Power solar integration study was completed in 2014, and the subsequent revision to Schedule 87 was approved by the IPUC in Order No. 33227 in February 2015 as part of a settlement stipulation between Idaho Power and intervening parties. The solar integration

settlement stipulation includes provisions requiring Idaho Power to initiate a second solar integration study by January 2015 and to complete the second study within 12 months. Idaho Power has formed a Technical Review Committee of renewable energy experts for the second solar integration study, which is in progress but will not be finished prior to the completion of the 2015 IRP.

The results of the integration studies show periods of low customer demand to be the most difficult to cost-effectively integrate variable resources. During low demand periods, other existing resources are often already running at minimum levels or may already be shut off. Under these conditions, curtailment of the variable resources may be necessary to keep generation balanced with customer load. The integration studies also demonstrate the frequency of curtailment events are expected to increase as additional variable resources are added to the system.

For the IRP, integration costs for existing wind and solar resources are common to all the portfolios analyzed and are not included in the portfolio cost accounting. However, portfolios with new wind or solar resources do include costs consistent with Schedule 87 for the new resources. A copy of Schedule 87 is provided in *Appendix C—Technical Appendix*.

Northwest Power Pool Energy Imbalance Market

Since 2012, the Northwest Power Pool (NWPP) has evaluated energy imbalance markets (EIM), sometimes referred to as a security-constrained economic dispatch (SCED). A second phase of the effort was focused on refining the design elements of a SCED to suit the unique issues present in the NWPP. A third phase just completed developed a number of operational tools to facilitate a more robust and reliable system operation. The NWPP is now moving into a fourth phase to continue to refine design elements of an SCED to develop additional low-cost/high-value tools to enhance system operation. Many institutional issues remain before an SCED can be implemented in the Pacific Northwest.

For Idaho Power, there are several principle benefits to an EIM:

1. The market would provide greater access to balancing energy to accommodate intermittent generation variations within Idaho Power's balancing area.

2. There would be a slight improvement in real-time dispatch costs.

3. The market would provide better real-time pricing for power imbalances that occur in real-time for wholesale power customers.

Idaho Power supports, and will continue to participate in, the NWPP discussions; however, participation by a majority of the NWPP members will be required to realize the benefits of an EIM.

Renewable Energy Certificates

RECs, also known as green tags, represent the green or renewable attributes of energy produced by certified renewable resources. A REC represents the renewable attributes associated with the production of 1 MWh of electricity generated by a qualified renewable energy resource, such as a wind turbine, geothermal plant, or solar facility. The purchase of a REC buys the renewable attributes, or "greenness," of that energy.

A renewable or green energy provider (e.g., a wind farm) is credited with one REC for every 1,000 kilowatt-hours (kWh), or 1 MWh, of electricity produced. RECs and the electricity produced by a certified renewable resource can either be sold together (bundled), sold separately (unbundled), or be retired to comply with a state- or federal-level RPS. An RPS is a policy requiring that a minimum amount (usually a percentage) of the electricity each utility delivers to customers comes from renewable energy.

A certifying tracking system gives each REC a unique identification number to facilitate tracking purchases, sales, and retirements. The electricity produced by the renewable resource is fed into the electrical grid, and the associated REC can then be used (retired), held (banked), or traded (sold).

REC prices depend on many factors, including the following:

- The location of the facility producing the RECs
- REC supply/demand
- Whether the REC is certified for RPS compliance
- The generation type (e.g., wind, solar, geothermal)
- Whether the RECs are bundled with energy or unbundled

When Idaho Power sells RECs, the proceeds are returned to Idaho Power customers through the power cost adjustment (PCA) as directed by the IPUC in Order No. 32002 and by the OPUC in Order No. 11-086. Because the RECs were sold, Idaho Power cannot claim the renewable attributes associated with those RECs. The new REC owner has purchased the rights to claim the renewable attributes of that energy.

Idaho Power customers who choose to purchase renewable energy can do so under Idaho Power's Green Power Program. Under this program, every dollar contributed by a customer brings about the delivery of 118 kWh of renewable energy to the region's power grid, providing the contributing customer associated claims for the renewable energy. The entire amount designated is used to purchase green power from renewable projects in the Northwest and to support Solar 4R Schools. On behalf of program participants, Idaho Power obtains and retires RECs. For the 2014 Green Power Program, Idaho Power purchased and subsequently retired 19,318 RECs on behalf of Green Power participants.

Renewable Portfolio Standard

Idaho Power anticipates that existing hydroelectric facilities will not be included in RPS calculations. However, hydroelectric upgrades on existing facilities, such as the Shoshone Falls upgrade, will likely be included in RPS calculations.

Under the Oregon RPS, Idaho Power is classified as a smaller utility because the company's Oregon customers represent less than 3 percent of Oregon's total retail electric sales. As a smaller utility, Idaho Power will have to meet a 5- or 10-percent RPS requirement beginning in 2025.

While the State of Idaho does not have an RPS, a federal renewable energy standard (RES) is a possibility. Idaho Power believes it is prudent to continue acquiring RECs associated with renewable resources to position the company's resource and REC portfolio to minimize the potential effect on customers if a federal RES is implemented.

REC Management Plan

In December 2009, Idaho Power filed a REC management plan with the IPUC that detailed the company's plans to continue acquiring long-term rights to RECs in anticipation of a federal RES, but to sell RECs in the near term and return to customers their 95-percent share of the proceeds as defined under the PCA mechanism. In June 2010, the IPUC accepted Idaho Power's REC management plan in Order No. 32002 (Case No. IPC-E-08-24).

Federal Energy Legislation CAA Section 111(d)

Idaho Power is subject to a broad range of federal, state, regional, and local environmental laws and regulations. Current and pending environmental legislation relates to climate change, greenhouse gas emissions and air quality, mercury (Hg) and other emissions, hazardous wastes, polychlorinated biphenyls, and endangered and threatened species. The legislation includes the CAA, the *Clean Water Act of 1972* (CWA); the *Resource Conservation and Recovery Act of 1976* (RCRA); the *Toxic Substances Control Act of 1976* (TSCA); the *Comprehensive Environmental Response, Compensation and Liability Act of 1980* (CERCLA); and the ESA.

The utility industry will continue to respond to changes in environmental legislation associated with utility operations, including emissions regulations associated with the operation of coal and natural gas-fired generating facilities.

On June 2, 2014, the EPA, under President Obama's Climate Action Plan, released its long-anticipated proposal to regulate CO_2 emissions from existing power plants under CAA Section 111(d). EPA's proposed Clean Power Plan includes ambitious, mandatory CO_2 reduction targets for each state designed to achieve nationwide 30-percent CO_2 emission reductions over 2005 levels by 2030. The EPA has proposed a novel approach, extending regulations beyond the stationary source itself, which is where the EPA has traditionally confined its authority. Each state's rate-based goal, namely pounds of CO_2 per MWh was calculated using four building blocks:

1. Building Block 1—Improve efficiency in existing coal-fired power plants.

2. Building Block 2—Re-dispatch generation from existing coal-fired power plants to natural gas combined-cycle plants.

3. Building Block 3—Increase generation from non-CO_2-emitting resources.

4. Building Block 4—Increase end-use energy efficiency programs.

A combination of the four building blocks was used to calculate an interim goal (average of years 2020–2029) and a final 2030 goal. Each state would then implement the goals through a state plan, which will need to be approved by the EPA. Each rate-based goal would be legally binding on each state.

With new comprehensive federal energy legislation, a utility's resource portfolio will continue to evolve in response to its obligation to serve, market conditions, perceived risks, and regulatory policy changes. Because the EPA's proposed regulation will not be finalized until sometime after the completion of the 2015 IRP, the IRP analysis examines several compliance sensitivities that represent possible outcomes of the final regulation. Additional information on these sensitivities is presented in Chapter 9 and in *Appendix C—Technical Appendix*.

3. Idaho Power Today

Customer Load and Growth

In 1990, Idaho Power served approximately 290,000 general business customers. Today, Idaho Power serves more than 515,000 general business customers in Idaho and Oregon. Firm peak-hour load has increased from 2,052 MW in 1990 to over 3,400 MW. On July 2, 2013, the peak-hour load reached 3,407 MW—the system peak-hour record.

Construction in downtown Boise.

Average firm load increased from 1,200 aMW in 1990 to 1,739 aMW in 2014 (load calculations exclude the load from the former special-contract customer Astaris, or FMC). Additional details of Idaho Power's historical load and customer data are shown in Figure 3.1 and Table 3.1.

Since 1990, Idaho Power's total nameplate generation has increased from 2,635 MW to 3,594 MW. The 959-MW increase in capacity represents enough generation to serve nearly 175,000 customers at peak times. Table 3.1 shows Idaho Power's changes in reported nameplate capacity since 1990.

Idaho Power's newest resource addition is the 318-MW Langley Gulch CCCT. This highly efficient, natural gas-fired power plant is located in the western Treasure Valley in Payette County, Idaho. Construction of the plant began in August 2010, and the plant became commercially available in June 2012.

The data in Table 3.1 suggests each new customer adds approximately 5.5 kilowatts (kW) to the peak-hour load and about 2.5 average kilowatts (akW) to the average load. In actuality, residential, commercial, and irrigation customers generally contribute more to the peak-hour load, whereas industrial customers contribute more to the average load; industrial customers generally have a more consistent load shape.

Since 1990, Idaho Power has added about 225,000 new customers. The simple peak-hour and average-energy calculations mentioned earlier suggest the additional 225,000 customers require 1,237 MW of additional peak-hour capacity and about 560 aMW of energy.

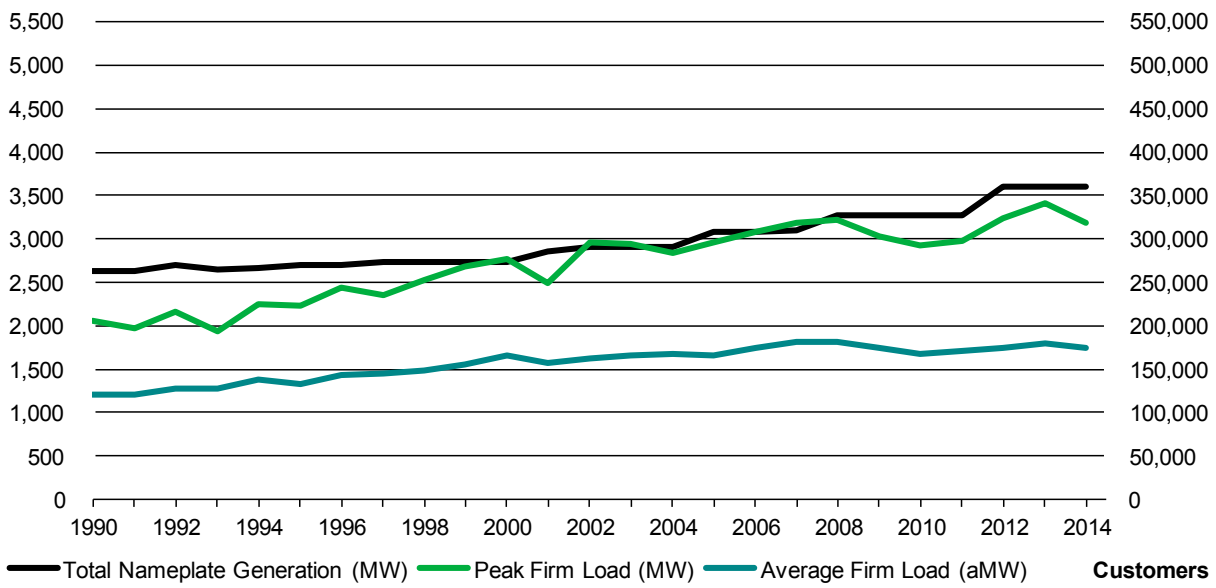


Figure 3.1 Historical capacity, load, and customer data

Table 3.1 Historical capacity, load, and customer data

Year	Total Nameplate Generation (MW)	Peak Firm Load (MW)	Average Firm Load (aMW)	Customers[1]
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
2006	3,085	3,084	1,745	470,950
2007	3,093	3,193	1,808	480,523
2008	3,276	3,214	1,815	486,048
2009	3,276	3,031	1,742	488,813
2010	3,276	2,930	1,679	491,368
2011	3,276	2,973	1,711	495,122
2012	3,594	3,245	1,745	500,731
2013	3,594	3,407	1,801	508,051
2014	3,594	3,184	1,739	515,262

[1] Year-end residential, commercial, and industrial count plus the maximum number of active irrigation customers

Idaho Power anticipates adding approximately 9,800 customers each year throughout the 20-year planning period. The expected-case load forecast predicts summer peak-hour load requirements will grow at about 62 MW per year, and the average-energy requirement is forecast to grow at 24 aMW per year. More detailed customer and load forecast information is presented in Chapter 7 and in *Appendix A—Sales and Load Forecast*.

The simple peak-hour load-growth calculation indicates Idaho Power would need to add peaking capacity equivalent to the 318-MW Langley Gulch CCCT plant every five years throughout the entire planning period. The peak calculation does not include the expected effects of demand response programs, and Idaho Power intends to continue working with customers and applying demand response programs during times of peak energy consumption. The plan to meet the requirements of Idaho Power's load growth is discussed in Chapter 10.

The generation costs per kW included in Chapter 7 provide some perspective on customer growth. Load research data indicates the average residential customer requires about 1.5 kW of baseload generation and 5 to 5.5 kW of peak-hour generation. Baseload generation capital costs are about $1,145 per kW for a natural gas-fired CCCT, such as Idaho Power's Langley Gulch Power Plant, and peak-hour generation capital costs are about $800 per kW for a natural gas-fired simple-cycle combustion turbine (SCCT), such as the Danskin and Bennett Mountain projects. These capital-cost estimates are in 2015 dollars and do not include fuel or any other O&M expenses.

Based on the capital-cost estimates, each new residential customer requires over $1,700 of capital investment for 1.5 kW of baseload generation, plus an additional $4,400 for 5 to 6 kW of peak-hour capacity, leading to a total generation capital cost of over $6,100. Other capital expenditures for transmission, distribution, customer systems, and other administrative costs are not included in the $6,100 capital generation requirement. A residential customer growth rate of 9,800 new customers per year translates into almost $60 million of new generation plant capital each year to serve the baseload and peak energy requirements of new residential customers.

2014 Energy Sources

Idaho Power's system receives energy from a variety of fuel types and integrates energy from more than 100 PURPA projects and three power purchase agreements (PPA) in addition to company-owned generation. Figure 3.2 shows the nameplate capacity of resources delivering to Idaho Power's system from company-owned resources, PURPA contracts, and long-term PPAs.

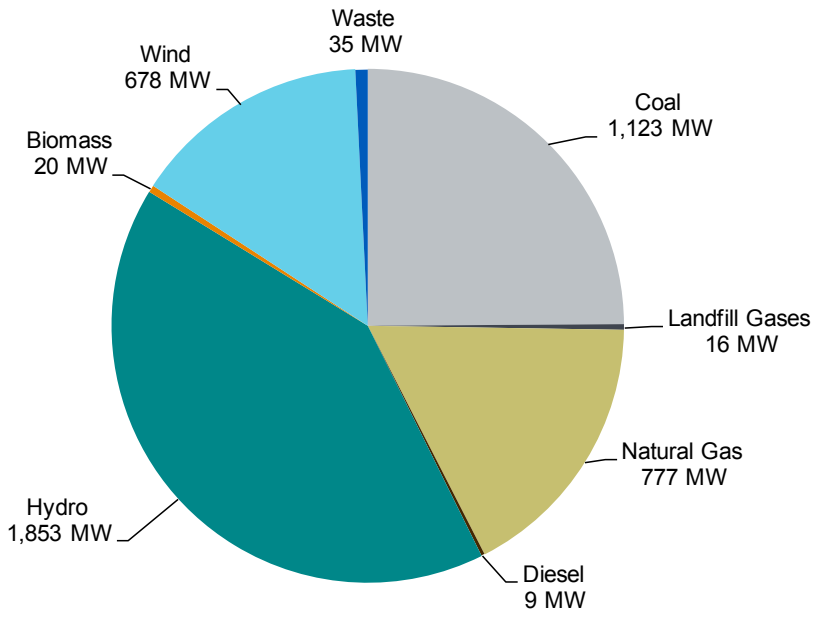


Figure 3.2 2014 Idaho Power system nameplate by fuel type (MW) (owned resources plus purchased power)

Idaho Power's electricity sources for 2014 are shown in Figure 3.3. Idaho Power generated 77 percent of the total energy requirement. In above-average water years, Idaho Power's low-cost hydroelectric plants are typically the company's largest source of electricity. Purchased power provides the remaining 23 percent of the energy requirement and includes power purchased from PURPA projects, market purchases, and PPAs, the need for which has been identified in past IRPs.

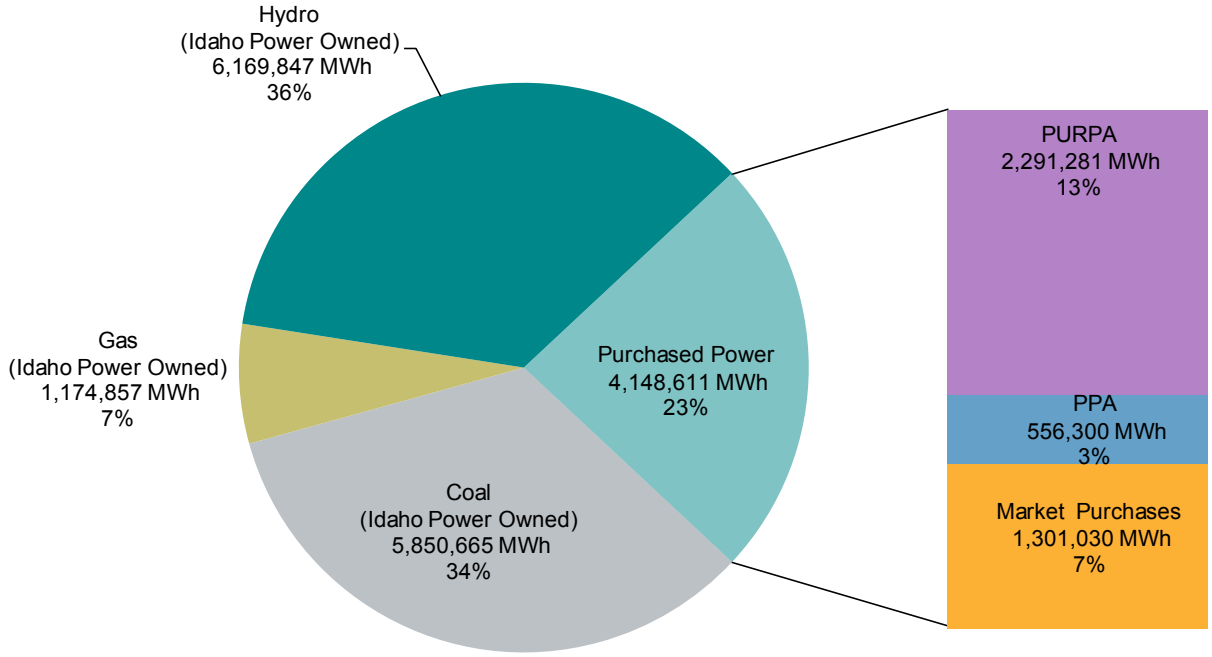


Figure 3.3 2014 energy by source

In 2014, Idaho Power purchased 4,148,611 MWh of electricity through PURPA contracts, market purchases, and long-term PPAs. Figure 3.4 provides a percentage breakdown by fuel type for the PPA and PURPA purchases. Market purchases are shown in total but not identified by fuel type since the original resource is not known. Idaho Power receives RECs from the Elkhorn Valley Wind Project, the Raft River Geothermal Project, and the Neal Hot Springs Geothermal Project. However, as noted in Chapter 2, Idaho Power is required to sell these RECs, and none of the renewable generation is represented as being delivered to Idaho Power retail customers in 2014.

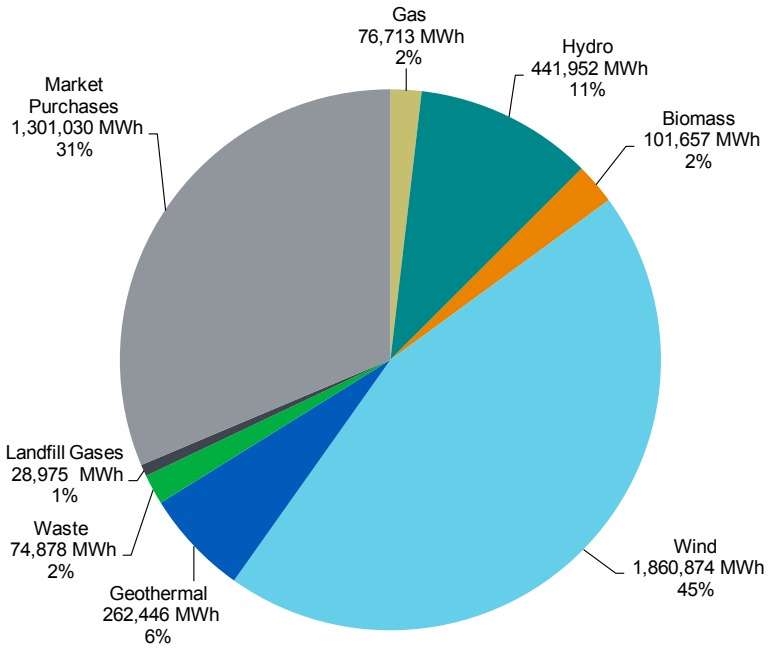


Figure 3.4 2014 power purchases by fuel type

Existing Supply-Side Resources

To identify the need and timing of future resources, Idaho Power prepares a load and resource balance that accounts for forecast load growth and generation from all of the company's existing resources and planned purchases. The load and resource balance worksheets showing Idaho Power's existing and committed resources for average-energy and peak-hour load are presented in *Appendix C—Technical Appendix*. Table 3.2 shows all of Idaho Power's existing resources, nameplate capacities, and general locations.

Table 3.2 Existing resources

Resource	Type	Generator Nameplate Capacity (MW)	Location
American Falls	Hydroelectric	92.3	Upper Snake
Bliss	Hydroelectric	75.0	Mid-Snake
Brownlee	Hydroelectric	585.4	Hells Canyon
C. J. Strike	Hydroelectric	82.8	Mid-Snake
Cascade	Hydroelectric	12.4	North Fork Payette
Clear Lake	Hydroelectric	2.5	South Central Idaho
Hells Canyon	Hydroelectric	391.5	Hells Canyon
Lower Malad	Hydroelectric	13.5	South Central Idaho
Lower Salmon	Hydroelectric	60.0	Mid-Snake
Milner	Hydroelectric	59.4	Upper Snake
Oxbow	Hydroelectric	190.0	Hells Canyon
Shoshone Falls	Hydroelectric	12.5	Upper Snake
Swan Falls	Hydroelectric	27.2	Mid-Snake
Thousand Springs	Hydroelectric	8.8	South Central Idaho
Twin Falls	Hydroelectric	52.9	Mid-Snake
Upper Malad	Hydroelectric	8.3	South Central Idaho
Upper Salmon A	Hydroelectric	18.0	Mid-Snake
Upper Salmon B	Hydroelectric	16.5	Mid-Snake
Boardman	Coal	64.2	North Central Oregon
Jim Bridger	Coal	770.5	Southwest Wyoming
North Valmy	Coal	283.5	North Central Nevada
Langley Gulch	Natural Gas—CCCT	318.5	Southwest Idaho
Bennett Mountain	Natural Gas—SCCT	172.8	Southwest Idaho
Danskin	Natural Gas—SCCT	270.9	Southwest Idaho
Salmon Diesel	Diesel	5.0	Eastern Idaho
Total existing nameplate capacity		**3,594.4**	

The following sections describe Idaho Power's existing supply-side generation resources and long-term PPAs.

Hydroelectric Facilities

Idaho Power operates 17 hydroelectric projects on the Snake River and its tributaries. Together, these hydroelectric facilities provide a total nameplate capacity of 1,709 MW and an annual generation equal to approximately 970 aMW, or 8.5 million MWh under median water conditions.

Hells Canyon Complex

The backbone of Idaho Power's hydroelectric system is the HCC in the Hells Canyon reach of the Snake River. The HCC consists of Brownlee, Oxbow, and Hells Canyon dams and the associated generation facilities. In a normal water year, the three plants provide approximately 70 percent of Idaho Power's annual hydroelectric generation and approximately 30 percent of the total energy generated. Water storage in Brownlee Reservoir also enables the HCC projects to provide the major portion of Idaho Power's peaking and load-following capability.

Idaho Power operates the HCC to comply with the existing annual 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 Program, voluntarily adopted by Idaho Power in 1991 to protect the spawning and incubation of fall Chinook salmon (*Oncorhynchus tshawytscha*) below Hells Canyon Dam. The fall Chinook salmon is currently listed as threatened under the ESA.

Brownlee Reservoir is the main HCC reservoir and Idaho Power's only reservoir with significant active storage. Brownlee Reservoir has 101 vertical feet of active storage capacity, which equals approximately 1 million acre-feet of water. Both Oxbow and Hells Canyon reservoirs have significantly smaller active storage capacities—approximately 0.5 percent and 1 percent of Brownlee Reservoir's volume, respectively.

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 for system flood control, recreation, and the benefit of fish and wildlife resources.

Brownlee Dam is one of several Pacific Northwest dams coordinated to provide springtime flood control on the lower Columbia River. Idaho Power operates the reservoir in accordance with flood-control directions received from the US Army Corps of Engineers (USACE) as outlined in Article 42 of the existing FERC license.

After 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 US Bureau of Reclamation (USBR) releases water from USBR storage reservoirs in the Snake River basin above Brownlee Reservoir to augment flows in the lower Snake River to help anadromous fish migrate past the Federal Columbia River Power System (FCRPS) projects. The releases are part of the flow augmentation implemented by the 2008 FCRPS biological opinion. Much of the flow augmentation water travels through Idaho Power's middle Snake River (mid-Snake) projects, with all of the flow augmentation eventually passing through the HCC before reaching the FCRPS projects.

Brownlee Reservoir's releases are managed to maintain constant flows below Hells Canyon Dam in the fall as a result of the Fall Chinook Program adopted by Idaho Power in 1991. The constant flow is set at a level to protect fall Chinook spawning nests, or redds. During the fall Chinook

operations, Idaho Power attempts to refill Brownlee Reservoir by the first week of December to meet wintertime peak-hour loads. The fall Chinook plan spawning flows establish the minimum flow below Hells Canyon Dam throughout the winter until the fall Chinook fry emerge in the spring.

Upper Snake and Mid-Snake Projects

Idaho Power's hydroelectric facilities upstream from the HCC include the Cascade, Swan Falls, C. J. Strike, Bliss, Lower Salmon, Upper Salmon, Upper and Lower Malad, Thousand Springs, Clear Lake, Shoshone Falls, Twin Falls, Milner, and American Falls projects. Although the upstream projects typically follow run-of-river (ROR) operations, a small amount of peaking and load-following capability exists at the Lower Salmon, Bliss, and C. J. Strike projects. These three projects are operated within the FERC license requirements to coincide with daily system peak demand when load-following capacity is available.

Idaho Power completed a study to identify the effects of load-following operations at the Lower Salmon and Bliss power plants on the Bliss Rapids snail (*Taylorconcha serpenticola*), a threatened species under the ESA. The study was part of a 2004 settlement agreement with the US Fish and Wildlife Service (FWS) to relicense the Upper Salmon, Lower Salmon, Bliss, and C. J. Strike hydroelectric projects. During the study, Idaho Power annually alternated operating the Bliss and Lower Salmon facilities under ROR and load-following operations. Study results indicated that while load-following operations had the potential to harm individual snails, the operations were not a threat to the viability or long-term persistence of the species.

A *Bliss Rapids Snail Protection Plan* developed in consultation with the FWS was completed in March 2010. The plan identifies appropriate protection measures to be implemented by Idaho Power, including monitoring snail populations in the Snake River and associated springs. By implementing the protection and monitoring measures, the company has been able to operate the Lower Salmon and Bliss projects in load-following mode while protecting the stability and viability of the Bliss Rapids snail. Idaho Power has received a license amendment from FERC for both projects that allows load-following operations to resume.

Water Lease Agreements

Idaho Power views the rental of water for delivery through its hydroelectric system as a potentially cost-effective power-supply alternative. Water leases that allow the company to request delivery when the water is needed are especially beneficial. Acquiring water through the water bank also helps the company improve water-quality and temperature conditions in the Snake River as part of ongoing relicensing efforts associated with the HCC.

The company signed a rental agreement in 2014 with Water District 63 in the Boise River basin to rent 8,000 acre-feet of storage water released in January 2015. In August 2009, Idaho Power also entered into a five-year (2009–2013) water-rental agreement with the Shoshone–Bannock Tribal Water Supply Bank for 45,716 acre-feet of American Falls storage water. In 2011, the company extended the Shoshone–Bannock rental agreement for two additional years, 2014 and 2015.

Under the terms of this agreement, the company can schedule the release of the water to maximize the value of the generation from the entire system of mainstem Snake River

hydroelectric projects. The company typically scheduled delivery of the water between July and October each year during the term of the agreement. The Shoshone–Bannock agreement was executed in part to offset the effect of drought and changing water-use patterns in southern Idaho and to provide additional generation in summer months when customer demand is high. The company is reviewing the potential to renegotiate the Shoshone–Bannock agreement for future years. Idaho Power intends to continue to pursue water-rental opportunities as part of its regular operations.

Cloud Seeding

In 2003, Idaho Power implemented a cloud-seeding program to increase snowpack in the south and middle forks of the Payette River watershed. In 2008, Idaho Power began expanding its program by enhancing an existing program operated by a coalition of counties and other stakeholders in the upper Snake River Basin above Milner Dam. Idaho Power has continued to work with the stakeholders in the upper Snake River to expand the program and has recently collaborated with irrigators in the Boise and Wood River Basins to expand the target to include those watersheds.

Idaho Power seeds clouds by introducing silver iodide (AgI) into winter storms. Cloud seeding increases precipitation from passing winter-storm systems. If a storm has the right combination of abundant supercooled liquid water vapor and appropriate temperatures and winds, conditions are optimal for cloud seeding to increase precipitation.

Remote cloud-seeding generator.

Idaho Power uses two methods to seed clouds:

1. Remotely operated ground generators at high elevations
2. Modified aircraft burning flares containing AgI

Benefits of either method vary by storm, and the combination of both methods provides the most flexibility to successfully place AgI into passing storms. Minute water particles within the clouds freeze on contact with the AgI particles and eventually grow and fall to the ground as snow.

AgI is a very efficient ice nuclei that allows it to be used in minute quantities. It has been used as a seeding agent in numerous western states for decades without any known harmful effects (weathermodification.org/images/AGI_toxicity.pdf). Analyses conducted by Idaho Power since 2003 indicate the annual snowpack in the Payette River Basin increased between 1 and 28 percent annually with an annual average of 14 percent. Idaho Power estimates cloud seeding currently provides an additional 250,000 acre-feet from the upper Snake River and 269,000 acre-feet from the Payette River. At program build-out, Idaho Power estimates that additional runoff from the Payette, Boise, Wood, and Upper Snake projects will total approximately 1,000,000 acre-feet. Studies conducted by the Desert Research Institute from 2003 to 2005 support the effectiveness of Idaho Power's program.

For the 2014 to 2015 winter season, the program included 23 remote-controlled, ground-based generators and 2 aircraft for operations in the west central mountains (Payette, Boise, and Wood River basins. The Upper Snake River Basin program included 21 remote-controlled, ground-based generators operated by Idaho Power and 25 manual, ground-based generators operated by the coalition of stakeholders in the Upper Snake. Idaho Power provides meteorological data and weather forecasting to guide the coalition's operations.

Coal Facilities

Jim Bridger

Idaho Power owns one-third, or 771 MW (generator nameplate rating), of the Jim Bridger coal-fired power plant located near Rock Springs, Wyoming. The Jim Bridger plant consists of four generating units. PacifiCorp has two-thirds ownership and is the operator of the Jim Bridger facility.

North Valmy

Idaho Power owns 50 percent, or 284 MW (generator nameplate rating), of the North Valmy coal-fired power plant located near Winnemucca, Nevada. The North Valmy plant consists of two generating units. NV Energy has 50 percent ownership and is the operator of the North Valmy facility.

Boardman

Idaho Power owns 10 percent, or 64.2 MW (generator nameplate rating), of the Boardman coal-fired power plant located near Boardman, Oregon. The plant consists of a single generating unit. Portland General Electric (PGE) has 90 percent ownership and is the operator of the Boardman facility.

The 2015 IRP assumes Idaho Power's share of the Boardman plant will not be available after December 31, 2020. The 2020 date is the result of an agreement reached between the Oregon Department of Environmental Quality (ODEQ), PGE, and the EPA related to compliance with Regional Haze Best Available Retrofit Technology (RH BART) rules on particulate matter, sulfur dioxide (SO_2), and nitrogen oxide (NO_x) emissions. At the end of 2014, the net-book value of Idaho Power's share of the Boardman facility was approximately $20.9 million.

Natural Gas Facilities

Langley Gulch

Idaho Power owns and operates the Langley Gulch plant, a nominal 318-MW natural gas-fired CCCT. The plant consists of one 187-MW Siemens STG-5000F4 combustion turbine and one 131.5-MW Siemens SST-700/SST-900 reheat steam turbine. The Langley Gulch plant, located south of New Plymouth in Payette County, Idaho, became commercially available in June 2012.

Danskin

Idaho Power owns and operates the 271-MW Danskin natural gas-fired SCCT facility. The facility consists of one 179-MW Siemens 501F and two 46-MW Siemens–Westinghouse

W251B12A combustion turbines. The Danskin facility is located northwest of Mountain Home, Idaho. The two smaller turbines were installed in 2001, and the larger turbine was installed in 2008. The Danskin units are dispatched when needed to support system load.

Bennett Mountain

Idaho Power owns and operates the Bennett Mountain plant, which consists of a 173-MW Siemens–Westinghouse 501F natural gas-fired SCCT located east of the Danskin plant in Mountain Home, Idaho. The Bennett Mountain plant is also dispatched as needed to support system load.

Salmon Diesel

Idaho Power owns and operates two diesel generation units in Salmon, Idaho. The Salmon units have a combined generator nameplate rating of 5 MW and are operated during emergency conditions, primarily for voltage and load support.

Solar Facilities

In 1994, a 25-kW solar PV array with 90 panels was installed on the rooftop of Idaho Power's corporate headquarters (CHQ) in Boise, Idaho. The 25-kW solar array is still operational, and Idaho Power uses the hourly generation data from the solar array for resource planning.

Idaho Power also uses small PV panels in its daily operations to supply power to equipment used for monitoring water quality, measuring streamflows, and operating cloud-seeding equipment. In addition to these solar PV installations, Idaho Power participates in the Solar 4R Schools Program and owns a mobile solar trailer that can be used to supply power for concerts, radio remotes, and other events.

Net Metering Service

Idaho Power's net metering service allows customers to generate power on their property and connect to Idaho Power's system. For net metering customers, the energy generated is first consumed on the property itself, while excess energy flows out to the company's grid. The majority of net metering customers use solar PV systems. As of May 1, 2015, there were 479 solar PV systems interconnected through the company's net metering service with a total capacity of 3.316 MW. At that time, the company had received completed applications for an additional 48 net metered solar PV systems representing an incremental capacity of 0.498 MW. For further details regarding customer-owned generation resources interconnected through the company's net metering service, see Table 3.3.

Table 3.3 Net metering service customer count and generation capacity as of May 1, 2015

	Number of Customers			Generation Capacity (MW)		
Resource Type	**Active**	**Pending**	**Total**	**Active**	**Pending**	**Total**
Solar PV	479	48	527	3.316	0.498	3.8140
Wind	70	2	72	0.557	0.010	0.5670
Other/hydroelectric	10	–	10	0.147	0.000	0.0147
Total	559	50	609	–	0.508	4.5280

Oregon Solar Photovoltaic Pilot Program and Oregon Solar Photovoltaic Capacity Standard

In 2009, the Oregon Legislature passed Oregon Revised Statute (ORS) 757.365 as amended by House Bill 3690, which mandated the development of pilot programs for electric utilities operating in Oregon to demonstrate the use and effectiveness of volumetric incentive rates for electricity produced by solar PV systems.

As required by the OPUC in Order Nos. 10-200 and 11-089, Idaho Power established the Oregon Solar Photovoltaic Pilot Program in 2010, offering volumetric incentive rates to customers in Oregon. Under the pilot program, Idaho Power acquired 400 kW of installed capacity from solar PV systems with a nameplate capacity of less than or equal to 10 kW. In July 2010, approximately 200 kW were allocated, and the remaining 200 kW were offered during an enrollment period in October 2011. However, because some PV systems were not completed from the 2011 enrollment, a subsequent offering was held on April 1, 2013, for approximately 80 kW.

In 2013, the Oregon Legislature passed House Bill 2893, which increased Idaho Power's required capacity amount by 55 kW. An enrollment period was held in April 2014, and all capacity was allocated, bringing Idaho Power's total capacity in the program to 455 kW.

Under the Oregon Solar PV Capacity Standard as stated in ORS 757.370, Idaho Power is required to either own or purchase the generation from a 500-kW utility-scale solar PV facility by 2020. Under the rules, if the utility-scale facility is operational by 2016, the RECs from the project would be doubled for purposes of complying with the State of Oregon RPS. Idaho Power does not plan to build or acquire the generation from a 500-MW solar facility in Oregon prior to 2016, as the company already has sufficient RECs to meet the Oregon RPS requirement and no near-term needs for additional generation. The company will further evaluate this requirement in the 2017 IRP and determine the best method of meeting the 2020 compliance deadline.

Power Purchase Agreements

Elkhorn Valley Wind Project

In February 2007, the IPUC approved a PPA with Telocaset Wind Power Partners, LLC, a subsidiary of Horizon Wind Energy, for 101 MW of nameplate wind generation from the Elkhorn Valley Wind Project located in northeastern Oregon. The Elkhorn Valley Wind Project was constructed during 2007 and began commercial operations in December 2007. Under the PPA, Idaho Power receives all the RECs from the project.

Elkhorn Valley Wind Project, Union County, Oregon

Raft River Geothermal Project

In January 2008, the IPUC approved a PPA for 13 MW of nameplate generation from the Raft River Geothermal Power Plant (Unit 1) located in southern Idaho. The Raft River project began commercial operations in October 2007 under a PURPA contract with Idaho Power that

was canceled when the new PPA was approved by the IPUC. For the first 10 years (2008–2017) of the agreement, Idaho Power is entitled to 75 percent of the RECs from the project for generation that exceeds 10 aMW monthly. The Raft River geothermal project has rarely exceeded the monthly 10 aMW of generation since 2009, and Idaho Power is currently receiving negligible RECs from the Raft River project. For the second 10 years of the agreement (2018–2027), Idaho Power is entitled to 51 percent of all RECs generated by the project.

Neal Hot Springs Geothermal Project

In May 2010, the IPUC approved a PPA for approximately 22 MW of nameplate generation from the Neal Hot Springs Geothermal Project located in eastern Oregon. The Neal Hot Springs project achieved commercial operation in November 2012. Under the PPA, Idaho Power receives all RECs from the project.

Clatskanie Energy Exchange

In September 2009, Idaho Power and the Clatskanie People's Utility District (Clatskanie PUD) in Oregon entered into an energy exchange agreement. Under the agreement, Idaho Power receives the energy as it is generated from the 18-MW power plant at Arrowrock Dam on the Boise River; in exchange, Idaho Power provides the Clatskanie PUD energy of an equivalent value delivered seasonally—primarily during months when Idaho Power expects to have surplus energy. An energy bank account is maintained to ensure a balanced exchange between the parties where the energy value will be determined using the Mid-Columbia market price index. The Arrowrock project began generating in January 2010, and the agreement term extends through 2015. Idaho Power also retains the right to renew the agreement through 2025. The Arrowrock project is expected to produce approximately 81,000 MWh annually.

Public Utility Regulatory Policies Act

In 1978, the US Congress passed PURPA, requiring investor-owned electric utilities to purchase energy from any qualifying facility (QF) that delivers energy to the utility. A QF is defined by FERC as a small renewable-generation project or small cogeneration project. The acronym CSPP (cogeneration and small-power producers) is often used in association with PURPA. Individual states were tasked with establishing PPA terms and conditions, including the price each state's utilities are required to pay as part of the PURPA agreements. Because Idaho Power operates in Idaho and Oregon, the company must adhere to both the IPUC rules and regulations for all PURPA facilities located in Idaho and the OPUC rules and regulations for all PURPA facilities located in Oregon. The rules and regulations are similar but not identical for the two states. Because Idaho Power cannot accurately predict the level of future PURPA development, only signed contracts are accounted for in Idaho Power's resource planning process.

Generation from PURPA contracts has to be forecasted early in the IRP planning process to update the load and resource balance. The PURPA forecast used in the 2015 IRP was completed in October 2014.

As of March 31, 2015, Idaho Power had 133 PURPA contracts with independent developers for approximately 1,302 MW of nameplate capacity. These PURPA contracts are for low-head hydroelectric projects on various irrigation canals, cogeneration projects at industrial facilities, wind projects, solar projects, anaerobic digesters, landfill gas, wood-burning facilities,

and various other small, renewable-power generation facilities. Of the 133 contracts, 105 were on-line as of March 31, 2015, with a cumulative nameplate rating of approximately 781 MW. Figure 3.5 shows the percentage of the total PURPA capacity of each resource type under contract.

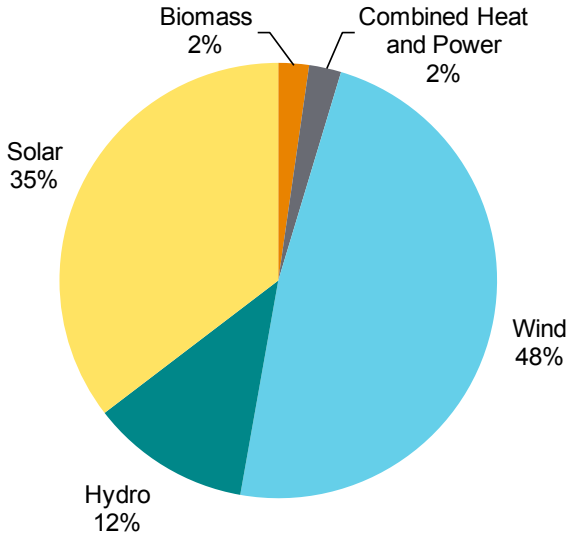


Figure 3.5 PURPA contracts by resource type

Published Avoided Cost Rates

A key component of PURPA contracts is the energy price contained within the agreements. The federal PURPA regulations specify that a utility must pay energy prices based on the utility's avoided cost. Subsequently, the IPUC and OPUC have established specific rules and regulations to calculate the published avoided cost rate Idaho Power is required to include in PURPA contracts. Some of the general guidelines are outlined below.

Published Avoided Cost Eligibility

- *Idaho*—Wind and solar projects with a nameplate rating of less than 100 kW and all other projects with less than 10 aMW calculated on a monthly basis
- *Oregon*—All projects with a nameplate rating of less than 10 MW

For all projects not eligible for the published avoided cost rate, a unique negotiated avoided cost is calculated for each project. The basis for this negotiated avoided cost rate is the commission approved incremental cost IRP avoided cost methodology. In Idaho and Oregon, the published avoided cost is different based on the resource type (i.e. wind, solar, hydro, base load).

REC Ownership

- *Idaho*—Projects that contract with Idaho Power using the published avoided cost rate will retain all RECs associated with the project. If the PURPA contract contains negotiated rates, IPUC Order No. 32697, issued December 18, 2012, stipulates the RECs will be equally shared between Idaho Power and the project owner.
- *Oregon*—The project owner retains all rights to the RECs associated with the project.

On January 30, 2015, Idaho Power filed a petition with the IPUC requesting the required contract term within new Idaho PURPA contracts be revised from 20 to 2 years. The IPUC opened case IPC-E-15-01 to address this matter, and a hearing is scheduled for June 29, 2015. IPUC Order No. 33222, issued February 6, 2015, temporarily revised the contract term from 20 to 5 years during the processing of the case.

In April 2012, the OPUC issued Order No. 12-146, which opened OPUC Docket UM 1610. Docket UM 1610 addresses many of the same PURPA issues identified in the recent Idaho PURPA cases as well as unique PURPA issues associated with Oregon. Parties have been filing testimony and comments in the case. The initial hearing was held in Salem, Oregon, on May 23, 2013. This case is moving into its second and third phases, continuing to review and address numerous PURPA-related issues.

On December 18, 2012, the IPUC issued Order No. 32697. Order No. 32697 included new rules and regulations in regard to the numerous PURPA issues presented in the various cases that began in November 2010. Some highlights are as follows:

- The published avoided cost rate is available only for wind and solar projects with a nameplate rating of less than 100 kW.
- For all other resource types, the eligibility cap remains at 10 aMW.
- Idaho Power's proposed incremental cost IRP methodology was approved to calculate the avoided cost pricing for projects ineligible for published avoided costs.
- A unique published avoided cost was established for wind, solar, hydroelectric, canal drop hydroelectric, and other projects.
- The QF project owner retains the RECs associated with the project for QF contracts containing published avoided cost rates.
- Idaho Power shall be entitled to 50 percent of the RECs for QF contracts that contain negotiated rates.

On May 6, 2013, the IPUC issued Order No. 32802 concerning the reconsideration of Case No. GNR-E-11-03. Order No. 32802 affirms many of the commission rulings in Order No. 32697. PURPA contracting continues to be an issue in Idaho, and approximately 200 MW of various QF projects currently have some form of a filed dispute in regard to PURPA contracts with Idaho Power.

Wholesale Contracts

Idaho Power currently has no long-term wholesale energy contracts (no long-term wholesale sales contracts and no long-term wholesale purchase contracts). The Elkhorn, Raft River Geothermal, Neal Hot Springs, and Clatskanie Exchange contracts were described previously in the Power Purchase Agreements section in this chapter.

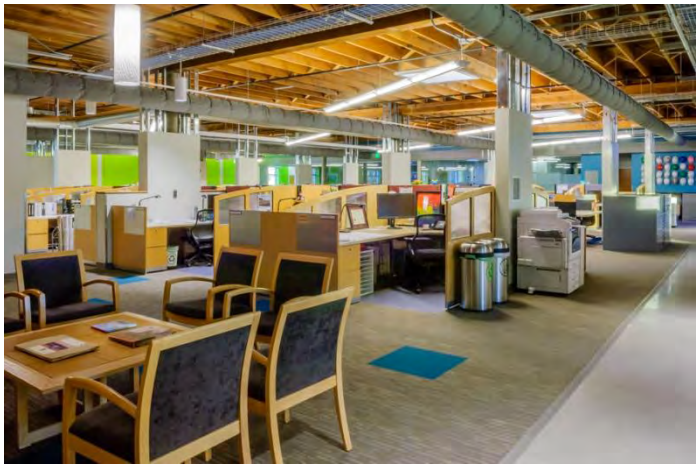
Market Purchases and Sales

Idaho Power relies on regional markets to supply a significant portion of energy and capacity needs during certain times of the year. Idaho Power is especially dependent on the regional markets during peak-load periods, and the existing transmission system is used to import the energy purchases. A reliance on regional markets has benefited Idaho Power customers during times of low prices through the import of low-cost energy. Customers also benefit from sales revenues associated with surplus energy from economically dispatched resources.

4. Demand-Side Resources

Introduction

Demand-side resources have been the first resource choice in every IRP since 2004. No supply-side generation resource is considered as part of Idaho Power's plan until all future cost-effective achievable potential energy efficiency and forecasted demand response is accounted for and credited against future loads. In the 2015 IRP, demand response will provide 390 MW of peak summer reduction, while energy efficiency will reduce average annual loads by 301 aMW and 473 MW of peak reduction by the year 2034.



CSHQA's new offices received the City of Boise Building Excellence awards for Best Sustainable Commercial Project and Best Overall Project for 2014. CSHQA participated in Idaho Power's Building Efficiency program.

Demand-Side Management Program Overview

DSM programs are an essential part of Idaho Power's resource strategy, and its portfolio of programs consists of demand response, energy efficiency, and market transformation programs. The three program categories provide different system benefits. Demand response programs reduce peak loads through customer behavior or automations that respond during periods of extreme loads when all other resources, including market purchases, are at their maximum capacity. Energy efficiency programs target year-round energy and demand reduction and are the demand-side alternatives to supply-side base load resources. Market transformation targets energy savings through engaging and influencing large national and regional organizations to promote energy efficiency. Idaho Power has collaborated with other regional utilities and organizations and funded Northwest Energy Efficiency Alliance (NEEA) market transformation activities since 1997. Energy efficiency, demand response, and market transformation programs are offered to all four major customer classes: residential, irrigation, commercial, and industrial. Education programs and services are also offered to customers to support, promote, and encourage efficiency efforts.

Cost-effectiveness analyses, which indicate whether the benefits of these programs exceed the costs to administer them along with the costs incurred by participants, are published annually. The most recent analysis can be found in the *Demand-Side Management 2014 Annual Report Supplement 1: Cost-Effectiveness*. Each program and its component measures in the existing portfolio of demand-side resources are reviewed for their load impact over the 20-year IRP planning horizon as part of the IRP process. Additionally, in 2014 Idaho Power contracted with Applied Energy Group (AEG) to conduct an energy efficiency potential study that resulted in a forecast of energy savings over the 20-year IRP planning period. The resulting AEG forecast and program history were analyzed against the load forecast to ensure the energy efficiency

forecasted by AEG was credited with offsetting future loads. Details on the integration of the energy efficiency forecast are found in *Appendix A—Sales and Load Forecast*, *Appendix B—Demand-Side Management 2014 Annual Report*, and *Appendix C—Technical Appendix*.

DSM Planning Changes from the 2013 IRP

Demand response and market transformation were considered differently in the 2015 IRP than the previous 2013 plan. Since market transformation was included in the 2014 AEG study, market transformation savings are considered a demand-side resource in the 2015 IRP, whereas in the past market transformation savings have been excluded from resource planning. In the 2015 IRP, demand response was treated as both a committed resource based on cost-effectiveness and as a potential new future resource addition beyond the committed resource level in select portfolios.

The 2013 IRP load and resource balance analysis demonstrated no capacity deficits in the near term. As a consequence, Idaho Power temporarily suspended two of its three demand response programs for summer 2013 under IPUC Case No. IPC-E-12-29 and Tariff Advice No. 13-04 with the OPUC. Through IPUC Case No. IPC-E-13-14 (Order No. 32923) and OPUC Case No. UM 1653 (Order No. 13-482), Idaho Power and interested parties reached a settlement agreement to continue the company's demand response programs for 2014 and beyond.

In the 2015 IRP, 390 MW of demand response capacity are included in every portfolio, and up to an additional 60 MW are in some portfolios as needed. In 2014, these programs cost $10.6 million; had the programs been used for the maximum number of hours, the cost would have been approximately $13.8 million. These costs represent approximately $6 million dollars in savings compared to 2012 ($21.2 million) and are significantly less than the annual value of $16.7 million agreed on in the settlement agreement. Another result of the settlement was guidance on how to operate the programs in years where they may not be short-term peak capacity deficits. To maintain the engagement of participants in demand response programs, Idaho Power will conduct a minimum of three events, even when extreme loads, low water, and extreme temperatures that demand response programs were designed to meet do not occur. In addition to helping retain participants, these three events will allow Idaho Power to evaluate and improve operations of the programs. Since demand response is considered a committed resource to the company, the potential load reduction of 390 MW from demand response was applied to future peak summer loads prior to the selection of additional resources to meet future peak deficits.

Market transformation achieves energy efficiency savings through engaging and influencing large national and regional companies and organizations. These organizations influence the design of energy efficiency into products, services, and practices that improve their energy efficiency. Idaho Power achieves market transformation savings primarily through its participation in NEEA. Idaho Power has been a funding member of NEEA since its inception in 1997.

Historically, Idaho Power has treated the savings reported by NEEA separately from savings from company run and administered efficiency programs. While the company has been supporting market transformation since the regional collaborative started, the value in the

programs for Idaho Power was to promote new potential energy-savings technologies and to look for new opportunities to be adopted into Idaho Power's program offerings. Examples of this include residential energy-efficient lighting that started out as a NEEA initiative to promote compact fluorescent technologies and transitioned to utility programs across the Northwest, including Idaho Power. Another reason affecting how market transformation savings were used in resource planning was related to how savings were attributed to utilities. Until 2010, NEEA primarily apportioned savings by how much each regional funder utility contributed to their various initiatives and put very little effort into assigning savings to geographic locations. This made it difficult to count on NEEA savings that may or may not be actually reducing Idaho Power loads while reducing regional system loads.

Since 2010, NEEA has been working on and continuously improving its ability to verify savings at the service-area level of its funders through evaluation and increased data collection. This allows Idaho Power to include market transformation savings as part of the company's efforts to meet IRP energy-savings targets. Another consideration to fully integrate market transformation into the IRP is that the AEG potential study that determines the energy efficiency forecast is agnostic to where the savings for any potential measure or technology come from or who provides them. The forecasted future savings can come from market transformation efforts done on a regional basis or from a traditional utility-administered program.

Program Screening

All DSM programs and measures included in Idaho Power's current portfolio of programs and the forecast have been screened for cost-effectiveness. Cost-effectiveness analyses of DSM forecasts for the 2015 IRP are presented in more detail in *Appendix C—Technical Appendix*. *Appendix B—Demand-Side Management 2014 Annual Report* contains a detailed description of Idaho Power's 2014 energy efficiency program portfolio along with historical program performance. A complete review of Idaho Power's DSM programs, evaluations, and cost-effectiveness can be found in the 2014 annual report filing, *Demand-Side Management 2014 Annual Report*, *Supplement 1: Cost-Effectiveness*, and *Supplement 2: Evaluation*, which are available on Idaho Power's website at idahopower.com/EnergyEfficiency/reports.cfm.

DSM Program Performance

While the IRP planning process primarily looks forward, it is also important to review historical DSM performance to understand the effects on system load. Accumulated annual savings from energy efficiency investments grow over time based on measure lives of the efficient equipment and measures adopted and installed by customers each year. Additionally, past performance of demand response programs has changed over time as the design and use of the programs have evolved.

Energy Efficiency Performance

Energy efficiency investments since 2002 have resulted in a cumulative average annual load reduction of 167 aMW or over 1.4 million MWh of reduced supply-side energy production to customers through 2014. Figure 4.1 shows the cumulative annual growth in energy efficiency effects over the 13-year period from 2002 through 2014, along with the associated IRP targets developed as part of the IRP process since 2004.

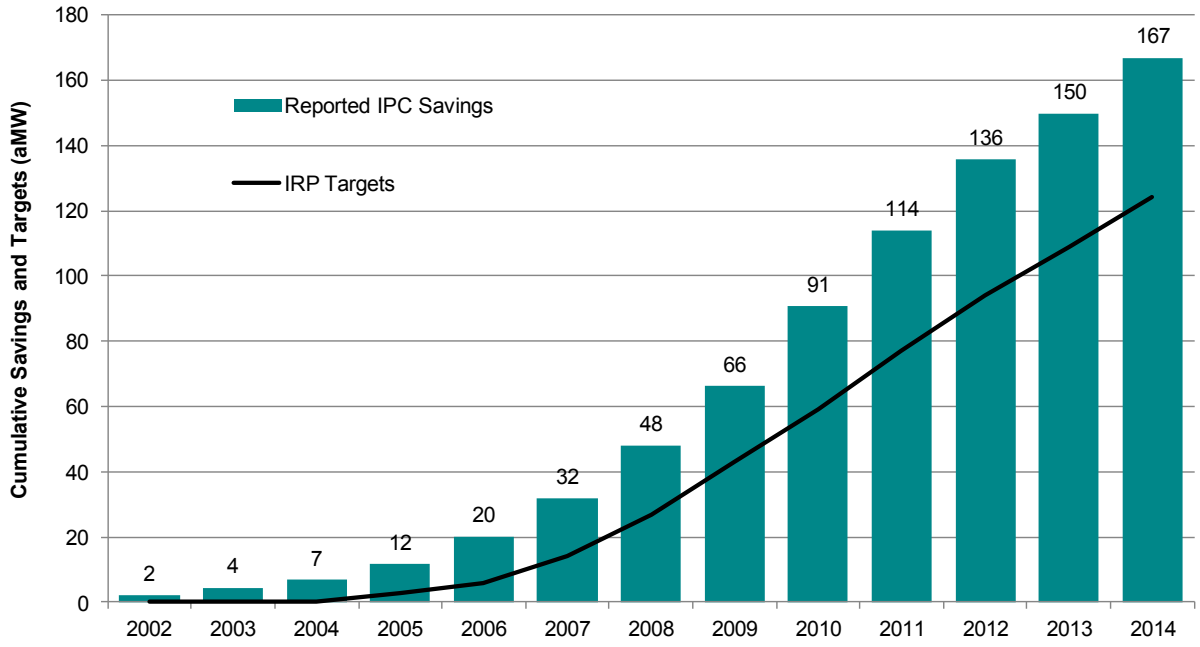


Figure 4.1 Cumulative energy efficiency savings, 2002–2014 (aMW)

Demand Response Performance

Demand response resources have been part of the demand-side portfolio since the 2004 IRP. The current demand response portfolio is comprised of three distinct programs that work together as one resource. Each program targets a different customer class. Table 4.1 lists the three programs that make up the current demand response portfolio, along with the different program characteristics. The Irrigation Peak Rewards program represents the largest percent of potential demand reduction. During the 2014 summer season, participating irrigation program customers contributed 78 percent of the total potential demand reduction, or 295 MW. More details on Idaho Power's demand response programs can be found in *Appendix B—Demand-Side Management 2014 Annual Report.*

Table 4.1 Current demand response programs 2014 performance

Program	Customer Class	Reduction Technology	2014 Peak Performance (MW)	Percent of Total 2014 Peak Performance
A/C Cool Credit	Residential	Central A/C	44	12%
Irrigation Peak Rewards	Irrigation	Pumps	295	78%
FlexPeak Management	Commercial, industrial	Various	40	11%
		Total	**378**	

Figure 4.2 shows the historical annual demand response program capacity between 2004 and 2014 along with associated IRP targets between 2004 and 2012. There were no targets for 2013 to 2014 in the 2013 IRP. The large jump in demand response capacity from 61 MW in 2008 to 218 MW in 2009 was a result of transitioning the majority of the Irrigation Peak Rewards

program to a dispatchable program. The demand response capacity in 2011 and 2012 included 320 and 340 MW of capacity, respectively, from the Irrigation Peak Rewards program, which was not used based on the lack of need and the variable cost to dispatch the program. The reported capacity value was lower in 2013 because of the one-year suspension of the irrigation and residential programs.

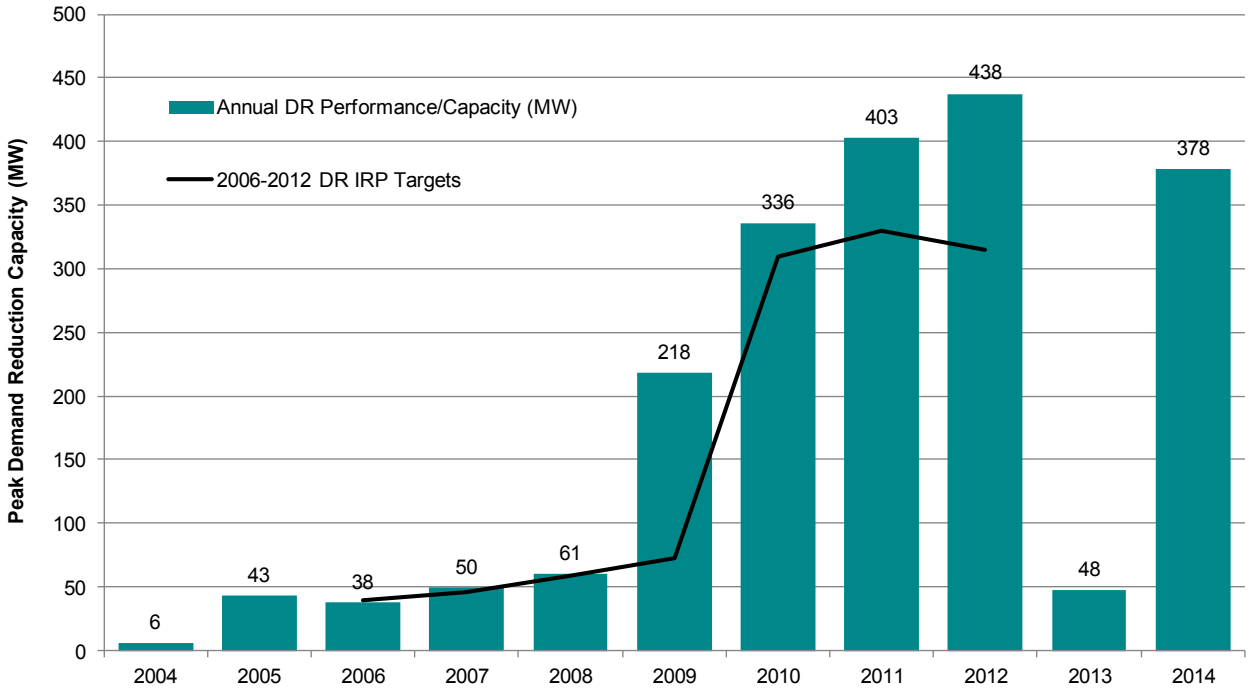


Figure 4.2 Demand response peak reduction capacity and IRP targets, 2004–2014 (MW)

Committed Energy Efficiency Forecast

For the 2015 IRP, AEG was retained to update the previous study from 2012 and provide an updated 20-year comprehensive view of Idaho Power's energy efficiency potential. The objectives of the 2014 potential study were as follows:

- Incorporate the rapid changes in residential lighting potential based on the impacts from light-emitting diode (LED) lighting.
- Provide credible and transparent estimation of the technical, economic, and achievable energy efficiency potential by year over 20 years (2015–2034) within the Idaho Power service area.
- Assess potential energy savings and peak demand associated with each potential area by energy efficiency measure or bundled measure and sector.
- Provide a dynamic model that will support the potential assessment and allow testing of the sensitivity of all model inputs and assumptions.
- Develop a final report, including summary data tables and graphs reporting incremental and cumulative potential by year from 2015 through 2034.

Because the potential study's market characterization process bundles industries and building types into homogenous groupings, Idaho Power's special-contract customers were treated outside of the potential study model. Forecasts for these unique customers, who tend to be very active in efficiency, were based on the combined customer group's history of participation along the near-term pipeline of projected projects.

In the AEG study, the energy efficiency potential estimates represent gross savings developed into three types of potential: technical potential, economic potential, and achievable potential. Technical and economic potential are both theoretical limits to efficiency savings. Achievable potential embodies a set of assumptions about the decisions consumers make regarding the efficiency of the equipment they purchase, the maintenance activities they undertake, the controls they use for energy-consuming equipment, and the elements of building construction. These levels are described below.

- *Technical*—Technical potential is defined as the theoretical upper limit of energy efficiency potential. Technical potential assumes customers adopt all feasible measures regardless of cost. At the time of equipment replacement, customers are assumed to select the most efficient equipment available. In new construction, customers and developers are also assumed to choose the most efficient equipment available. Technical potential also assumes the adoption of every other applicable measure available. The retrofit measures are phased in over a number of years, which is greater for higher-cost measures.

- *Economic*—Economic potential represents the adoption of all cost-effective energy efficiency measures. In the potential study, the total resource cost (TRC) test, which compares lifetime energy and capacity benefits to the incremental cost of the measure, is applied. Economic potential assumes customers purchase the most cost-effective option at the time of equipment failure and also adopt every other cost-effective and applicable measure.

- *Achievable*—Achievable potential takes into account market maturity, customer preferences for energy-efficient technologies, and expected program participation. Achievable potential establishes a realistic target for the energy efficiency savings a utility can achieve through its programs. It is determined by applying a series of annual market-adoption factors to the economic potential for each energy efficiency measure. These factors represent the ramp rates at which technologies will penetrate the market.

The potential study followed a standard approach in developing the achievable potential. First, the market was characterized by customer class. The classification phase included segmenting the market by housing type for residential and understanding the various industries and building types within the commercial and industrial customer classes. Saturations of end-use technologies within customer segments are assessed to help determine which technologies are available for efficient upgrades. The next phase included screening measures and technologies for cost-effectiveness, then assessing the adoption rates of technologies to determine the forecast of achievable potential. More detailed information about cost-effectiveness methodologies and approaches can be found in *Appendix C—Technical Appendix*.

The annual savings potential forecast is provided to Idaho Power in gigawatt-hours (GWh), where it is converted to hourly, then monthly, demand reduction (aMW) to compare with supply-side resources for the IRP analysis, the savings are shaped by end-use load shapes that spread the forecasted savings across all hours of the year. The load shapes used to allocate savings by end-use were provided by AEG as part of the study deliverables. All reported energy efficiency and demand response forecasts are expressed at generation level and therefore include line losses of 9.6 percent for energy and 9.7 percent for peak demand to account for energy that would have been lost as a result of transmitting energy from a supply-side generation resource to the meter level.

Table 4.2 shows the forecasted potential effect of the current portfolio of energy efficiency programs for 2015 to 2034 in five-year blocks in terms of cumulative average annual energy reduction (aMW) by customer class. In 2019, the forecast reduction for 2015 to 2019 programs is forecast to be 84.3 aMW; by 2024 (halfway through the planning period), the cumulative reduction across all customer classes increases to 169.4 aMW. By the end of the IRP planning horizon in 2034, 300.8 aMW of reduction are forecast to come from the energy efficiency portfolio, with 55 percent of forecasted reduction coming from programs serving commercial and industrial customers. Detailed annual forecast values can be found in *Appendix C—Technical Appendix*.

Table 4.2 Total energy efficiency portfolio forecasted effects (2015–2034) (aMW)

	2015	2019	2024	2029	2034
Industrial/commercial/special contracts	8	46	93	138	167
Residential	3	28	55	85	111
Irrigation	1	11	22	23	23
Total*	**12**	**84**	**169**	**246**	**301**

*Totals may not add exactly due to rounding.

Table 4.3 shows the cost-effectiveness summary from the potential study. The table shows the NPV analysis of the 20-year forecast of the TRCs and DSM preliminary alternative costs or program benefits. TRCs account for both the costs to administer the programs and the customer's incremental cost to invest in efficiency technologies and measures offered through the programs. The benefit of the programs is avoided energy, which is calculated by valuing energy savings against the avoided generation costs of Idaho Power's existing marginal resources.

Table 4.3 Total energy efficiency portfolio cost-effectiveness summary

	2034 Load Reduction (aMW)	2034 Peak Load Reduction (MW)	Resource Costs ($000s) (20-Year NPV)	Total Benefits ($000s) (20-Year NPV)	TRC: Benefit/ Cost Ratio	TRC Levelized Costs (cents/kWh)
Residential	111	175	$425,360	$691,151	1.6	9.8
Industrial/commercial/ special contract	167	226	$253,982	$618,633	2.4	3.3
Irrigation	23	72	$139,206	$222,009	1.6	10.3
Total	**301**	**473**	**$818,548**	**$1,531,793**	**1.9**	**6.1**

The value of avoided energy over the 20-year investment in the energy efficiency measures was almost twice the TRC when comparing benefits and costs resulting in an overall benefit/cost ratio of two. The levelized cost to reduce energy demand by 301 aMW and peak demand by 473 MW is 6.1 cents per kWh from a TRC perspective.

Once the energy efficiency forecast is complete, the forecasted energy efficiency is included in the IRP planning horizon and the load and resource balance analysis. Planning assumptions in the energy efficiency potential forecast include new programs, technology, known changes to codes and standards, customer adoption behavior, and cost-effectiveness that are explicitly incorporated into the potential study and reflect differences between the energy efficiency forecast and the amount of efficiency accounted for in the load forecast. A key difference between the two views of efficiency is that the load forecast accounts for energy efficiency effects based on previous years' program performance while the forecast from the potential study is a more prospective approach. The amount of energy efficiency not captured by the load forecast trends is accounted for in the load and resource balance analysis.

Committed Demand Response Resources

Under the current program design and participation levels, demand response from all programs is forecast to provide 390 MW of peak reduction during July throughout the IRP planning period with additional program potential available during June and August. The committed demand response included in the IRP has a capacity cost of $33 per annual kW per year.

Typical irrigation pivot supplied by a pump participating in the Irrigation Peak Rewards demand response program.

Non-Cost-Effective DSM Resource Options

AEG provided an additional potential study analysis to model additional achievable potential that would occur if the cost-effectiveness benefit/cost ratio requirements of a TRC test were changed from the standard requirement of one or greater down to a value of 0.8. The revised assumptions in the model produced a non-cost-effective energy-savings potential of 16 aMW and 24 MW of peak reduction over the 20-year IRP planning horizon. The 20-year present value cost of the additional efficiency was determined to have a levelized cost of 9.1 cents per kWh, which is 3.0 cents higher than the 20-year levelized cost of the achievable potential within the normal parameters of the TRC test. The additional DSM amount was made available as a resource in three of the analyzed portfolios.

Additional Demand Response

An additional 60 MW of demand response were made available for peak summer reduction in some portfolios. If Idaho Power were to pay increased incentive amounts to customers, there would be added available capacity to expand the Irrigation Peak Rewards program in future years. While the current demand response portfolio cost is $33 per kW per year, this additional demand response capacity would cost approximately $51 per kW per year. This additional demand response capacity is included in some portfolios beginning in the year 2021 and is included in the preferred portfolio in 2030.

Energy Efficiency Working Group

On November 4, 2014, the IPUC issued Order No. 33161 (Case No. IPC-E-14-04) finding that Idaho Power's 2013 DSM expenses were prudently incurred. On November 7, 2014, the IPUC issued Errata to Order No. 33161, stating in relation to issues raised in the case:

> The Commission agrees that the issues raised by Staff and other parties are significant and warrant a more in-depth review. We direct the parties to do so in the context of the Company's next Integrated Resource Plan filing.

In response to the Errata, Idaho Power organized an Energy Efficiency Working Group inviting members of the IRPAC, public participants in the IRP process, and the Energy Efficiency Advisory Group (EEAG). The Energy Efficiency Working Group held two public meetings in December 2014.

The first Energy Efficiency Working Group meeting included a discussion of a broad range of energy efficiency and resource planning issues that can be classified into two general categories: 1) strategies related to energy-efficiency program delivery and 2) the treatment of energy efficiency in the resource planning process. The second Energy Efficiency Working Group meeting focused on how energy efficiency as a resource should be treated in the IRP. Topics discussed at the second working group meeting included the following:

- A comparison presented by AEG of potential studies from other regional utilities
- A comparison presented by IPUC staff of Idaho Power's inclusion of energy efficiency in the IRP to the inclusion of energy efficiency by other regional utilities
- An Idaho Power-led discussion of the inclusion of transmission and distribution investment deferral into the benefits in the DSM cost-effectiveness analysis.

Through correspondence with working group participants, Idaho Power expressed the view that its current treatment of energy efficiency in the resource planning process appropriately balances the need for responsible and effective resource planning and the desire to pursue all cost-effective and achievable energy efficiency. Idaho Power also recognizes that achieving those balanced objectives on an ongoing basis requires continued review and evaluation of the planning process, as well as an awareness of related industry best practices.

Idaho Power has committed to continuing to investigate the extent to which transmission and/or distribution benefits result from energy efficiency measures and programs, as well as the approximate value of such benefits. Idaho Power presented a status update of this investigation at the May 7, 2015, IRPAC meeting. In the May 7, 2015, IRPAC meeting, Idaho Power indicated the study of transmission and distribution investment deferment is ongoing. Actions to be taken as part of the ongoing study include a review of transmission and distribution investments related to growth, an evaluation of the effectiveness of energy efficiency measures and programs in deferring transmission and distribution investment, and an estimate of the deferral value for those cases with the potential for transmission and/or distribution investment deferment.

Idaho Power is also committed to continuing to discuss the program delivery issues identified by working group participants, by IPUC staff, and by some intervenors in comments filed in Case No. IPC-E-14-04. The company plans to use EEAG as the forum to provide customers, regulatory staff, and other interested stakeholders an opportunity to provide advice and recommendations to Idaho Power on formulating, implementing, and evaluating energy efficiency and demand response programs and activities.

Conservation Voltage Reduction

The goal of conservation voltage reduction (CVR) is to reduce electrical demand and energy by minimizing the distribution feeder voltage while providing service voltage within the standard operation range. Idaho Power participated in a northwest CVR pilot and implemented CVR on a few distribution feeders. In the 2013 IRP, Idaho Power proposed to validate the energy savings and reduced peak demand of CVR using new technologies and methods of measurement. Idaho Power included the validation plan (*Conservation Voltage Reduction Enhancements Project*) in its *2014 Smart Grid Report*. The project scope includes the following:

- Validate the energy and demand savings associated with CVR at the customer level
- Quantify the costs and benefits associated with implementing CVR
- Determine methods for expanding the CVR program to additional feeders
- Pilot methods for making Idaho Power's CVR program more dynamic
- Determine methods for the ongoing measurement and validation of the CVR program's effectiveness

The CVR measurement and verification process has been identified. Idaho Power has installed the infrastructure to evaluate CVR energy savings and demand reduction at seven substations in six different weather zones. In addition, new technology has been deployed on test feeders to evaluate its effectiveness in making CVR more dynamic. Hourly customer usage data will be collected from the Advanced Metering Infrastructure (AMI) system throughout 2015. This usage data will be analyzed to determine how CVR impacts the customer classes in weather zones across Idaho Power's service area. Idaho Power expects to complete the CVR analysis in 2016. Extending CVR measures to other Idaho Power facilities will then be evaluated.

5. Supply-Side Generation and Storage Resources

Supply-side resources are traditional generation resources. Early IRP utility commission orders directed Idaho Power and other utilities to give equal treatment to both supply-side and demand-side resources. As discussed in Chapter 4, demand-side programs are an essential component of Idaho Power's resource strategy. The following sections describe the supply-side resources and storage technologies considered when Idaho Power developed the resource portfolios for the 2015 IRP. Not all supply-side resources described in this section were included in the preliminary resource portfolios, but every resource described was considered.

The primary source of cost information for the 2015 IRP is a report titled *Lazard's Levelized Cost of Energy Analysis*.[6] Lazard, a leading independent financial advisory and asset management firm, issued the levelized cost report in September 2014. Other information sources were relied on or considered on a case-by-case basis depending on the credibility of the source and the age of the information. For a full list of all the resources considered and cost information, see figures 7.5 and 7.6 in Chapter 7. All cost information presented is in 2015 dollars.

Renewable Resources

Renewable resources are the foundation of Idaho Power, and the company has a long history of renewable resource development and operation. In the 2015 IRP, renewable resources were included in many of the portfolios analyzed as part of meeting the EPA's proposed CAA Section 111(d) regulation. Renewable resources are discussed in general terms in the following sections.

Solar

The primary types of solar technology are utility-scale PV and distributed PV. In general, PV technology absorbs solar energy collected from sunlight shining on panels of solar cells, and a percentage of the solar energy is absorbed into the semiconductor material. The energy accumulated inside the semiconductor material energizes the electrons and creates an electric current. The solar cells have one or more electric fields that force electrons to flow in one direction as a direct current (DC). The DC energy is passed through an inverter, converting it to alternating current (AC) that can then be used on-site or sent to the grid. Even on cloudy days, a PV system can still provide 15 percent of the system's rated output.

Insolation is a measure of solar radiation reaching the earth's surface and is used to evaluate the solar potential of an area. Typically, insolation is measured in kWh per square meter (m^2) per day (daily insolation average over a year). The higher the insolation number, the better the solar power potential for an area. National Renewable Energy Laboratory (NREL) insolation charts show the desert southwest has the highest solar potential in the US.

In designing initial portfolios that included solar resources, Idaho Power chose the utility-scale PV technology because of its compliance to EPA's proposed CAA Section 111(d) regulation,

[6] Lazard. 2014. Lazard's levelized cost of energy analysis. http://www.lazard.com/PDF/Levelized%20Cost%20of%20Energy%20-%20Version%208.0.pdf.

its flexibility, and its lower overall cost. Solar PV technology has existed for a number of years but has historically been cost prohibitive. Recent improvements in technology and manufacturing, combined with increased demand due to state RPSs, have made PV resources more cost competitive with other renewable and conventional generating technologies.

The capital-cost estimate used in the 2015 IRP for utility-scale PV resources is based on the 2014 Lazard report, which estimates a cost of $1,500 per kW for fixed panels and $1,750 per kW for PV with a single-axis tracking system. The 20-year levelized cost of production for fixed panels is $118 per MWh based on a 21.5-percent annual capacity factor and $109 per MWh for PV with a single-axis tracking system and a 26.8-percent annual capacity factor. In attempting to capture the decreasing cost of solar, Idaho Power used the 2017 forecast provided by Lazard of $1,250 per kW for PV with a single-axis tracking system.

To account for the decreasing cost trend seen in PV resources over the past few years, the 2015 IRP assumes solar PV costs remain fixed over the 20-year planning period. In comparison, other resource costs are escalated at 2.2 percent over the same 20 years. Therefore, in real-dollar terms, solar PV costs decline over the 20-year planning period. Idaho Power will continue to closely follow the decreasing price trend of solar PV as this technology continues to become more cost competitive with more traditional resource alternatives.

Solar Capacity Credit

Idaho Power reviewed the solar capacity credit calculations due to comments received during the 2013 IRPAC meetings as well as comments received after filing the 2013 IRP. Idaho Power, interested members of the IRPAC, and interested members of the public formed a study group separate from the IRPAC to evaluate solar peak-hour capacity factors. The group formally met in September and October, and Idaho Power had additional informal meetings and conversations with members of the study group. Idaho Power updated the solar PV peak-hour capacity factors based on guidance from the members of the solar work group.

Idaho Power simulated solar generation for water years 2011 through 2013 as part of the solar integration study (data for the period October 1, 2010, through September 30, 2013). Idaho Power used the simulated solar generation combined with actual load data from the same time period to estimate the solar peak-hour capacity factors. In essence, the estimation used the system load data to identify the highest 150 load hours, used the simulated solar generation data to estimate the time-coincident simulated solar generation, and calculated a weighted average of the solar peak-hour capacity factor where the frequency of the hour was used as the weight in the weighted average calculation. The steps of the process are as follows:

1. Identify the 150 highest load hours from 2011 through 2013 (all are summer hours).

2. Determine the simulated solar generation during each of the 150 highest load hours. Solar generation simulation is from the Idaho Power solar integration study and is simulated at five-minute intervals at a set of utility-scale solar generation sites across Idaho Power's service area. The five-minute data was compiled into an average for the hour.

3. Group the solar generation by clock hour for the 150 highest load hours (e.g., a list of all the solar generation values for the clock hour from 2:00 p.m. to 3:00 p.m. during the 150 highest load hours).

4. Estimate the 90th percentile exceedance for each clock hour represented in the 150 highest load hours (among the highest 150 load hours, during the clock hour starting at xx:00, 9 times out of 10, the solar generation was simulated to be at least xx percent of the maximum possible delivered solar generation).

5. Calculate a weighted average of the solar generation for the series of clock hours; the clock hours are weighted by the proportion the clock hour is represented in the top 150 load hours.

Idaho Power used the same process for estimating fixed-panel generation systems and solar tracking generation.

The solar capacity credit is expressed as a percentage of installed AC nameplate capacity. The solar capacity credit is used to determine the amount of peak-hour capacity delivered to the Idaho Power system from a solar PV plant considered as a new IRP resource option. The solar capacity credit values used in the 2015 resource plan are reported in Table 5.1.

Table 5.1 Solar capacity credit values

PV System Description	Peak-Hour Capacity Credit
South orientation	28.4%
Southwest orientation	45.5%
Tracking	51.3%

Geothermal

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. The flashed steam technology requires higher water temperatures. Most 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 remains somewhat uncertain. 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. Flashed steam plants are applicable for geothermal resources where the fluid temperature is 300º Fahrenheit (F) or greater. Binary-cycle technology is used for lower-temperature geothermal resources. In a binary-cycle geothermal plant, geothermal water is pumped to the surface 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 in a closed system and is reused continuously in a binary-cycle plant. The primary fluid (the geothermal water) is returned to the geothermal reservoir through injection wells.

Cost estimates and operating parameters used for binary-cycle geothermal generation in the 2015 IRP are based on data from independent geothermal developers and cost information from a PPA Idaho Power has with U.S. Geothermal, Inc., for the generation from the Raft River Geothermal Project located in southern Idaho. The capital-cost estimate used in the 2015 IRP for geothermal resources is $4,021 per kW, and the 25-year levelized cost of production is $101 per MWh based on a 90-percent annual capacity factor.

Hydroelectric

Hydroelectric power is the foundation of Idaho Power's generation fleet. The existing generation is low cost and does not emit potentially harmful pollutants. Idaho Power believes the development of new, large hydroelectric projects is unlikely because few appropriate sites exist and because of environmental and permitting issues associated with new, large facilities. However, small hydroelectric sites have been extensively developed in southern Idaho on irrigation canals and other sites, many of which have PURPA contracts with Idaho Power.

Small Hydroelectric

Because small hydroelectric projects, such as ROR and projects requiring small or no impoundments, do not have the same level of environmental and permitting issues as large hydroelectric projects, the IRPAC expressed an interest in evaluating small hydroelectric in the 2015 IRP. The potential for new, small hydroelectric projects was studied by the Idaho Strategic Energy Alliance's Hydropower Task Force, and the results released in May 2009 indicate between 150 MW to 800 MW of new hydroelectric resources could be developed in Idaho. These figures are based on potential upgrades to existing facilities, undeveloped existing impoundments and water delivery systems, and in-stream flow opportunities. The capital-cost estimate used in the IRP for small hydroelectric resources is $3,600 per kW, and the 75-year levelized cost of production is $159 per MWh.

Shoshone Falls Expansion Project

In August 2006, Idaho Power filed a license amendment application with FERC to expand the Shoshone Falls Project from 12.5 MW to 61.5 MW. The project currently has three generator/turbine units with nameplate capacities of 11.5 MW, 0.6 MW, and 0.4 MW. The expansion project involves replacing the two smaller units with a single 50-MW unit that will result in a net expansion of 49 MW.

In July 2010, FERC issued a license amendment for the project allowing two years to begin construction and five years to complete the project. Idaho Power has received two extensions from FERC since the issuance of the license amendment. The latest extension, granted by FERC in May 2014, allows Idaho Power until July 2022 to complete the project. Construction associated with renovations at the intake structure, the new scenic flow structure, and the replacement of the gated spillway at Shoshone Falls commenced in 2014 and is scheduled to be completed in December 2015. Idaho Power continues to analyze the costs and benefits of the generator/turbine expansion segment of the project.

For the 2015 IRP, Idaho Power is considering the Shoshone Falls generator/turbine expansion a resource option. The expansion is expected to produce on average about 200 GWh annually of incremental energy above the existing power plant configuration, with nearly 75 percent of the incremental energy occurring during the January through June period. The incremental energy is assumed to be REC eligible. A cost-benefit analysis of the generator/turbine expansion is provided in Chapter 9.

Wind

A typical wind project consists of an array of wind turbines ranging in size from 1 to 3 MW each. The majority of 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.

When compared to other renewable options, wind resources are well suited for the Pacific Northwest and Intermountain regions, as evidenced by the number of existing projects. Wind resources present a problem for utilities due to the variable and intermittent nature of wind generation. Therefore, planning new wind resources requires estimates of the expected annual energy and peak-hour capacity. For the 2015 IRP, Idaho Power used an annual average capacity factor of 28 percent and a capacity factor of 5 percent for peak-hour planning. The capital-cost estimate used in the IRP for wind resources is $1,800 per kW, and the 25-year levelized cost of energy is $135 per MWh, which includes a wind integration cost of $15.39 per MWh.

Biomass

Biomass resource types considered in the 2015 IRP include wood-burning resources and anaerobic digesters. Wood burning resources typically rely on a steady supply of woody residue collected from forested areas. Therefore, fuel supply can be an issue for these types of plants as the radius of the area used to collect fuel is expanded. Several anaerobic digesters have been built in southern Idaho due to the size of the dairy industry and the quantity of fuel available. However, these digesters are limited in size and would be difficult to develop on a utility scale.

The capital-cost estimate used in the IRP for a 35-MW wood-burning biomass project is $2,622 per kW, and $4,761 per kW for a 3-MW anaerobic digester project. The wood-burning unit is expected to have an annual capacity factor of 85 percent, while the anaerobic digester is expected to operate at 75 percent. Based on the annual capacity factors, the 30-year levelized cost of production is $102 per MWh for the wood-burning unit and $119 per MWh for the anaerobic digester.

Conventional Resources

While much attention has been paid to renewable resources over the past few years, conventional generation resources continue to be needed to provide dispatchable capacity, which is critical in maintaining the reliability of an electrical system. These conventional generation technologies include natural gas-fired resources, nuclear, and coal.

Natural Gas-Fired Resources

Natural gas-fired resources burn natural gas in a combustion turbine to generate electricity. CCCTs are typically used for baseload energy, while less-efficient SCCT are used to generate electricity during peak-load periods. Additional details on the characteristics of both types of natural gas resources are presented in the following sections.

CCCT and SCCT resources are typically sited near existing gas pipelines, which is the case for Idaho Power's existing gas resources. However, the capacity of the existing gas pipeline system is almost fully allocated. Therefore, the 2015 IRP assumes new natural gas resources would require building additional pipeline capacity. This additional cost is accounted for in portfolios containing new gas resources and not in the resource stack cost estimate for CCCTs or SCCTs.

Combined-Cycle Combustion Turbines

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, offers significant operating flexibility, and emits fewer emissions when compared to coal, therefore requiring fewer pollution controls.

A traditional CCCT plant consists of a gas turbine/generator equipped with a heat recovery steam generator (HRSG) to capture waste heat from the turbine exhaust. The HRSG uses waste heat from the combustion turbine to drive 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 an SCCT. New CCCT plants can be built or existing SCCT plants can be converted to combined-cycle units by adding an HRSG.

Several CCCT plants, similar to Idaho Power's Langley Gulch project, are planned in the region due to recently declining natural gas prices, the need for baseload energy, and additional operating reserves needed to integrate wind resources. While there is no current shortage of natural gas, fuel supply is a critical component of the long-term operation of a CCCT. The capital-cost estimate used in the IRP for a CCCT resource is $1,145 per kW, and the 30-year levelized cost of production at a 70-percent annual capacity factor is $79 per MWh.

Simple-Cycle Combustion Turbines

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

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. High electricity prices combined with persistent drought conditions during 2000–2001, 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 430 MW of SCCT capacity. As peak summertime electricity demand continues to grow within Idaho Power's service area, SCCT generating resources remain a viable option to meet peak load during 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.

The 2015 IRP evaluated two SCCT technologies: 1) a 47-MW small, aeroderivative unit and 2) a 170-MW industrial-frame unit. The capital-cost estimate used in the IRP for the small, aeroderivative unit is $1,000 per kW, and an industrial-frame unit is $800 per kW. Both the aeroderivative unit and the industrial-frame unit are expected to have an annual capacity factor of 10 percent.

Based on the annual capacity factor, the 35-year levelized cost of production is $250 per MWh for the small, aeroderivative unit and $219 per MWh for the industrial-frame unit. These levelized costs are close to the same as the higher efficiency of the small aeroderivative unit offsets the slightly higher capital cost. If needed, Idaho Power would evaluate these two technologies in greater detail prior to issuing a request for proposal (RFP) to determine which technology would provide the greatest benefit.

Reciprocating Engines

Reciprocating engine generation sets are typically natural gas-fired engines connected to a generator through a flywheel and coupling. Because they are mounted on a common baseframe, the entire unit can be assembled, tuned, and tested in the factory before being delivered to the power plant location, which minimizes capital costs. Operationally, reciprocating engines are typically installed in configurations with multiple, identical units, which allows each unit to run at its best efficiency point once started. As more generation is needed, additional units are started. This configuration also allows for relatively inexpensive future expansion of the plant capacity.

For the IRP, Idaho Power modeled a reciprocating engine similar to the 34SG model manufactured by Wärtsilä with a nameplate rating of 18.8 MW. The capital-cost estimate used for a reciprocating engine resource is $500 per kW, and the 40-year levelized cost of production at a 10-percent annual capacity factor is $136 per MWh.

Combined Heat and Power

Combined heat and power (CHP), or cogeneration, typically refers to simultaneous production of both electricity and useful heat from a single plant. CHP plants are typically located at, or near, commercial or industrial facilities capable of using the heat generated in the process. These facilities are sometimes referred to as a steam host. Generation technologies frequently used in CHP projects are gas turbines or engines with a heat-recovery unit.

The main advantage of CHP is that higher overall efficiencies can be obtained because the steam host is able to use a large portion of the waste heat that would otherwise be lost in a typical generation process. Because CHP resources are typically located near load centers, building additional transmission capacity can also often be avoided. In addition, reduced costs

for the steam host provide a competitive advantage that would ultimately help the local economy.

In the evaluation of CHP resources, it became evident that CHP could be a relatively high-cost addition to Idaho Power's resource portfolio if the steam host's need for steam forced the electrical portion of the project to run at times when electricity market prices were below the dispatch cost of the plant. To find ways to make CHP more economical, Idaho Power is committed to working with individual customers to design operating schemes that allow power to be produced when it is most valuable, while still meeting the needs of the steam host's production process. This would be difficult to model for the IRP because each potential CHP opportunity could be substantially different.

Recognizing the actual cost of a CHP resource may vary depending on the specific facility being considered, the capital-cost estimate used in the IRP for CHP is $2,123 per kW, and the 40-year levelized cost of production evaluated at an annual capacity factor of 80 percent is $81 per MWh.

Nuclear Resources

The nuclear power industry has been working to develop and improve reactor technology for some time, and Idaho Power has continued to evaluate various technologies in the IRP. Due to the Idaho National Laboratory (INL) site in eastern Idaho, the IRP has typically assumed that an advanced-design or small modular reactor could be built on the site. For the 2015 IRP, high capital costs coupled with a great amount of uncertainty in waste disposal issues prevented a nuclear resource from being included in the portfolio analysis. In addition, the recent earthquake and tsunami in Japan, and the impact on the Fukushima nuclear plant, created a global concern over the safety of nuclear power generation. While there have been new design and safety measures implemented, it is difficult to know the full impact this disaster will have on the future of nuclear power generation.

For the 2015 IRP, a 1,100-MW advanced nuclear resource and a 600-MW small modular plant were analyzed; however, for both types of plants, it was assumed that Idaho Power would only be a part owner in either type of facility by taking 250 MW of the total plant capacity. The capital-cost estimate used in the IRP for an advanced nuclear resource is $4,350 per kW, and the 40-year levelized cost of production, evaluated at an annual capacity factor of 90 percent, is $119 per MWh. For the small modular reactor technology, the capital-cost estimate is $5,000 per kW, and the 40-year levelized cost of production, evaluated at an annual capacity factor of 95 percent, is $343 per MWh.

Coal Resources

Conventional coal resources have been a part of Idaho Power's generation portfolio since the early 1970s. Growing concerns over global warming and climate change have made it impractical to consider building any new conventional coal resources; however, integrated gasification combined cycle (IGCC) and IGCC coupled with carbon sequestration are two technologies that were still evaluated in the IRP.

IGCC is an evolving coal-based technology designed to substantially reduce CO_2 emissions. As the regulation of CO_2 emissions eventually makes conventional coal resources obsolete, the commercialization of this technology may allow the continued use of the country's coal resources. IGCC technology is also dependent on the development of carbon capture and sequestration technology that would allow CO_2 to be stored underground for long periods of time.

Coal gasification is a relatively mature technology, but it has not been widely adapted as a resource to generate electricity. IGCC technology involves turning coal into a synthetic gas or "syngas" that can be processed and cleaned to a point that it meets pipeline quality standards. To produce electricity, the syngas is burned in a conventional combustion turbine that drives a generator.

The addition of CO_2-capture equipment decreases the overall efficiency of an IGCC plant by as much as 15 percent. In addition, once the carbon is captured, it must either be used or stored for long periods of time. CO_2 has been injected into existing oil fields to enhance oil recovery; however, if IGCC technology were widely adopted by utilities for power production, the quantities of CO_2 produced would require the development of underground sequestration methods.

Carbon sequestration involves taking captured CO_2 and storing it away from the atmosphere by compressing and pumping it into underground geologic formations. If compression and pumping costs are charged to the plant, the overall efficiency of the plant is reduced by an additional 15 to 20 percent. Sequestration methods are currently being developed and tested; however, commercialization of the technology is not expected to happen for some time. The capital-cost estimate used in the IRP for IGCC is $3,257 per kW, and the 35-year levelized cost of production, evaluated at an annual capacity factor of 85 percent, is $116 per MWh. The capital-cost estimate used for IGCC with carbon sequestration is $6,390 per kW, and the 35-year levelized cost of production, evaluated at an annual capacity factor of 75 percent, is $184 per MWh.

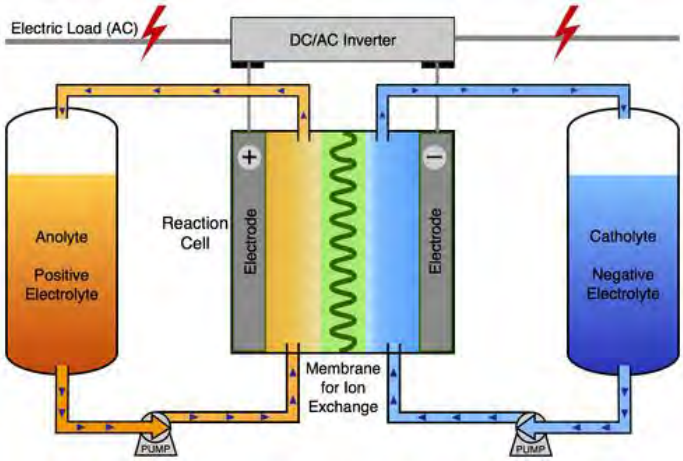
Storage Technologies

RPSs have spurred the development of renewable resources in the Pacific Northwest to the point where there is an oversupply of energy. Recently, Mid-Columbia wholesale market prices for electricity are typically one-third to one-half lower than just a few years ago. At the same time, retail rates for electricity continue to grow as utilities have to pass the cost of building these resources on to customers. The oversupply issue has grown to the point where at certain times of the year, such as in the spring, low customer demand coupled with large amounts of hydro and wind generation cause real-time and day-ahead wholesale market prices to go negative.

As more intermittent renewable resources like wind and solar continue to be built within the region, the need for energy storage is amplified. While there are many storage technologies at various stages of development, such as hydrogen storage, compressed air, and flywheels, the 2015 IRP considered and evaluated three specific storage technologies: 1) battery storage, 2) ice-based TES, and 3) pumped storage.

Battery Storage

Just as there are many types of storage technologies being researched and developed, there are numerous types of battery storage technologies at various stages of development. The 2015 IRP focused on one specific type of battery technology; the vanadium redox-flow battery (VRB).



Basic illustration of a flow battery.[7]

Advantages of the VRB technology include its low cost, long life, and easy scalability to utility/grid applications. Most battery technologies are not a good fit for utility-scale applications because they cannot be easily or economically scaled to much larger sizes. The VRB overcomes much of this issue because the capacity of the battery can be increased just by increasing the size of the tanks that contain the electrolytes, which also helps keep the cost relatively low.

VRB technology also has an advantage in maintenance and replacement costs, as only certain components need replaced about every 10 years, whereas other battery technologies require a complete replacement of the battery and more frequently depending on how they are used. For the IRP, the capital-cost estimate for the VRB is $3,000 per kW, and the 10-year levelized cost of production, evaluated at an annual capacity factor of 25 percent, is $240 per MWh.

Ice-Based Thermal Energy Storage

Ice-based TES is a concept developed to take advantage of the A/C needs of mid-sized to large commercial buildings. The general concept is to create ice during low-load/low-price times (light load hours), then to use the ice for A/C needs during the high-load/higher-price times (heavy load hours). While this concept does not specifically store electricity, it does shift the time the energy is consumed, with the overall goal of reducing peak daytime demand.

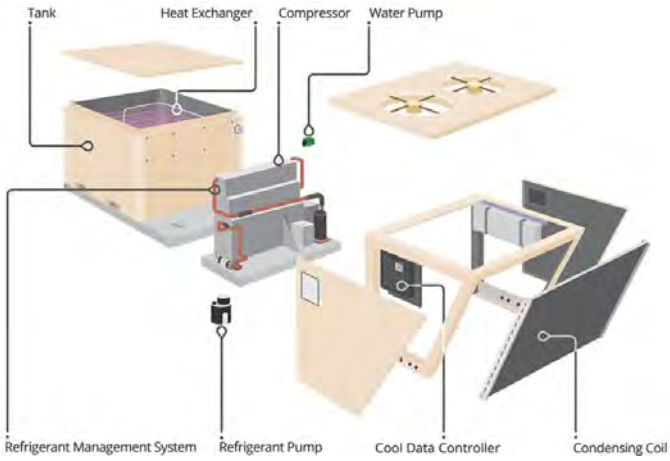


Illustration of an ice-based TES system.[8]

[7] Source: http://strategy.sauder.ubc.ca/antweiler/blog.php?item=2014-09-28.

[8] Source: http://www.ice-energy.com/technology/ice-bear-energy-storage-system.

One company currently commercializing the ice-based TES technology is Ice Energy with their *Ice Bear Energy Storage System*. Requirements in California to develop energy storage have allowed several utilities to begin installing and testing this technology, with several installations of 5 MW to 15 MW in size. For the IRP, the capital-cost estimate used for this technology is $1,500 per kW, and the 20-year levelized cost of production, evaluated at an annual capacity factor of 10.4 percent, is $224 per MWh.

Pumped Storage

Pumped storage is a type of hydroelectric power generation used to change the "shape" or timing when electricity is produced. The technology stores energy in the form of water, pumped from a lower elevation reservoir to a higher elevation. Lower-cost, off-peak electricity is used to pump water from the lower reservoir to the upper reservoir. During higher-cost periods of high electrical demand, the water stored in the upper reservoir is used to produce electricity.

Pumped-storage facility.[9]

For pumped storage to be economical, there must be a significant differential in the price of electricity between peak and off-peak times to overcome the costs incurred due to efficiency and other losses that make pumped storage a net consumer of energy overall. Historically, the differential between peak and off-peak energy prices in the Pacific Northwest has not been sufficient to make pumped storage an economically viable resource; however, with the recent increase in the number of wind projects, the amount of intermittent generation provided, and the ancillary services required, this may change. The capital-cost estimate used in the IRP for pumped storage is $5,000 per kW, and the 50-year levelized cost of production is $346 per MWh.

[9] Source: http://www.renewableenergyworld.com/rea/news/article/2010/10/worldwide-pumped-storage-activity.

This page left blank intentionally.

6. Transmission Planning

Past and Present Transmission

Idaho Power's double-circuit 230-kilovolt (kV) transmission line traversing Hells Canyon.

High-voltage transmission lines are vital to the development of energy resources to serve Idaho Power customers. Transmission lines have facilitated the development of southern Idaho's network of hydroelectric projects that serve the electric customers of southern Idaho and eastern Oregon. Regional transmission lines that stretch from the Pacific Northwest to the HCC and to the Treasure Valley were central to the development of the HCC projects in the 1950s and 1960s. In the 1970s and 1980s, transmission lines were instrumental in the development of partnerships in the three coal-fired power plants located in neighboring states that supply approximately one-third of the energy consumed by Idaho Power customers. Finally, transmission lines allow Idaho Power to economically balance the variability of its hydroelectric and intermittent resources with access to wholesale energy markets.

Idaho Power's regional transmission interconnections improve reliability by providing the flexibility to move electricity between utilities and also provide economic benefits based on the ability to share operating reserves. Historically, Idaho Power has been a summer peaking utility, while most other utilities in the Pacific Northwest experience system peak loads during the winter. Because of the difference in peak seasons, Idaho Power purchases energy from the Mid-Columbia energy trading market to meet peak summer load, and Idaho Power sells excess energy to Pacific Northwest utilities during the winter and spring. New regional transmission connections to the Pacific Northwest will benefit the environment and Idaho Power customers through the following:

- The construction of additional peaking resources to serve summer peak load is delayed or avoided.
- Revenue from off-system sales during the winter and spring is credited to customers through the PCA.
- Revenue from others' use of the transmission system is credited to Idaho Power customers.
- System reliability is increased.
- Capacity is added to help integrate intermittent resources, such as wind and solar.
- Flexibility is provided to respond to the proposed CAA Section 111(d) requirements.
- The ability to more efficiently implement advanced market tools, such as EIMs or SCED.

Transmission Planning Process

In recent years, FERC mandated several aspects of the transmission planning process. FERC Order No. 1000 requires Idaho Power to participate in transmission planning on a local, regional, and interregional basis, as described in Attachment K of the Idaho Power Open-Access Transmission Tariff (OATT) and summarized in the following sections.

Local Transmission Planning Process

The expansion planning of Idaho Power's transmission network occurs through a local-area transmission advisory process and the biennial local transmission planning process.

Local-Area Transmission Advisory Process

Idaho Power develops long-term, local-area transmission plans with community advisory committees. The community advisory committees consist of jurisdictional planners; mayors; council members; commissioners; and large industry, commercial, residential, and environmental representatives. The plans identify the transmission and substation infrastructure required for the full development of the area. The plans account for land-use limits and other resources of the local area. The plans identify the approximate year a project will be placed in service. Local-area plans have been created for the following five load centers in southern Idaho:

1. Eastern Idaho
2. Magic Valley
3. Wood River Valley
4. Treasure Valley
5. West Central Mountains

Recently, the *Treasure Valley Electric Plan* was divided into two plans:

1. *Western Treasure Valley Electrical Plan*—The western plan was completed in 2011 and encompasses Malheur County in Oregon and Canyon, Gem, Owyhee, Payette, and Washington counties in Idaho.
2. *Eastern Treasure Valley Electric Plan*—The eastern plan was completed in 2012 and encompasses all or portions of Ada, Elmore, and Owyhee counties in Idaho.

Biennial Local Transmission Planning Process

The biennial local transmission plan (LTP) identifies the transmission required to interconnect the load centers, integrate planned generation resources, and incorporate regional transmission plans. The LTP is a 20-year plan that incorporates the planned supply-side resources identified in the IRP process, the transmission upgrades identified in the local-area transmission advisory process, the forecasted network customer load (e.g., Bonneville Power Administration [BPA] customers in eastern Oregon and southern Idaho), Idaho Power's retail customer load, and third-party transmission customer requirements. By identifying potential resources,

potential resource locations, and load-center growth, the required transmission system capacity expansions are identified to safely and reliably provide service to customers. The LTP is shared with the regional transmission planning process.

Regional Transmission Planning

Idaho Power is active in regional transmission planning through the Northern Tier Transmission Group (NTTG). The NTTG was formed in early 2007 to improve the operation and expansion of the high-voltage transmission system that delivers power to consumers in seven western states. In addition to Idaho Power, other members include Deseret Power Electric Cooperative, NorthWestern Energy, PGE, PacifiCorp (Rocky Mountain Power and Pacific Power), and the Utah Associated Municipal Power Systems (UAMPS). Biennially, the NTTG develops a regional transmission plan using a public stakeholder process to evaluate transmission needs resulting from members' load forecasts, LTPs, IRPs, generation interconnection queues, other proposed resource development, and forecast uses of the transmission system by wholesale transmission customers.

Interconnection-Wide Transmission Planning

The WECC Transmission Expansion Planning Policy Committee (TEPPC) serves as the interconnection-wide transmission planning facilitator in the western US. Specifically, the TEPPC has three functions:

1. Oversee data management for the western interconnection.
2. Provide policy and management of the planning process.
3. Guide the analyses and modeling for Western Interconnection economic transmission expansion planning.

In addition to providing the means to model the transmission implications of various load and resource scenarios at an interconnection-wide level, the TEPPC coordinates planning between transmission owners, transmission operators, and regional planning entities.

The WECC Planning Coordination Committee manages additional transmission planning and reliability-related activities on behalf of electric-industry entities in the West. WECC activities include resource adequacy analyses and corresponding North American Electric Reliability Corporation (NERC) reporting, transmission security studies, and the transmission line rating process.

Existing Transmission System

Idaho Power's transmission system extends from eastern Oregon through southern Idaho to western Wyoming and is composed of 115-, 138-, 161-, 230-, 345-, and 500-kV transmission facilities. The sets of lines that transmit power from one geographic area to another are known as transmission paths. There are defined transmission paths to other states and between the southern Idaho load centers mentioned previously in this chapter. Idaho Power's transmission system and paths are shown in Figure 6.1.

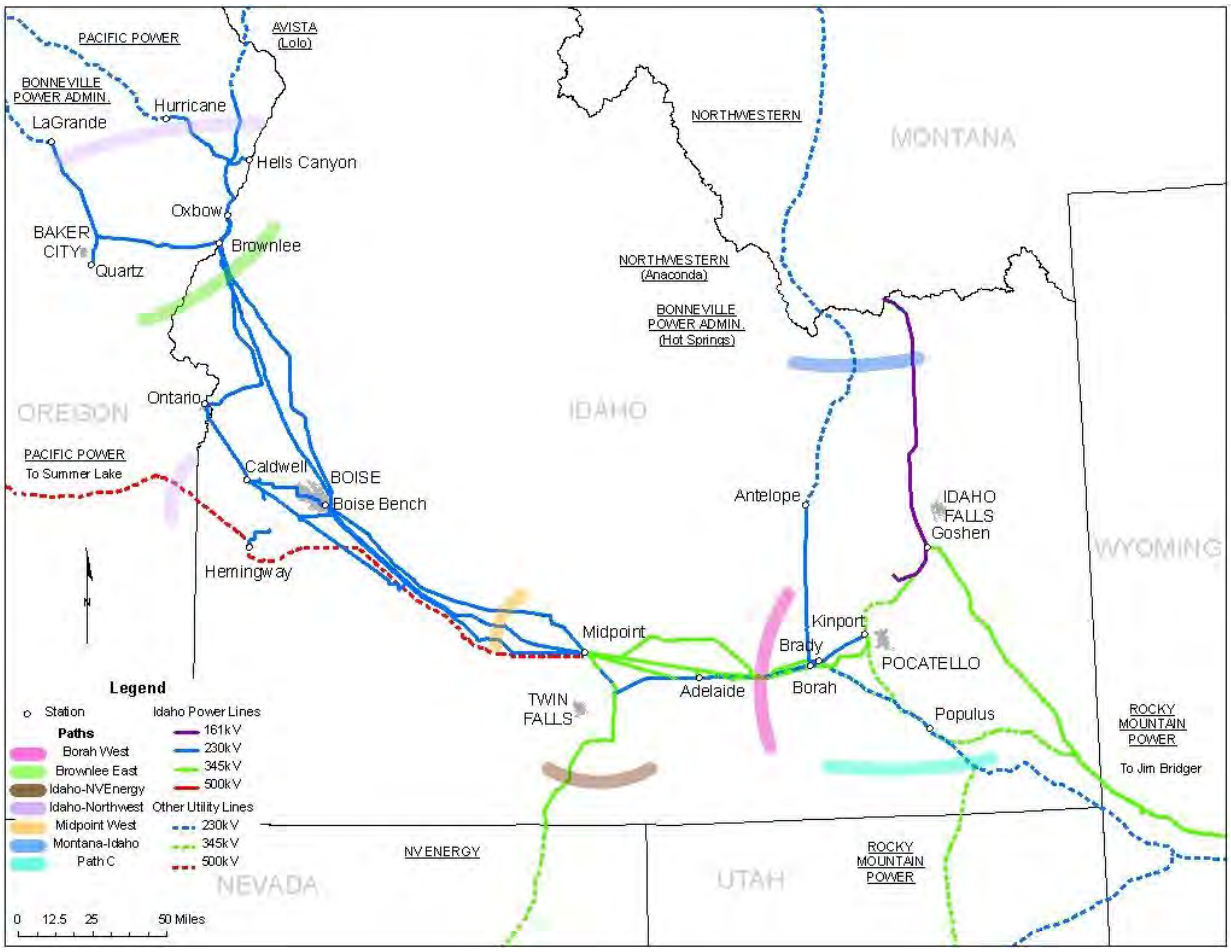


Figure 6.1 Idaho Power transmission system map

The transmission paths identified on the map are described in the following sections, along with the conditions that result in capacity limitations.

Idaho–Northwest Path

The Idaho–Northwest transmission path consists of the 500-kV Hemingway–Summer Lake line, the three 230-kV lines between the HCC and the Pacific Northwest, and the 115-kV interconnection at Harney Substation near Burns, Oregon. The Idaho–Northwest path is capacity-limited during summer months due to transmission-wheeling obligations for the BPA eastern Oregon and southern Idaho load and due to energy imports from the Pacific Northwest to serve Idaho Power retail load. To access new resources, including market purchases, located west of the path, additional transmission capacity will be required to deliver the energy to Idaho Power's service area.

Brownlee East Path

The Brownlee East transmission path is on the east side of the Idaho–Northwest Interconnection shown in Figure 6.1. Brownlee East is comprised of the 230-kV and 138-kV lines east of the HCC and Quartz Substation near Baker City, Oregon. When the Hemingway–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 capacity limitation on the Brownlee East transmission path occurs between Brownlee and the Treasure Valley.

The Brownlee East path is capacity-limited during the summer months due to a combination of HCC hydroelectric generation flowing east into the Treasure Valley concurrent with transmission-wheeling obligations for BPA southern Idaho load and Idaho Power energy imports from the Pacific Northwest. Capacity limitations on the Brownlee East path limit the amount of energy Idaho Power can import from the HCC as well as off-system purchases from the Pacific Northwest. If new resources, including market purchases, are located west of the path, additional transmission capacity will be required to deliver the energy to the Treasure Valley load center.

Idaho–Montana Path

The Idaho–Montana transmission path consists of the Antelope–Anaconda 230-kV and Goshen–Dillon 161-kV transmission lines. The Idaho–Montana path is also capacity-limited during the summer months as Idaho Power, BPA, PacifiCorp, and others move energy south from Montana into Idaho.

Borah West Path

The Borah West transmission path is internal to the Idaho Power system. The path is comprised of 345-kV, 230-kV, and 138-kV transmission lines west of the Borah substation located near American Falls, Idaho. Idaho Power's one-third share of energy from the Jim Bridger plant flows over this path, as well as east-side hydroelectric energy and energy imports from Montana, Wyoming, and Utah. PacifiCorp's two-thirds share of energy from the Jim Bridger plant also flows across this path to load centers in the Pacific Northwest. The Borah West path is capacity-limited during summer months due to transmission-wheeling obligations coinciding with high eastern thermal and wind production. Heavy path flows are also likely to exist during the light-load hours of the fall and winter months as high eastern thermal and wind production move east to west across the system to the Pacific Northwest. Additional transmission capacity will likely be required if new resources or market purchases are located east of the Borah West path.

Midpoint West Path

The Midpoint West path is an internal path comprised of the 230-kV and 138-kV transmission lines west of Midpoint Substation located near Jerome, Idaho. The Midpoint West path is capacity-limited due to east-side Idaho Power resources, PURPA resources, and energy imports. Similar to the Borah West path, the heaviest path flows are likely to exist during the fall and winter when significant wind and thermal generation is present east of the path. Additional transmission capacity will likely be required if new resources or market purchases are located east of the Midpoint West path.

Idaho–Nevada Path

The Idaho–Nevada transmission path is comprised of the 345-kV Midpoint–Humboldt line. Idaho Power and NV Energy are co-owners of the line, which was developed at the same time the North Valmy Power Plant was built in northern Nevada. Idaho Power is allocated

100 percent of the northbound capacity, while NV Energy is allocated 100 percent of the southbound capacity. The available import, or northbound, capacity on the transmission path is fully subscribed with Idaho Power's share of the North Valmy generation plant.

Idaho–Wyoming Path

The Idaho–Wyoming path, referred to as Bridger West, is comprised of three 345-kV transmission lines between the Jim Bridger generation plant and southeastern Idaho. Idaho Power owns 774 MW of the 2,400-MW east-to-west capacity. PacifiCorp owns the remaining capacity. The Bridger West path effectively feeds into the Borah West path when power is moving east to west from Jim Bridger; consequently, the import capability of the Bridger West path is limited by Borah West path capacity constraints.

Idaho–Utah Path

The Idaho–Utah path, referred to as Path C, is comprised of 345-, 230-, 161-, and 138-kV transmission lines between southeastern Idaho and northern Utah. PacifiCorp is the path owner and operator of all of the transmission lines. The path effectively feeds into Idaho Power's Borah West path when power is moving from east to west; consequently, the import capability of Path C is limited by Borah West path capacity limitations.

Table 6.1 Available transmission import capacity

	Total Transmission Capacity*		
Transmission Path	**Import Direction**	**Capacity (MW)**	**ATC (MW)****
Idaho–Northwest	West to east	1,200	0
Idaho–Nevada	South to north	262	0
Idaho–Montana	North to south	383	0
Brownlee East	West to east	1,915	0
Midpoint West	East to west	1,027	0
Borah West	East to west	2,557	0
Idaho–Wyoming (Bridger West)	East to west	2,400	60
Idaho–Utah (Path C)	South to north	1,250	0***

*Total transmission capacity and available transmission capacity (ATC) as of April 1, 2015.

** The ATC of a specific path may change based on changes in the transmission service and generation interconnection request queue (i.e., the end of a transmission service, granting of transmission service, or cancelation of generation projects that have granted future transmission capacity).

***Idaho Power-estimated value; actual ATC managed by PacifiCorp.

Boardman to Hemingway

In the 2006 IRP process, Idaho Power identified the need for a transmission line to the Pacific Northwest electric market. At that time, a line interconnecting at the McNary Substation to the greater Boise area was included in IRP portfolios. Since its initial identification, the project has been refined and developed, including different terminus locations and sizing the project to economically meet projected demand. The project identified in 2006 has evolved into what is currently the B2H project. The project currently involves permitting, constructing, operating, and maintaining a new, single-circuit 500-kV transmission line approximately 300 miles long

between the proposed Longhorn Station in the Boardman, Oregon, area and the Hemingway Substation in southwest Idaho. The new line will provide many benefits, including the following:

- Greater access to the Pacific Northwest electric market to serve homes, farms, and businesses in Idaho Power's service area
- Improved system reliability and reduced capacity limitations on the regional transmission system as demands on the system continue to grow
- Assurance of Idaho Power's ability to meet customers' existing and future energy needs in Idaho and Oregon
- Flexibility to integrate renewable resources, respond to pending carbon legislation and more efficiently implement advanced market tools
- Flexibility to respond to the proposed CAA Section 111(d) requirements

The B2H project was identified as part of the preferred resource portfolio in Idaho Power's 2009, 2011, and 2013 IRPs.

In January 2012, Idaho Power entered into a joint funding agreement with PacifiCorp and BPA to pursue permitting of the project. The agreement designates Idaho Power as the permitting project manager for the B2H project. Table 6.2 shows each party's B2H capacity and permitting cost allocation.

Table 6.2 B2H capacity and permitting cost allocation

	Idaho Power	BPA	PacifiCorp
Capacity (MW) west to east	350 200 winter/500 summer	400 550 winter/250 summer	300
Capacity (MW) east to west	85	97	818
Permitting cost allocation	21%	24%	55%

Additionally, a Memorandum of Understanding (MOU) was executed between Idaho Power, BPA, and PacifiCorp to explore opportunities for BPA to establish eastern Idaho load service from the Hemingway Substation. BPA identified six solutions—including two B2H options—to meet its load-service obligations in southeast Idaho. On October 2, 2012, BPA publically announced the preferred solution to be the B2H project.

The permitting phase of the B2H project is subject to review and approval by, among other government entities, the Bureau of Land Management (BLM), the US Forest Service (USFS), and the Oregon Department of Energy (ODOE). The federal permitting process is dictated primarily by the *Federal Land Policy Management Act* and *National Forest Management Act* and is subject to NEPA review. The BLM is the lead agency in administering the NEPA process for the B2H project. On December 19, 2014, BLM published the Draft Environmental Impact Statement (Draft EIS). Figure 6.2 shows the proposed transmission line routes included in the Draft EIS with the agency preferred route. Idaho Power expects the BLM to issue a Final EIS in 2016.

In late February 2013, Idaho Power submitted the preliminary Application for Site Certificate (pASC) to the ODOE as part of the state siting process. Idaho Power intends to submit an amended pASC in late 2015 or 2016.

In light of the permitting delays and siting impediments that have occurred and may occur, Idaho Power is unable to accurately determine an approximate in-service date for the line but expects the in-service date would be in 2021 or beyond. Additional project information is available at boardmantohemingway.com.

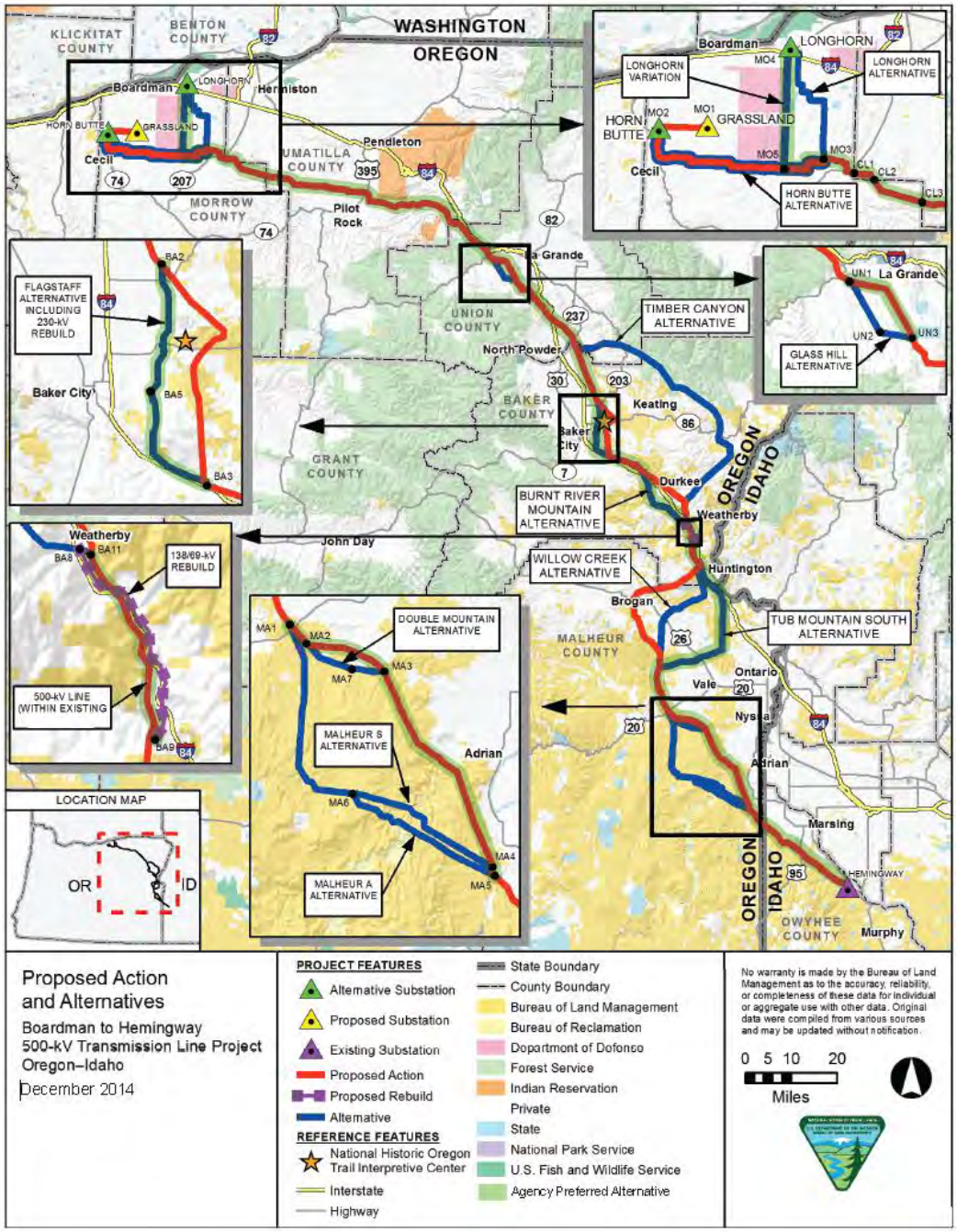


Figure 6.2 B2H routes with the agency-preferred alternative

Gateway West

The Gateway West transmission line project is a joint project between Idaho Power and Rocky Mountain Power to build and operate approximately 1,000 miles of new transmission lines from the planned Windstar Substation near Glenrock, Wyoming, to the Hemingway Substation near Melba, Idaho. Rocky Mountain Power has been designated the permitting project manager for Gateway West, with Idaho Power providing a supporting role.

Figure 6.3 shows a map of the project identifying the routes studied in the federal permitting process and depicts the BLM's preferred route. Idaho Power has a one-third interest in the segments between Midpoint and Hemingway, Cedar Hill and Hemingway, and Cedar Hill and Midpoint. Further, Idaho Power has sole interest in the segment between Borah and Midpoint (segment 6), which is an existing transmission line operated at 345-kV but constructed at 500-kV.

Figure 6.3 Gateway West Map

The Gateway West project will provide many benefits to Idaho Power customers, including the following:

1. Relieve Idaho Power's constrained transmission system between the Magic Valley area (Midpoint) and the Treasure Valley area (Hemingway). Transmission connecting the Magic Valley and Treasure Valley is part of Idaho Power's "core" transmission system, connecting two major Idaho Power load pockets.

2. Provide the option to locate future generation resources east of the Treasure Valley.

3. Provide future load-service capacity to the Magic Valley from the Cedar Hill Substation.

4. Transmission capability is needed to meet the transmission needs of the future, including transmission needs associated with intermittent resources.

Phase 1 of Gateway West is expected to provide up to 1,500 MW of additional transfer capacity between Midpoint and Hemingway. The fully completed project would provide a total of 3,000 MW of additional transfer capacity. Idaho Power has a one-third interest in these capacity additions.

The two transmission projects, B2H and Gateway West, are complementary and will provide an upgraded transmission path from the Pacific Northwest across Idaho and into eastern Wyoming with an additional transmission connection to the population center along the Wasatch Front in Utah.

Under the federal permitting process established by NEPA, the BLM has completed the EIS for all segments of the Gateway West project except segment 8 (Midpoint to Hemingway) and segment 9 (Cedar Hill to Hemingway). The BLM is conducting a supplemental environmental analysis on these two segments. A final record of decision for these two segments is expected by late 2016, subject to permitting completion.

More information about the Gateway West project can be found at gatewaywestproject.com.

Gateway West Need Analysis

Idaho Power has two internal transmission paths between the Magic Valley and Treasure Valley:

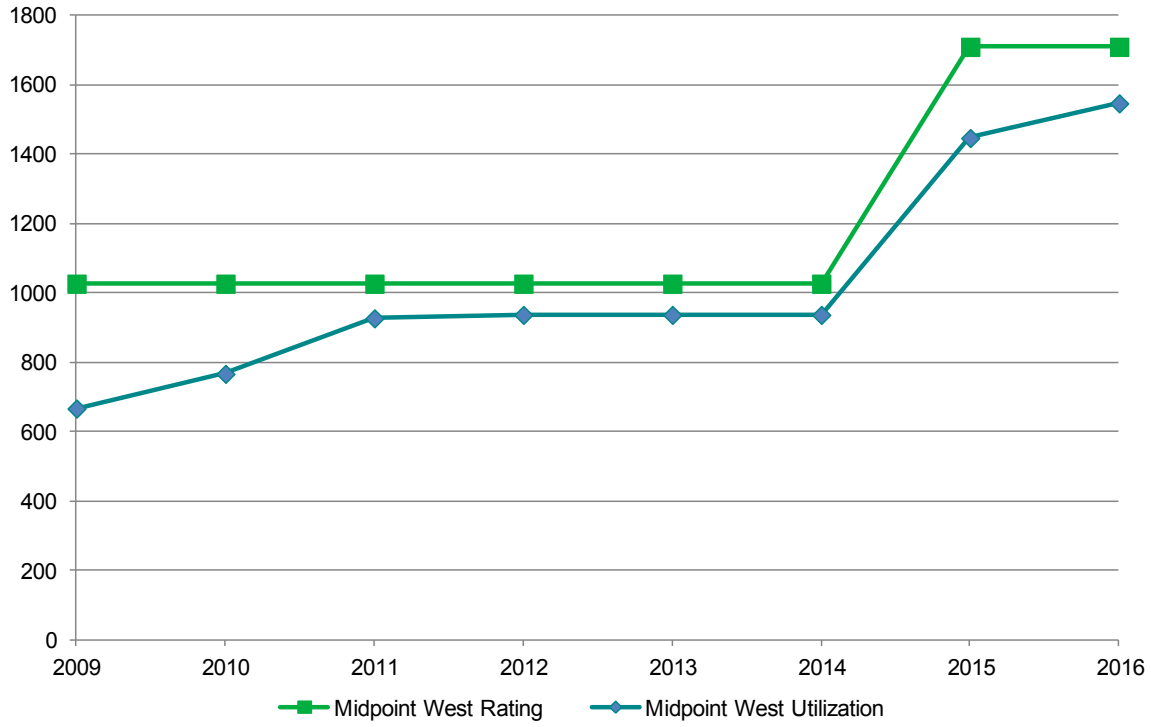
- Boise East
- Midpoint West

The Boise East transmission path consists of 230-kV, 138-kV and 69-kV transmission lines connecting the Mountain Home area to the Boise/Nampa/Caldwell area. This transmission path is currently being studied due to large amounts of solar generation proposed to be sited in and around the Mountain Home area. Gateway West will increase the capability of the Boise East path.

The Midpoint West transmission path consists of 230-kV and 138-kV transmission lines connecting the Magic Valley area to the Mountain Home area. The Midpoint West transmission path has a rating of 1,027 MW which will increase to 1,710 MW following two initiatives currently underway:

1. Idaho Power will expand the Midpoint West rating from 1,027 MW to 1,300 MW through incremental upgrades to existing transmission assets (230 kV and below). These upgrades are expected to be in service by the end of 2015.
2. Idaho Power has made arrangements to acquire an ownership share of the PacifiCorp-owned Midpoint–Hemingway 500-kV line, pending regulatory approval. Idaho Power's ownership share will equate to 410 MW of the 1,500-MW line rating. This is expected to be finalized by the end of 2015.

Over the past several years, Idaho Power's use of the Midpoint West transmission path has steadily increased. Figure 6.4 illustrates this increasing use.



Note: Large increases to the use of Midpoint West occurred in 2010 (PURPA Wind), 2011 (PURPA Wind), and 2015 (third-party transmission service). Use is also projected to increase in 2016 with the interconnection of 100 MW of solar in eastern Idaho.

Figure 6.4 Midpoint West Historical Utilization

The Midpoint West path will continue to be constrained following the upgrades described above. As the Boise East and Midpoint West paths become further used, Idaho Power will continue to invest in new transmission facilities to reinforce the transmission system. Gateway West is the planned upgrade that will increase the capability of the Midpoint West path.

Transmission Assumptions in the IRP Portfolios

Idaho Power makes resource location assumptions to determine transmission requirements as part of the IRP development process. Regardless of the location, supply-side resources included in the resource stack typically require local transmission improvements for integration into Idaho Power's system. Additional transmission improvement requirements depend on the location and size of the resource. The transmission assumptions and transmission upgrade requirements for incremental resources are summarized in Table 6.3.

The Hemingway Substation in southern Idaho is a major hub for power running through Idaho Power's transmission system.

Table 6.3 Transmission assumptions

Resource Type	Geographic Area	Resource Levels (incremental amounts)	Additional Transmission Requirements
B2H line	Hemingway Substation	500 MW (summer)/ 200 MW (winter)	New 230-kV line from Hemingway to the Treasure Valley.
Gas turbine (SCCT)	Elmore County	170 MW	New 230-kV substation and new 230-kV line to the Treasure Valley.
Gas turbine (CCCT)	Elmore County	300 MW	New 230-kV substation and new 230-kV line to the Treasure Valley.
CHP	Canyon County	45 MW	New 138-kV substation and new 138-kV line to existing 138-kV system.
Geothermal	Cassia County	30 MW	New 138-kV line from resource to existing 138-kV substation.
Reciprocating engines	Distributed	18 MW	No new transmission. New distribution upgrades assumed for each engine location.
PV	Elmore/Owyhee County	10 MW	New 138-kV substation and new 138-kV line to existing 138-kV system.
Pumped storage hydro	Above Brownlee Reservoir	300 MW	New 230-kV line from Oxbow to Treasure Valley, new 138-kV tap from site to existing 138-kV system.

The assumptions about the geographic area where particular supply-side resources are developed determine the transmission upgrades required.

7. Planning Period Forecasts

The IRP process requires Idaho Power to prepare numerous forecasts and estimates, which can be grouped into four main categories:

1. Load forecasts
2. Generation forecast for existing resources
3. Natural gas price forecast
4. Resource cost estimates

Forecasting load growth is essential for Idaho Power to meet future needs of customers.

The load and generation forecasts—including supply-side resources, DSM, and transmission import capability—are used to estimate surplus and deficit positions in the load and resource balance. The identified deficits are used to develop resource portfolios evaluated using financial tools and forecasts. The following sections provide details on the forecasts prepared as part of the 2015 IRP.

Load Forecast

Historically, Idaho Power has been a summer peaking utility with peak loads driven by irrigation pumps and A/C in June, July, and August. For a number of years, the growth rate of the summertime peak-hour load has exceeded the growth of the average monthly load. However, both measures are important in planning future resources and are part of the load forecast prepared for the 2015 IRP.

The expected case (median) load forecasts for peak-hour and average energy represent Idaho Power's most probable outcome for load growth during the planning period. However, the actual path of future retail electricity sales will not precisely follow the path suggested by the expected case forecast. Therefore, Idaho Power prepared two additional load forecasts that address the load variability associated with abnormal weather. The 70th-percentile and 90th-percentile load forecasts were developed to assist Idaho Power in reviewing the resource requirements that would result from higher loads due to adverse weather conditions.

Idaho Power prepares a sales and load forecast each year as part of the company's annual financial forecast. The sales forecast is heavily influenced by the most recent economic forecast of national and regional economic activity developed by Moody's Analytics, Inc., a national econometric consulting firm. Moody's Analytics, Inc., July 2014 macroeconomic forecast strongly influenced the 2015 IRP load forecast results. The national, state, metropolitan statistical area (MSA) and county economic projections are tailored to Idaho Power's service area using an in-house economic database. Specific demographic projections are also developed for the service area from national and local census data. National economic drivers from Moody's Analytics, Inc., are also used in developing the 2015 IRP load forecast. The forecasts of

households, population, employment, output, and retail electricity prices, along with historical customer consumption patterns, are used to develop customer forecasts and load projections.

Weather Effects

The expected-case load forecast assumes median temperatures and median precipitation, which means there is a 50-percent chance 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 loads can vary significantly depending on weather conditions, two alternative scenarios were analyzed to address load variability due to weather—70th-percentile and 90th-percentile load forecasts. Seventieth percentile weather means that in 7 out of 10 years, load is expected to be less than forecast, and in 3 out of 10 years, load is expected to exceed the forecast. Ninetieth percentile load has a similar definition with a 1-in-10 likelihood the load will be greater than the forecast.

Weather conditions are the primary factor affecting the load forecast on a monthly or seasonal basis. Over the longer-term, economic conditions, demographic conditions, and changing technologies influence the load forecast.

Economic Effects

The national recession that began in 2008 affected the local economy and energy use in Idaho Power's service area. The severity of the recession resulted in a decline in new customer growth. Idaho Power added less than 2,500 new residential customers in 2011. Recently, the number of new residential customers added each year has increased to over 6,500.

Likewise, overall system sales declined by 3.8 percent in 2009, followed by a 0.9-percent decline in 2010 and a slight decline in 2011. The 2009 through 2011 time period was the first time overall energy use had declined since the energy crisis of 2000 to 2001. In 2012, 2013, and 2014, system electricity sales increased by 1.7 percent, 0.5 percent, and 1.0 percent, respectively. The sales increases were due to economic recovery in the service area and higher irrigation sales.

The population in Idaho Power's service area, due to migration to Idaho from other states, is expected to increase throughout the planning period, and the population increase is included in the load forecast models. Idaho Power also continues to receive requests from prospective large-load customers attracted to southern Idaho due to the positive business climate and relatively low electric rates. In addition, the economic conditions in surrounding states may encourage some manufacturers to consider moving operations to Idaho.

The number of residential customers in Idaho Power's service area is expected to increase 1.6 percent annually from 428,000 at the end of 2014 to nearly 591,000 by the end of the planning period in 2034. Growth in the number of customers within Idaho Power's service area, combined with an expected declining consumption per customer, results in a 1.3-percent average residential load-growth rate.

The expected-case load forecast represents the most probable projection of load growth during the planning period. The forecast for system 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 annual average system load growth of 1.2 percent (over the period

2015 through 2034) is comprised of a residential load growth of 1.3 percent, a commercial load growth of 1.0 percent, an irrigation load growth of 0.5 percent, an industrial load growth of 2.0 percent, and an additional firm load growth of 0.6 percent.

The 2015 IRP average annual system load forecast reflects the continued improvement in the service-area economy. While economic conditions during the development of the 2013 IRP were positive, they were less optimistic than the actual performance experienced in the interim period leading up to the 2015 IRP. The improved economic and demographic variables driving the 2015 forecast are reflected by a more positive sales outlook throughout the planning period. The stalled recovery in the national and, to a lesser extent, service area economy caused load growth to stall through 2011. However, in 2012, the recovery was evident, with strength exhibited in most all economic time series. Retail electricity price projections for the 2015 IRP are lower relative to the 2013 IRP, serving to increase the forecast of average loads, especially in the second 10 years of the forecast period.

Significant factors and considerations that influenced the outcome of the 2015 IRP load forecast include the following:

- The load forecast used for the 2015 IRP reflects a near-term recovery in the service-area economy following a severe recession in 2008 and 2009 that kept sales from growing through 2011. The collapse in the housing sector in 2008 and 2009 dramatically slowed the growth of new households and, consequently, the number of residential customers being added to Idaho Power's service area. However, since 2011, residential and commercial customer growth along with housing and industrial activity, have shown signs of a meaningful and sustainable recovery. By 2017, customer additions are forecast to approach the growth that occurred prior to the housing bubble (2000–2004).

- The electricity price forecast used to prepare the sales and load forecast in the 2015 IRP reflects the additional plant investment and variable costs of integrating the resources identified in the 2013 IRP preferred portfolio, including the expected costs of carbon emissions assumed for the 2013 IRP. When compared to the electricity price forecast used to prepare the 2013 IRP sales and load forecast, the 2015 IRP price forecast yields lower future prices. The retail prices are most evident in the second 10 years of the planning period and impact the sales forecast positively, a consequence of the inverse relationship between electricity prices and electricity demand.

- There continues to be significant uncertainty associated with the industrial and special-contract sales forecasts due to the number of parties that contact Idaho Power expressing interest in locating operations within Idaho Power's service area, typically with an unknown magnitude of the energy and peak-demand requirements. The current sales and load forecast reflects only those commercial or industrial customers that have made a sufficient and significant investment indicating a commitment of the highest probability of locating in the service area. Therefore, the large numbers of businesses that have contacted Idaho Power and shown interest but have not made sufficient commitments are not included in the current sales and load forecast.

- Conservation impacts, including DSM energy efficiency programs and codes and standards, are considered and integrated into the sales forecast. Impacts of demand

response programs (on peak) are accounted for in the load and resource balance analysis within supply-side planning. The amount of committed and implemented DSM programs for each month of the planning period is shown in the load and resource balance in *Appendix C—Technical Appendix*.

- The 2015 irrigation sales forecast is higher than the 2013 IRP forecast throughout the entire forecast period due to the significant growth in the dairy industry, higher commodity prices, and changing crop-planting patterns. Following the dairy industry growth, there has been a trend toward more water-intensive crops, primarily alfalfa and corn. Farmers have also taken advantage of the commodities market by planting increasing levels of acreage. Additionally, the conversion of flood/furrow irrigation to sprinkler irrigation, primarily related to farmers trying to reduce labor costs, explains most of the increased energy consumption in recent years.

- Updated loss factors were determined by Idaho Power's Customer Operations Planning department. The annual average energy loss coefficients are multiplied by the calendar-month load, yielding the system load, including losses. A system loss study of 2012 was completed in May 2014. The results of the study concluded that, on average, the loss coefficients are lower than those used in the 2013 IRP. This resulted in a permanent reduction of nearly 20 aMW to the load forecast annually.

Peak-Hour Load Forecast

The system peak-hour load forecast includes the sum of the individual coincident peak demands of residential, commercial, industrial, and irrigation customers, as well as special contracts. Idaho Power uses the 95th-percentile forecast as the basis for peak-hour planning in the IRP. The 95th-percentile forecast is based on the 95th-percentile average peak-day temperature to forecast monthly peak-hour load.

Idaho Power's system peak-hour load record—3,407 MW—was recorded on July 2, 2013, at 4:00 p.m. The previous summer peak demand record was 3,245 MW on July 12, 2012, at 4:00 p.m. Summertime peak-hour load growth accelerated in the previous decade as A/C became standard in nearly all new residential home construction and new commercial buildings. System peak demand slowed considerably in 2009, 2010, and 2011, the consequences of a severe recession that brought new home and new business construction to a standstill. Demand response programs operating in the summertime have also had a significant effect on reducing peak demand. The 2015 IRP load forecast projects peak-hour load to grow by approximately 63 MW per year throughout the planning period. The peak-hour load forecast does not reflect the company's demand response programs, which are accounted for in the load and resource balance as a supply-side resource.

Figure 7.1 and Table 7.1 summarize three forecast outcomes of Idaho Power's estimated annual system peak load—median, 90th percentile, and 95th percentile. The 95th-percentile forecast uses the 95th-percentile peak-day average temperature to determine monthly peak-hour demand and serves as the planning criteria for determining the need for peak-hour capacity. The alternative scenarios are based on their respective peak-day average temperature probabilities to determine forecast outcomes.

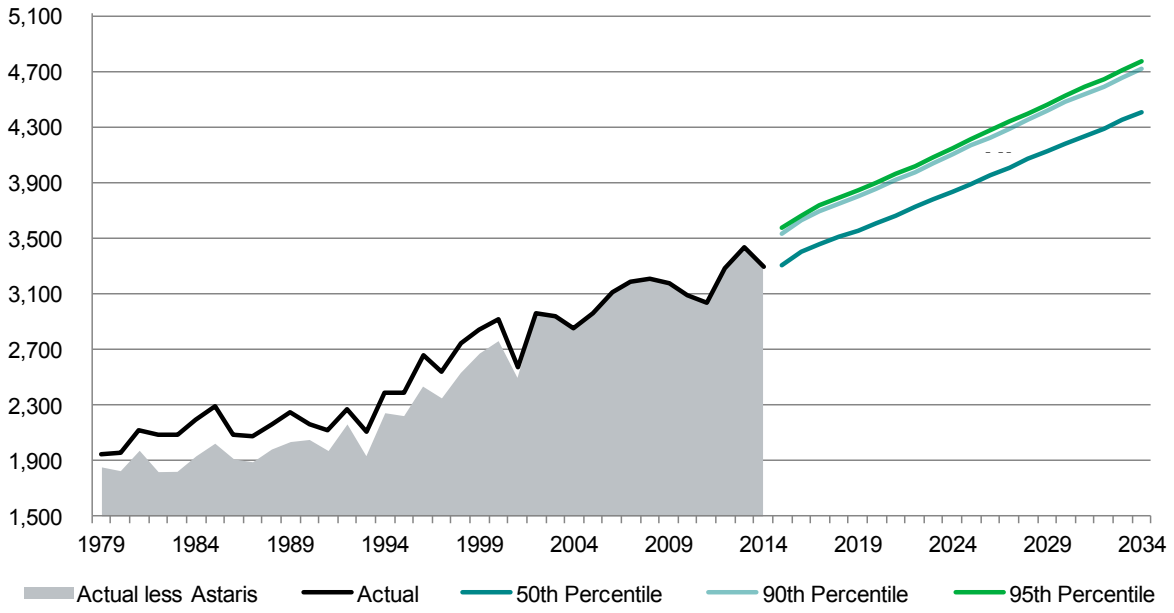


Figure 7.1 Peak-hour load-growth forecast (MW)

Table 7.1 Load forecast—peak hour (MW)

Year	Median	90th Percentile	95th Percentile
2014 (Actual)	3,184	3,184	3,184
2015	3,313	3,537	3,576
2016	3,401	3,630	3,669
2017	3,463	3,696	3,736
2018	3,514	3,752	3,793
2019	3,562	3,805	3,847
2020	3,615	3,862	3,905
2021	3,670	3,922	3,965
2022	3,725	3,981	4,026
2023	3,780	4,041	4,086
2024	3,839	4,105	4,151
2025	3,897	4,168	4,215
2026	3,956	4,231	4,278
2027	4,013	4,293	4,341
2028	4,071	4,355	4,404
2029	4,130	4,419	4,469
2030	4,187	4,481	4,531
2031	4,242	4,540	4,592
2032	4,296	4,599	4,651
2033	4,352	4,659	4,713
2034	4,407	4,719	4,773
Growth rate (2015–2034)	**1.5%**	**1.5%**	**1.5%**

The median or expected case peak-hour load forecast predicts that peak-hour load will grow from 3,313 MW in 2015 to 4,407 MW in 2034—an average annual compound growth rate of 1.5 percent. The projected average annual compound growth rate of the 95th-percentile peak forecast is also 1.5 percent. In the 95th-percentile forecast, summer peak-hour load is expected to increase from 3,576 MW in 2015 to 4,773 MW in 2034. Historical peak-hour loads, as well as the three forecast scenarios, are shown in Figure 7.1.

Idaho Power's winter peak-hour load record is 2,528 MW, recorded on December 10, 2009, at 8:00 a.m. Historical winter peak-hour load is much more variable than summertime peak-hour load. The winter peak variability is due to peak-day temperature variability in winter months, which is far greater than the variability of peak-day temperatures in summer months.

Average-Energy Load Forecast

Potential monthly average-energy use by customers in Idaho Power's service area is defined by three load forecasts that reflect load uncertainty resulting from different weather-related assumptions. Figure 7.2 and Table 7.2 show the results of the three forecasts used in the 2015 IRP as annual system load growth over the planning period. There is an approximately 50-percent probability Idaho Power's load will exceed the expected-case forecast, a 30-percent probability of load exceeding the 70th-percentile forecast, and a 10-percent probability of exceeding the 90th-percentile forecast. The projected 20-year average compound annual growth rate in each of the forecasts is 1.2 percent.

Idaho Power uses the 70th-percentile forecast as the basis for monthly average-energy planning in the IRP. The 70th-percentile forecast is based on 70th-percentile weather to forecast average monthly load, 70th-percentile water to forecast hydroelectric generation, and 95th-percentile average peak-day temperature to forecast monthly peak-hour load.

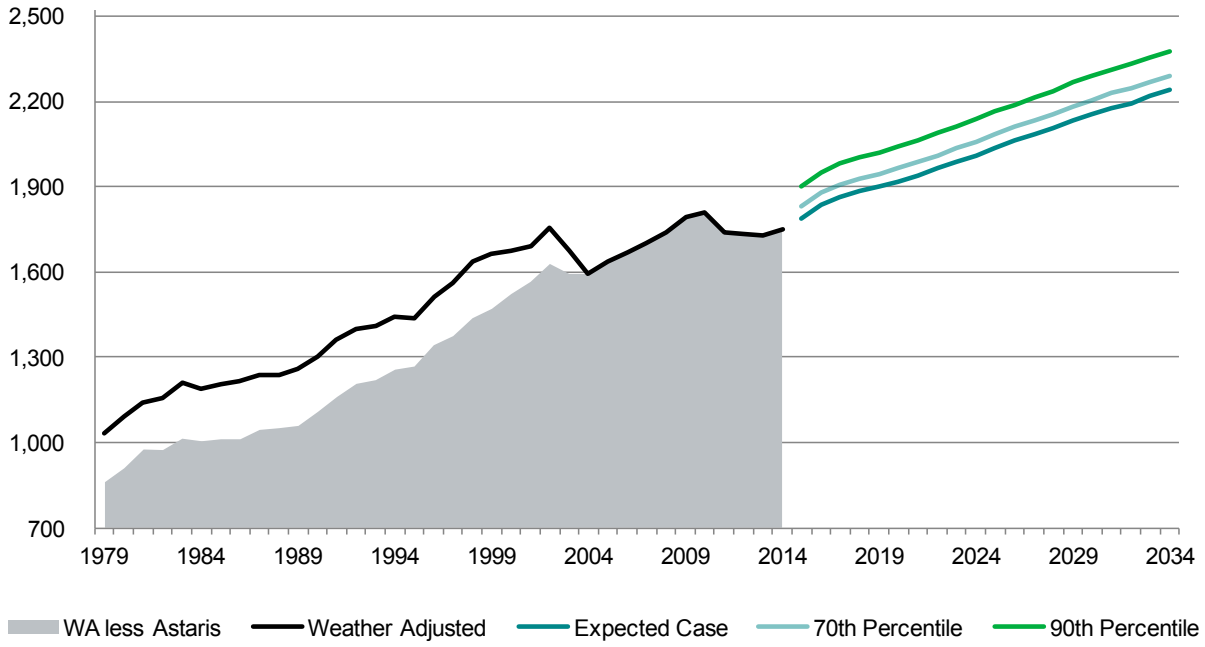


Figure 7.2 Average monthly load-growth forecast (aMW)

Table 7.2 Load forecast—average monthly energy (aMW)

Year	Median	70th Percentile	90th Percentile
2015	1,786	1,829	1,900
2016	1,835	1,878	1,950
2017	1,864	1,908	1,981
2018	1,883	1,928	2,002
2019	1,900	1,946	2,021
2020	1,918	1,964	2,040
2021	1,941	1,987	2,064
2022	1,964	2,011	2,088
2023	1,988	2,035	2,113
2024	2,012	2,059	2,139
2025	2,037	2,085	2,165
2026	2,061	2,110	2,190
2027	2,085	2,134	2,215
2028	2,107	2,156	2,238
2029	2,133	2,183	2,266
2030	2,156	2,206	2,290
2031	2,177	2,228	2,312
2032	2,195	2,246	2,331
2033	2,219	2,271	2,356
2034	2,240	2,292	2,378
Growth rate (2015–2034)	**1.2%**	**1.2%**	**1.2%**

Additional Firm Load

The additional firm-load category consists of Idaho Power's largest customers. Idaho Power's tariff requires the company to serve requests for electric service greater than 20 MW under a special-contract schedule negotiated between Idaho Power and each large-power customer. The contract and tariff schedule are approved by the appropriate commission. A special contract allows a customer-specific cost-of-service analysis and unique operating characteristics to be accounted for in the agreement. A special contract also allows Idaho Power to provide requested service consistent with system capability and reliability. Idaho Power currently has three special-contract customers recognized as firm-load customers: Micron Technology, Simplot Fertilizer, and the INL. The special-contract customers are described briefly as follows.

Micron Technology

Micron Technology represents Idaho Power's largest electric load for an individual customer and employs approximately 5,000 workers in the Boise MSA. The company operates its research and development fabrication facility in Boise and performs a variety of other activities, including product design and support; quality assurance (Q/A); systems integration; and related manufacturing, corporate, and general services. Micron Technology's electricity use is expected to increase based on the market demand for their products.

Simplot Fertilizer

The Simplot Fertilizer plant is the largest producer of phosphate fertilizer in the western US. The future electricity usage at the plant is expected to grow slowly through 2016, then stay flat throughout the remainder of the planning period.

Idaho National Laboratory

The DOE provided an energy-consumption and peak-demand forecast through 2034 for the INL. The forecast calls for loads to slowly rise through 2021, rise dramatically through 2024, and stay near that higher level throughout the remainder of the forecast period.

Generation Forecast for Existing Resources

To identify the need and timing of future resources, Idaho Power prepares a load and resource balance that accounts for forecast load growth and generation from all of the company's existing resources and planned purchases. Updated load and resource balance worksheets showing Idaho Power's existing and committed resources for average-energy and peak-hour load are shown in *Appendix C—Technical Appendix*. The following sections provide a description of Idaho Power's hydroelectric, thermal, and transmission resources and how they are accounted for in the load and resource balance.

Swan Falls Dam.

Hydroelectric Resources

For the 2015 IRP, Idaho Power continues using 70th-percentile forecast streamflow conditions for the Snake River Basin as the basis for the projections of monthly average hydroelectric generation. The 70th percentile means basin streamflows are expected to exceed the planning criteria 70 percent of the time and are expected to be worse than the planning criteria 30 percent of the time.

Likewise, for peak-hour resource adequacy, Idaho Power continues to assume 90th-percentile streamflow conditions to project peak-hour hydroelectric generation. The 90th percentile means streamflows are expected to exceed the planning criteria 90 percent of the time and to be worse than the planning criteria only 10 percent of the time.

The practice of basing hydroelectric generation forecasts on worse-than-median streamflow conditions was initially adopted in the 2002 IRP in response to suggestions that Idaho Power use more conservative water planning criteria as a method of encouraging the acquisition of sufficient firm resources to reduce reliance on market purchases. However, Idaho Power continues to prepare hydroelectric generation forecasts for 50th-percentile (median) streamflow conditions because the median streamflow condition is still used for rate-setting purposes and other analyses.

Idaho Power uses two primary models for forecasting future flows for the IRP. The Snake River Planning Model (SRPM) is used to determine surface-water flows, and the Enhanced Snake Plain Aquifer Model (ESPAM) is used to determine the effect of various aquifer management practices on Snake River reach gains. The two models are used in combination to produce a normalized hydrologic record for the Snake River Basin from 1928 through 2009. The record is normalized to account for specified conditions relating to Snake River reach gains, water-management facilities, irrigation facilities, and operations. The 50th-, 70th-, and 90th-percentile streamflow forecasts are derived from the normalized hydrologic record. Further discussion of flow modeling for the 2015 IRP is included in *Appendix C—Technical Appendix*.

A review of Snake River Basin streamflow trends suggests that persistent decline documented in the ESPA is mirrored by downward trends in total surface-water outflow from the river basin. The ESPA CAMP includes demand-reduction and weather-modification measures that will add new water to the basin water budget. Idaho Power believes the positive effect of the new water associated with the CAMP measures is likely to be temporary. The current water-use practices driving the steady decline over recent years are expected to continue, resulting in declining basin outflows assumed to persist well into the 2030s. The declining basin outflows for this IRP are assumed to continue through the planning period.

Oxbow Dam, part of the Hells Canyon Complex.

A water-management practice affecting Snake River streamflows involves the release of water to augment flows during salmon outmigration. Various federal agencies involved in salmon migration studies have, in recent years, supported efforts to shift the delivery of flow augmentation water from the Upper Snake River and Boise River basins from the traditional months of July and August to the spring months of April, May, and June. The objective of the streamflow augmentation is to more closely mimic the timing of naturally occurring flow conditions. Reported biological opinions indicate the shift in water delivery is most likely to occur during worse-than-median water years. During 2013—a year with markedly worse-than-median water conditions—flow augmentation water from the Upper Snake River and Boise River basins was delivered during May. Because worse-than-median water is assumed in the IRP, and because of the importance of July as a resource-constrained month, Idaho Power continues to incorporate the shifted delivery of flow augmentation water from the Upper Snake River and Boise River basins for the 2015 IRP. Augmentation water delivered from the Payette River Basin is assumed to remain in July and August.

The monthly average generation for Idaho Power's hydroelectric resources is calculated with a generation model developed internally by Idaho Power. The generation model treats the projects upstream of the HCC as ROR plants. The generation model mathematically manages reservoir storage in the HCC to meet the remaining system load while adhering to the operating

constraints on the level of Brownlee Reservoir and outflows from the Hells Canyon project. For peak-hour analysis, a review of historical operations was performed to yield relationships between monthly energy production and achieved one-hour peak generation. The projected peak-hour capabilities for the IRP were derived from historical operation data.

A representative measure of the streamflow condition for any given year is the volume of inflow to Brownlee Reservoir during the April-to-July runoff period. Figure 7.3 shows historical April-to-July Brownlee inflow as well as forecast Brownlee inflow for the 50th, 70th, and 90th percentiles. The historical record demonstrates the variability of inflows to Brownlee Reservoir. The forecast inflows do not reflect the historical variability but do include reductions related to declining base flows in the Snake River. As noted previously in this section, these declines are assumed to continue through the planning period.

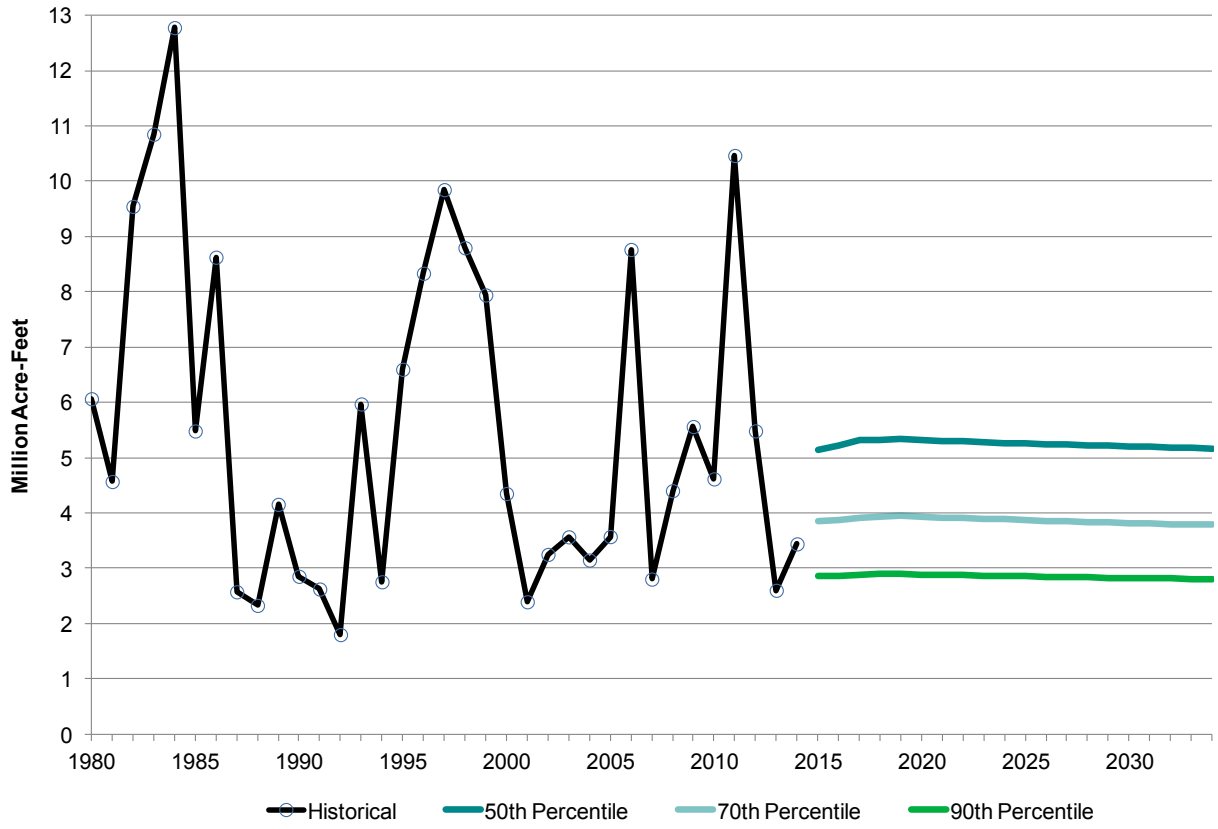


Figure 7.3 Brownlee historical and forecast inflows

Idaho Power recognizes the need to remain apprised of scientific advancements concerning climate change on a regional and global scale. Idaho Power believes there is too much uncertainty to predict the scale and timing of hydrologic effects due to climate change. Therefore, no adjustments related to climate change have been made in the 2015 IRP. A more complete discussion of climate change and expectations of possible effects on Snake River water supply is available starting on page 64 of the IDACORP, Inc., 2014 Form 10-K.

Coal Resources

Idaho Power's coal-fired generating facilities have typically operated as baseload resources. Monthly average-energy forecasts in the load and resource balance for the coal-fired projects are based on typical baseload output levels. Idaho Power schedules periodic maintenance to coincide with periods of high hydroelectric generation, seasonally low market prices, and moderate customer load. With respect to peak-hour output, the coal-fired projects are forecast to generate at the full-rated, maximum dependable capacity, minus 6 percent to account for forced outages. A summary of the expected coal price forecast is included in *Appendix C—Technical Appendix*.

Major plant modifications or changes in plant operations required to maintain compliance with air-quality standards are projected for the Jim Bridger units in 2015, 2016, 2021, and 2022 due to the Regional Haze final rulemaking.

The 2015 IRP assumes Idaho Power's share of the Boardman plant will not be available for coal-fired operations after December 31, 2020. This date is the result of an agreement reached between the ODEQ and PGE related to compliance with Regional Haze rules on particulate matter, SO_2, and NO_x emissions.

Coal Analysis

Idaho Power prepared an initial coal study as part of the *2011 IRP Update*, and the report was filed with the IPUC and OPUC in February 2013. The 2011 study evaluated several investment alternatives, including converting coal units to burn natural gas, installing SCR or selective non-catalytic reduction (SNCR), and scrubber additions. The study recommended installing SCR on Jim Bridger units 3 and 4 in 2015 and 2016, respectively. Since the completion of that initial coal study, the company has continued to monitor the costs and benefits associated with the SCR investments for Jim Bridger units 3 and 4 to ensure those investments remain cost-effective. An update to the economic analysis of the Bridger 3 and 4 SCR investments that supports the continued installation of the SCRs for those units is presented in *Appendix C—Technical Appendix* of the 2015 IRP.

There are no further environmental investment action items required by state or federal regulators prior to preparing and filing the 2017 IRP. In addition, there have been no material changes in the underlying forecast assumptions from the 2011 study. The company will evaluate investment alternatives for SCRs at Jim Bridger units 1 and 2 no later than the 2017 IRP.

Idaho Power seeks to balance the impacts of carbon regulation with the economic impact to customers, as well as customer needs for reliable service. For the 2015 IRP, the company applied a more dynamic economic analysis of the existing coal units compared to prior IRPs. The 2015 IRP evaluated numerous portfolios that included coal unit shutdowns on various dates. The company believes the termination of operations at its coal-fired plants in the very near future would lead to an increased risk of higher costs for customers in the near-term without a commensurate long-term economic benefit. The company is mindful that an early retirement of an asset requires accelerating the recovery of the remaining investment in that asset. This increases the cost in the early years to achieve longer-term savings.

Idaho Power has been in discussions with the joint owner of the North Valmy plant regarding the future of that plant. State public utility commissions and Idaho Power's customers expect future costs to be mitigated and balanced with future risks. Cost and risk will continue to be important factors in the utilities' discussions and decision processes.

Idaho Power currently benefits from the diversity of its generation resources, and that diversity helps mitigate the power supply cost risk borne by customers as the company transitions to the new energy landscape.

Natural Gas Resources

Idaho Power owns and operates four natural gas-fired SCCTs and one natural gas-fired CCCT. The SCCT units are typically operated during peak load events in summer and winter months. The monthly average-energy forecast for the SCCTs is based on the assumption that the generators are operated at full capacity for heavy-load hours during January, June, July, August, and December and produce approximately 230 aMW of gas-fired generation for the five months. With respect to peak-hour output, the SCCTs are assumed capable of producing an on-demand peak capacity of 416 MW. While the peak dispatchable capacity is assumed achievable for all months, it is most critical to system reliability during summer and winter peak-load months.

Idaho Power's CCCT, Langley Gulch, became commercially available in June 2012. Because of its higher efficiency rating, Langley Gulch is expected to be dispatched more frequently and for longer runtimes than the existing SCCTs. Langley Gulch is forecast to contribute approximately 165 aMW, with an on-demand peaking capacity of 318 MW.

Natural Gas Price Forecast

Future natural gas price assumptions significantly influence the financial results of the operational modeling used to evaluate and rank resource portfolios. For the 2015 IRP, Idaho Power is using the US Energy Information Administration (EIA) natural gas price forecast. Idaho Power also used the EIA as the source for the natural gas price forecast for the 2013 IRP and continues to use the EIA forecast for Idaho-jurisdiction avoided cost-calculation purposes. The natural gas price forecast was discussed during the first three monthly IRPAC meetings held in August through October 2014. During these discussions, Idaho Power provided comparisons of the EIA natural gas price forecast to an alternative forecast, as well as comparisons to observed settlement prices for futures trading in the natural gas market.

The *Annual Energy Outlook 2014*, published by the EIA in April 2014, is the source for the natural gas price forecast for the 2015 IRP. For the 2015 IRP, Idaho Power uses nominal prices, as published by the EIA, as inputs to the analysis performed. Figure 7.4 shows forecast Henry Hub natural gas prices. The low- and high-case natural gas price forecasts used for the 2015 IRP and shown on the chart correspond respectively to the high resource (high availability) and low resource (low availability) cases reported by the EIA in the *Annual Energy Outlook 2014*. Idaho Power applies a Sumas basis and transportation cost to the Henry Hub price to derive an Idaho Citygate price. The Idaho Citygate price is representative of the gas price delivered to Idaho Power's natural gas plants. The Idaho Citygate price forecast is provided in *Appendix C—Technical Appendix*.

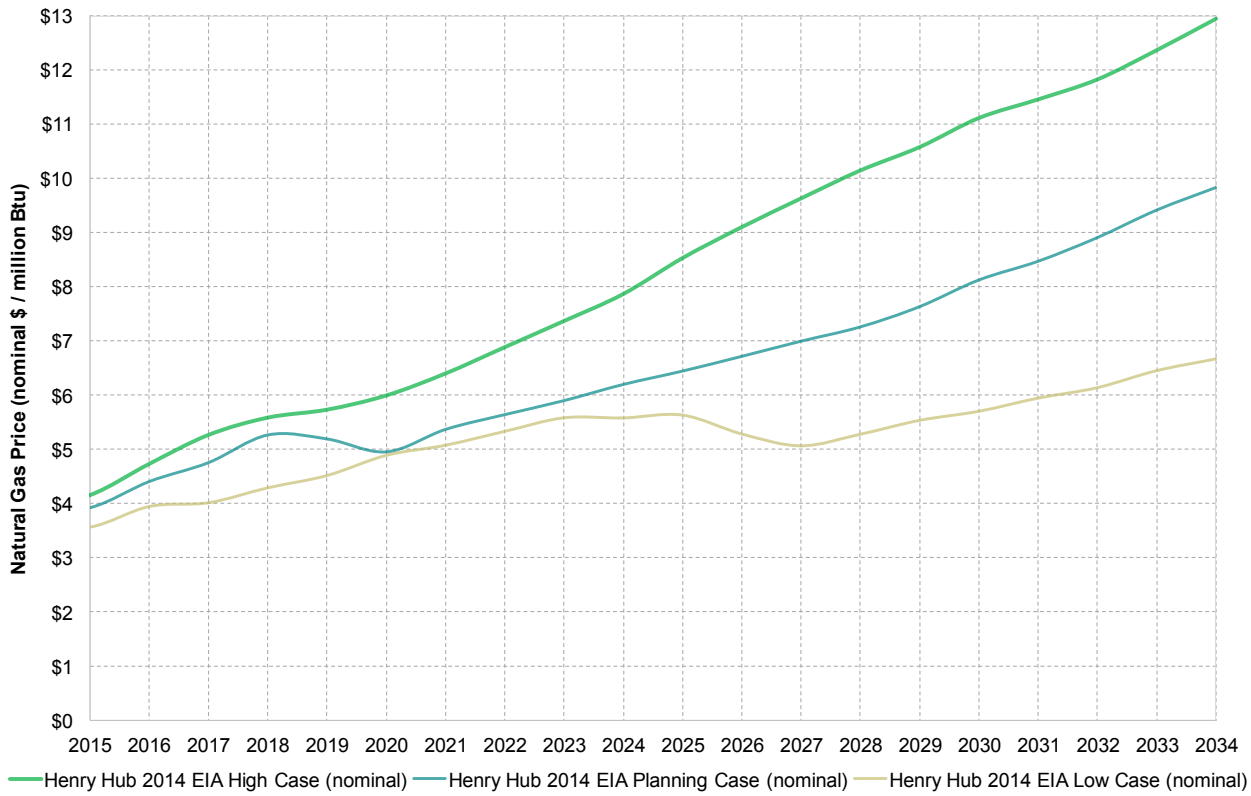


Figure 7.4 Henry Hub price forecast—EIA *Annual Energy Outlook 2014* (nominal dollars)

Resource Cost Analysis

A comparative cost analysis of a variety of supply-side and demand-side resources was conducted as part of resource screening for the 2015 IRP. As described previously, cost inputs and operating data used to develop the resource cost analysis were derived from the September 2014 Lazard report, Idaho Power engineering studies and operating experience, and consultation with specific resource developers. Resource costs are presented as follows:

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

The capital cost of solar PV resources has been the subject of considerable IRPAC discussions over recent IRPs. As widely reported, solar PV costs have declined markedly over recent years, presenting unique challenges in determining appropriate costs for solar resources. For the 2015 IRP, Idaho Power used the Lazard report's projected 2017 capital cost of $1,250 per kW for utility-scale, single-axis tracking solar PV resources. To further capture reported trends in solar PV capital costs, the 2015 IRP capital cost of $1,250 per kW was not escalated according to the IRP's assumed level of inflation, as the capital costs for other considered resources were.

For the 2015 IRP, Idaho Power is including in resource cost calculations the assumption that potential IRP resources have varying economic life. Financial analyses for the IRP assume the annual depreciation expense of capital costs is based on an apportioning of the capital costs over the entire economic life of a given resource.

The levelized costs for the various supply-side alternatives include capital costs, O&M costs, fuel costs, and other applicable adders and credits. The initial capital investment and associated capital costs of supply-side resources include engineering development costs, generating and ancillary equipment purchase costs, installation costs, applicable balance of plant construction costs, and the costs for a transmission interconnection to Idaho Power's network system. The capital costs also include an 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. The value of RECs is not included in the levelized cost estimates but is accounted for when analyzing the total cost of each resource portfolio.

The levelized costs for each of the demand-side resource options include annual administrative and marketing costs of the program, an annual incentive, and annual participant costs. The demand-side resource costs do not reflect the financial effects resulting from the load-reduction programs.

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

Resource Cost Analysis II—Resource Stack

Levelized Capacity (Fixed) Cost

The annual fixed-revenue requirements in nominal dollars for each resource were summed and levelized over the assumed economic life and are presented in terms of dollars per kW of plant nameplate capacity per month. Included in these levelized fixed costs are the initial resource investment and associated capital cost and fixed O&M estimates. As noted earlier, resources are considered to have varying economic life, and the financial analysis to determine the annual depreciation of capital costs is based on an apportioning of the capital costs over the entire economic life. Figure 7.5 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 that natural gas peaking resources and demand response are the lowest capacity-cost alternatives. The natural gas peaking resources have high operating costs, but operating costs are less important for resources intended for use only during a limited number of hours per year to meet peak-hour demand.

Levelized Cost of Production

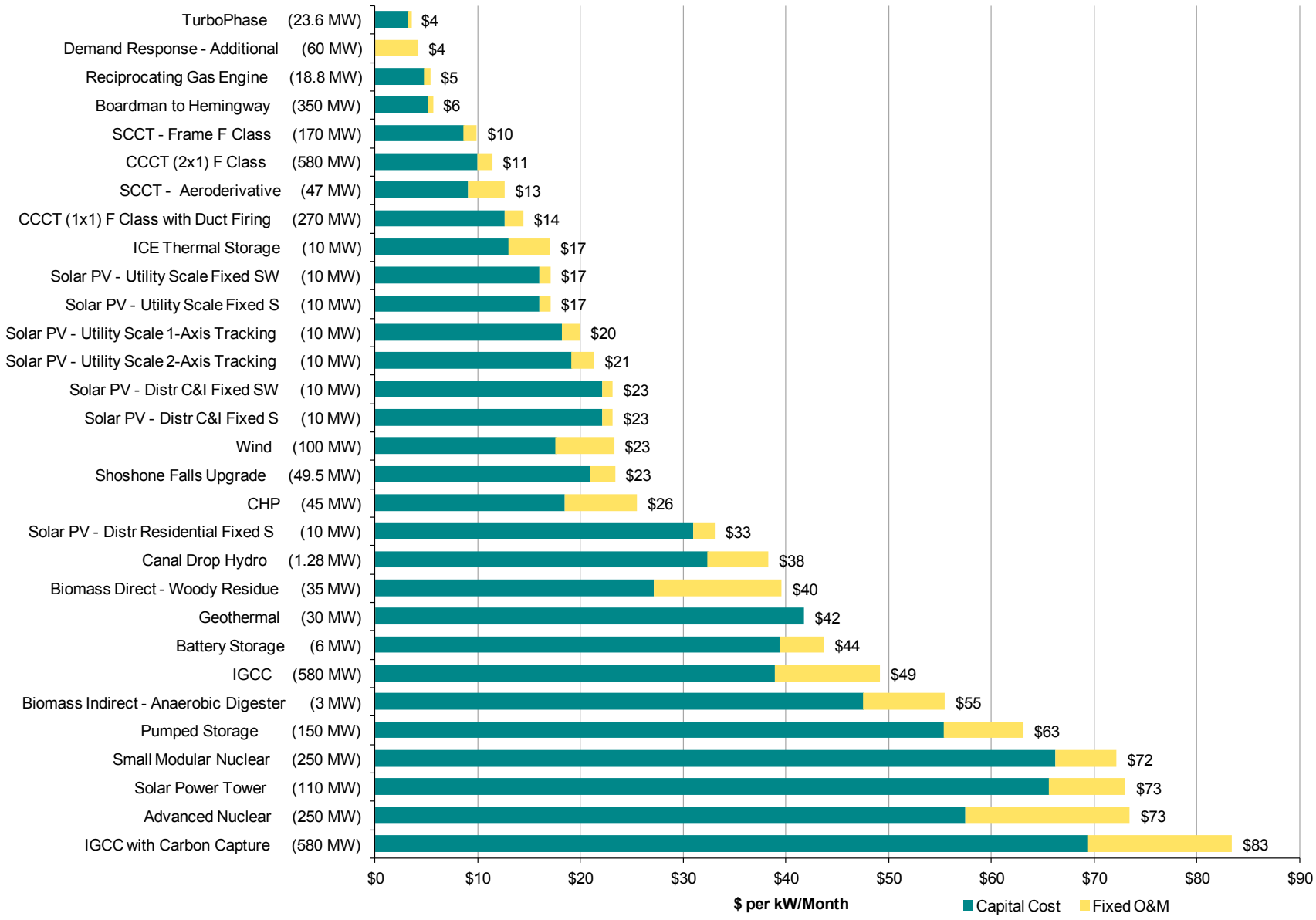
Certain resource alternatives carry low fixed costs and high variable operating costs, while other alternatives require significantly higher capital investment and fixed operating costs but have low variable operating costs. The levelized cost-of-production measurement represents the estimated annual cost (revenue requirements) per MWh in nominal dollars for a resource based on an expected level of energy output (capacity factor) over the economic life of the resource.

The nominal, levelized cost of production assuming the expected capacity factors for each resource type is shown in Figure 7.6. Included in these costs are the capital cost, non-fuel O&M, fuel, and emissions adders; however, no value for RECs was assumed in this analysis. The B2H transmission line is among the lowest-cost resources for meeting baseload requirements.

When evaluating a levelized cost for a project and comparing it to the levelized cost of another project, it is important to use consistent assumptions for the computation of each number. The levelized cost-of-production metric represents the annual cost of production over the life of a resource converted into an equivalent annual annuity. This is similar to the calculation used to determine a car payment; only, in this case, the car payment would also include the cost of gasoline to operate the car and the cost of maintaining the car over its useful life.

An important input into the levelized cost-of-production calculation for a generation resource is the assumed level of annual capacity use over the life of the resource, referred to as the capacity factor. A capacity factor of 50 percent would suggest a resource would be expected to produce output at full capacity 50 percent of the hours during the year. Therefore, at a higher capacity factor, the levelized cost would be less because the plant would generate more MWh over which to spread the fixed costs. Conversely, lower capacity-factor assumptions reduce the MWh, and the levelized cost would be higher.

For the portfolio cost analysis, fixed resource costs are annualized over the assumed economic life for each resource and are applied only to the years of production within the IRP planning period, thereby accounting for end effects.


TurboPhase (23.6 MW) $4
Demand Response - Additional (60 MW) $4
Reciprocating Gas Engine (18.8 MW) $5
Boardman to Hemingway (350 MW) $6
SCCT - Frame F Class (170 MW) $10
CCCT (2x1) F Class (580 MW) $11
SCCT - Aeroderivative (47 MW) $13
CCCT (1x1) F Class with Duct Firing (270 MW) $14
ICE Thermal Storage (10 MW) $17
Solar PV - Utility Scale Fixed SW (10 MW) $17
Solar PV - Utility Scale Fixed S (10 MW) $17
Solar PV - Utility Scale 1-Axis Tracking (10 MW) $20
Solar PV - Utility Scale 2-Axis Tracking (10 MW) $21
Solar PV - Distr C&I Fixed SW (10 MW) $23
Solar PV - Distr C&I Fixed S (10 MW) $23
Wind (100 MW) $23
Shoshone Falls Upgrade (49.5 MW) $23
CHP (45 MW) $26
Solar PV - Distr Residential Fixed S (10 MW) $33
Canal Drop Hydro (1.28 MW) $38
Biomass Direct - Woody Residue (35 MW) $40
Geothermal (30 MW) $42
Battery Storage (6 MW) $44
IGCC (580 MW) $49
Biomass Indirect - Anaerobic Digester (3 MW) $55
Pumped Storage (150 MW) $63
Small Modular Nuclear (250 MW) $72
Solar Power Tower (110 MW) $73
Advanced Nuclear (250 MW) $73
IGCC with Carbon Capture (580 MW) $83
$0 $10 $20 $30 $40 $50 $60 $70 $80 $90
$ per kW/Month
Capital Cost
Fixed O&M

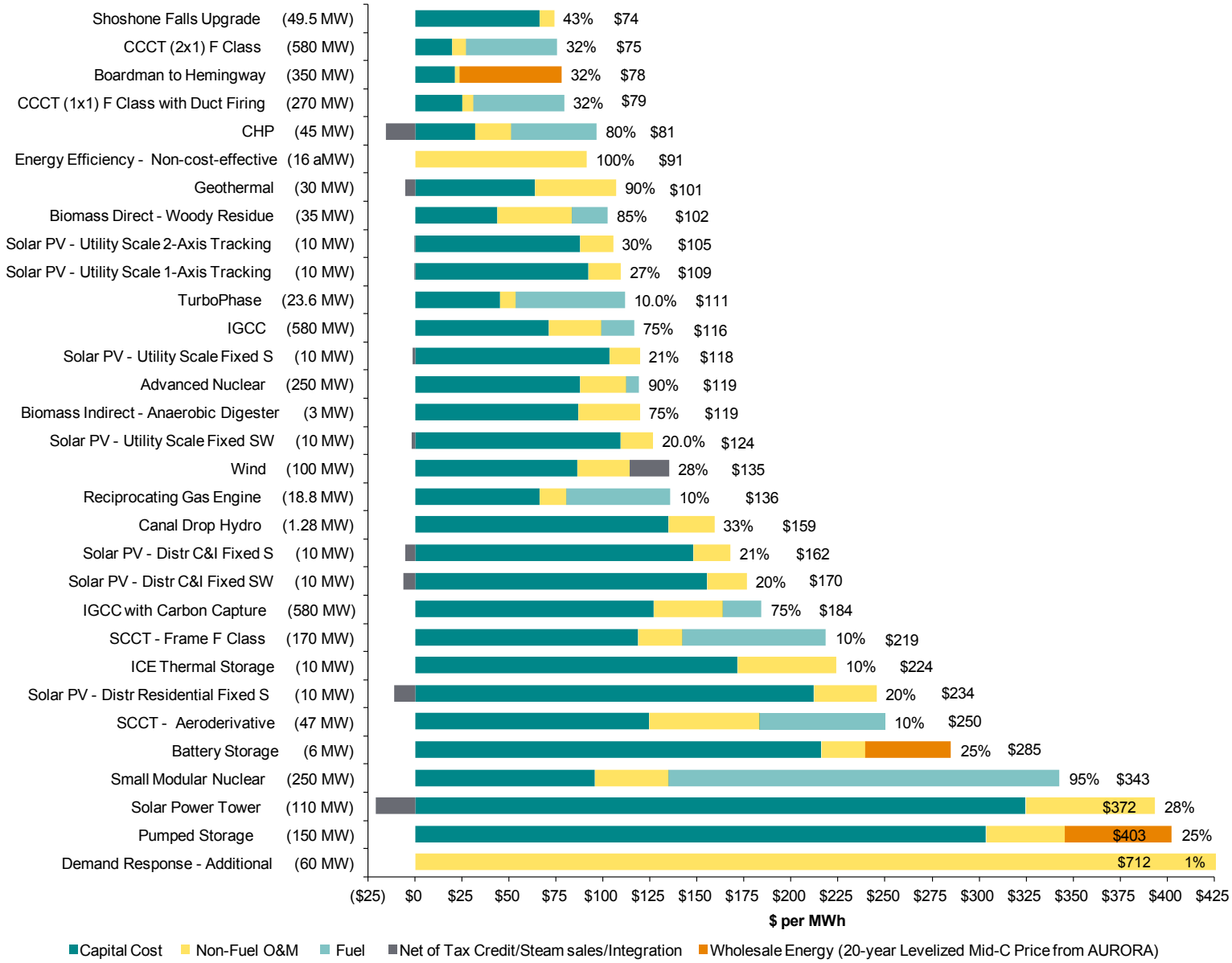


Figure 7.6 30-year levelized cost of production (at stated capacity factors)

Supply-Side Resource Costs

Idaho Power prefers to use independent estimates of the supply-side resource costs when the estimates are available. For the 2015 IRP, Idaho Power used the 2014 Lazard report as the primary source for supply-side resource costs. Idaho Power engineering studies and plant operating experience were also used. Costs for select resources not provided by the Lazard report and for which Idaho Power has limited engineering and operating experience were determined through consultation with specific resource developers.

The 2015 IRP forecasts load growth in Idaho Power's service area and identifies supply-side resources and demand-side measures necessary to meet the future energy needs of customers. The 2015 IRP has identified periods of future system deficiencies. New resource costs are levelized estimates (based on expected annual generation) that include capital, fuel, and non-fuel O&M. Figure 7.7 shows the capital costs in nominal dollars per kW for a new resource with a 2020 online date plotted against peak-hour capacity for various supply-side resources considered in the 2015 IRP. The on-line date of 2020 is used because, depending on the coal-retirement scenario, the earliest date for new resources in the 2015 IRP is 2020. The use of the 2020 on-line date also allows projected 2015 to 2016 capital-cost declines in utility-scale PV solar to be captured in the plotted data.

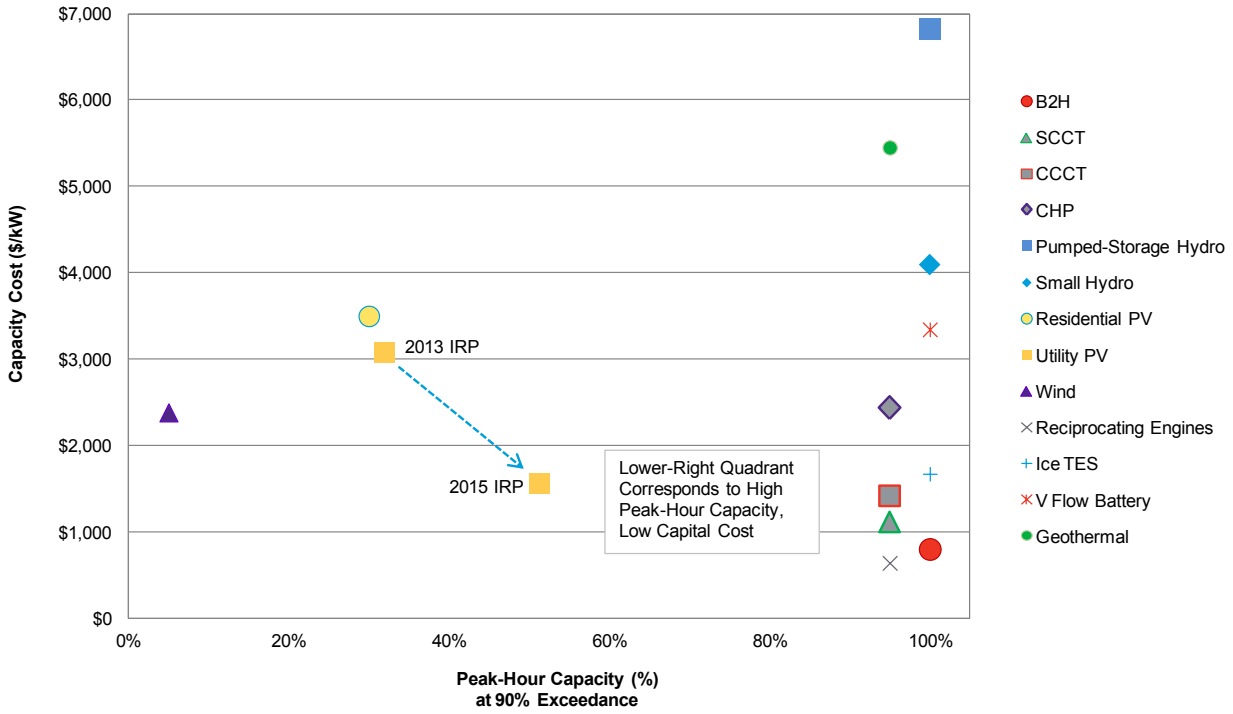


Figure 7.7 Capacity cost of new supply-side resources, online 2020

Resources in the lower-right portion of Figure 7.7 are considered to provide peak-hour capacity at a relatively low capital cost. Among the resources in the lower-right portion, the B2H transmission line and various natural-gas fired generating resources provide the highest peak-hour capacity at the lowest cost. Ice-based TES also appears in the lower-right portion as a relatively low-cost capacity resource. The dashed arrow on the figure represents the notable shift in assumptions since the 2013 IRP for utility-scale PV solar. The marked decline in PV solar

capital costs has been extensively reported over recent years. The shift in peak-hour capacity is based on an analysis performed for the 2015 IRP indicating peak-hour capacity slightly in excess of 50 percent of nameplate capacity for single-axis PV solar power plants. This analysis is described in Chapter 5.

While it is important to evaluate the costs presented in Figure 7.7, these costs represent only part of the TRC. In preparing the IRP, Idaho Power also considers the value each resource provides in conjunction with the existing resources in the company's generation portfolio; supply-side resources have different operating characteristics, making some better suited for meeting capacity needs, while others are better for providing energy.

Figure 7.8 shows the levelized cost of energy in dollars per MWh for various new supply-side resources considered in the 2015 IRP, where costs considered include those related to building and operating the resource for a 20-year period. The data used to create Figure 7.8 allows for resource alternatives to be compared based on the capacity cost and the total levelized cost of production.

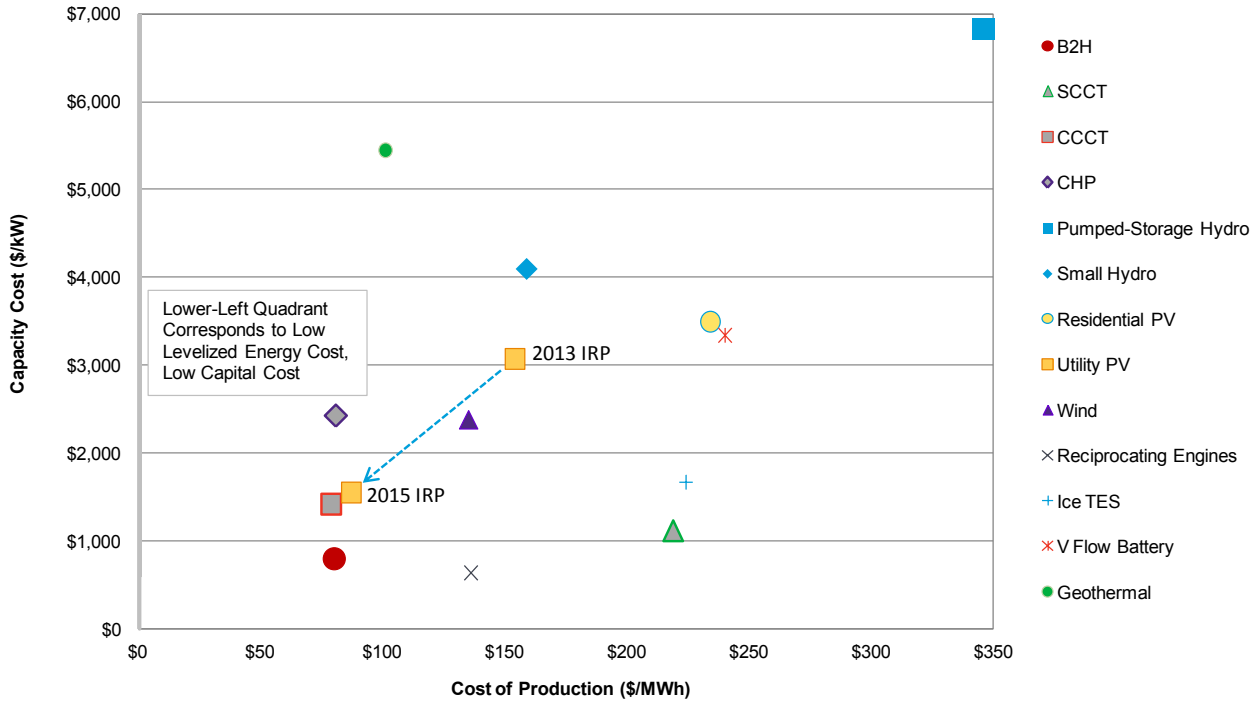


Figure 7.8 Energy cost of new supply-side resources

Resources in the lower-left portion of Figure 7.8 produce (or deliver) energy at a low levelized cost and have a relatively low capital cost. The B2H transmission line is among those resources having low levelized costs and low capital costs. Figures 7.7 and 7.8 respectively demonstrate that the B2H transmission line is attractive as a capacity resource (i.e., one needed relatively infrequently) and energy resource (i.e., one needed for frequent energy delivery). In contrast, a SCCT has competitive costs with respect to the relatively infrequent delivery of capacity (Figure 7.7) but is much less competitive when required to deliver energy (Figure 7.8). The dashed line represents the capital-cost decrease observed in utility-scale PV solar since the 2013 IRP.

Load and Resource Balance

Idaho Power has adopted the practice of assuming drier-than-median water conditions and higher-than-median load conditions in its resource planning process. Targeting a balanced position between load and resources while using the conservative water and load conditions is considered comparable to requiring a capacity margin in excess of load while using median load and water conditions. Both approaches are designed to result in a system having a sufficient generating reserve capacity to meet daily operating reserve requirements.

To identify the need and timing of future resources, Idaho Power prepares the load and resource balance, which accounts for generation from all the company's existing resources and planned purchases. Due to the uncertainty of the CAA Section 111(d) regulation, many different assumptions can be made for the future of Idaho Power's coal resources. To address these different coal futures, Idaho Power analyzed nine load and resource balance scenarios:

- **Status Quo:** The first scenario assumes Idaho Power makes no changes in the operations of its coal fleet. This scenario is very similar to the load and resource balance provided in the 2013 IRP and is designed to provide a basis for comparison.

- **Maintain Coal Capacity**: The second scenario assumes Idaho Power will maintain its coal fleet but reduce emissions output in compliance with the proposed CAA Section 111(d) regulation by limiting or capping the amount generators can run.

- **Retire North Valmy Coal Plant:** A third set of scenarios assumes varying timing dates for the retirement of units 1 and 2 of the North Valmy coal plant. There are four scenarios that reflect possible retirement dates for units 1 and 2 of North Valmy:

    - Retire units 1 and 2 by the end of 2019

    - Retire units 1 and 2 by the end of 2025

    - Retire Unit 1 by the end of 2019 and Unit 2 by the end of 2025

    - Retire Unit 1 by the end of 2021 and Unit 2 by the end of 2025

- **Retire units 1 and 2 of Jim Bridger Coal Plant:** Two sets of scenarios assume different retirement dates for units 1 and 2 of the Jim Bridger coal plant. There are a total of four units at Jim Bridger, and units 3 and 4 are not being considered for retirement.

    - Retire Unit 1 by the end of 2023 and Unit 2 by the end of 2028

    - Retire Unit 1 by the end of 2023 and Unit 2 by the end of 2032

- **Retire North Valmy Coal Plant and units 1 and 2 of Jim Bridger Coal Plant:** A final scenario assumes the retirement of units 1 and 2 of North Valmy coal plant by the end of 2025, retirement of Unit 1 of Jim Bridger coal plant by the end of 2023, and retirement of Unit 2 of Jim Bridger by the end of 2032.

Each scenario will include a load and resource balance using average monthly energy planning assumptions and peak-hour planning assumptions.

Average-energy surpluses and deficits are determined using 70th-percentile water and 70th-percentile average load conditions, coupled with Idaho Power's ability to import energy from firm market purchases using a reserved network capacity.

Peak-hour load deficits are determined using 90th-percentile water and 95th-percentile peak-hour load conditions. The hydrologic and peak-hour load criteria are the major factors in determining peak-hour load deficits. Peak-hour load planning criteria are more stringent than average-energy criteria because Idaho Power's ability to import additional energy is typically limited during peak-hour load periods.

All load and resource balances, irrespective of the coal future under consideration, include the following:

- Existing demand reduction due to the demand response programs and the forecast effect of existing energy efficiency programs.

- Existing PPAs with Elkhorn Valley Wind, Raft River Geothermal, and Neal Hot Springs. Idaho Power's agreement with Elkhorn Valley Wind expires at the end of 2027. The other agreements do not expire within the planning period.

- Firm Pacific Northwest import capability. This does not include the import capacity from the B2H transmission line or the Gateway West transmission line.

- Expected generation from all Idaho Power-owned resources. The Boardman coal plant has a planned retirement date of 2020.

- Existing PURPA projects and contracts completed by October 31, 2014, including 461 MW of solar projects under contract but not yet operational. (Contracts for four solar projects totaling 141 MW of installed capacity were terminated on April 6, 2015. The relatively late termination date precludes the removal of these projects from the load and resource balance analysis for the 2015 IRP.) Idaho Power assumes all PURPA contracts, with the exception of wind projects, will continue to deliver energy throughout the planning period, and the renewal of contracts will be consistent with PURPA rules and regulations existing at the time the new contracts are negotiated. Wind projects are not expected to be renewed. There is a total of 627 MW of wind under contract. Wind contracts begin to expire in October 2025, and the total wind under contract drops to 130 MW at the end of the planning period.

At times of peak summer load, Idaho Power is using all ATC from the Pacific Northwest. If Idaho Power encountered a significant outage at one of its main generation facilities or a transmission interruption on one of the main import paths, the company would fail to meet reserve requirement standards. If Idaho Power was unable to meet reserve requirements, the company would be required to shed load by initiating rolling blackouts. Although infrequent, Idaho Power has initiated rolling blackouts in the past during emergencies. Idaho Power has

committed to a build program, including demand-side programs, generation, and transmission resources, to reliably meet customer demand and minimize the likelihood of events that would require the implementation of rolling blackouts.

Idaho Power's customers reach a maximum energy demand in the summer. From a resource adequacy perspective, July has historically been the month during which Idaho Power's system is most constrained. Based on projections for the 2015 IRP, July is likely to remain the most resource-constrained month. A secondary maximum energy demand occurs during the winter in the month of December. Tables 7.3 and 7.4 provide for July and December the monthly average-energy deficits for each of the coal futures considered in the 2015 IRP. Darker shading in the tables corresponds with larger deficits. Surplus positions are not specified in the tables. Because no deficits exist prior to 2020, the tables include data for only the period 2020 to 2034.

Table 7.3 July monthly average energy deficits (average MW) by coal future with existing and committed supply- and demand-side resources (70th-percentile water and 70th-percentile load)

Energy Deficits (aMW)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Status Quo	–	–	–	–	–	–	–	–	–	–	–	(1)	(52)	(121)	(145)
Maintain Coal Capacity	–	–	–	–	–	–	–	–	–	(3)	(69)	(135)	(186)	(255)	(279)
Valmy Retire Units 1 and 2 Year–End 2019	–	–	–	–	–	–	(34)	(59)	(112)	(149)	(186)	(251)	(303)	(371)	(396)
Valmy Retire Units 1 and 2 Year–End 2025	–	–	–	–	–	–	(34)	(59)	(112)	(149)	(186)	(251)	(303)	(371)	(396)
Valmy Retire Unit 1 Year–End 2019 and Unit 2 Year–End 2025	–	–	–	–	–	–	(34)	(59)	(112)	(149)	(186)	(251)	(303)	(371)	(396)
Valmy Retire Unit 1 Year–End 2021 and Unit 2 Year–End 2025	–	–	–	–	–	–	(34)	(59)	(112)	(149)	(186)	(251)	(303)	(371)	(396)
Bridger Retire Unit 1 Year–End 2023 and Unit 2 Year–End 2028	–	–	–	–	–	(3)	(51)	(76)	(129)	(329)	(395)	(460)	(511)	(580)	(605)
Bridger Retire Unit 1 Year–End 2023 and Unit 2 Year–End 2032	–	–	–	–	–	(3)	(51)	(76)	(129)	(166)	(232)	(298)	(349)	(580)	(605)
Bridger Retire Unit 1 Year–End 2023 and Unit 2 Year–End 2032, Valmy Retire Units 1 and 2 Year–End 2025	–	–	–	–	–	(3)	(197)	(222)	(275)	(312)	(349)	(414)	(465)	(697)	(721)

Table 7.4 December monthly average energy deficits (average MW) by coal future with existing and committed supply- and demand-side resources (70th-percentile water and 70th-percentile load)

Energy Deficits (aMW)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Status Quo	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Maintain Coal Capacity	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Valmy Retire Units 1 and 2 Year-End 2019	–	–	–	–	–	–	–	–	–	–	–	–	–	(16)	(35)
Valmy Retire Units 1 and 2 Year-End 2025	–	–	–	–	–	–	–	–	–	–	–	–	–	(16)	(35)
Valmy Retire Unit 1 Year-End 2019 and Unit 2 Year-End 2025	–	–	–	–	–	–	–	–	–	–	–	–	–	(16)	(35)
Valmy Retire Unit 1 Year-End 2021 and Unit 2 Year-End 2025	–	–	–	–	–	–	–	–	–	–	–	–	–	(16)	(35)
Bridger Retire Unit 1 Year-End 2023 and Unit 2 Year-End 2028	–	–	–	–	–	–	–	–	–	(32)	(64)	(149)	(180)	(239)	(259)
Bridger Retire Unit 1 Year-End 2023 and Unit 2 Year-End 2032	–	–	–	–	–	–	–	–	–	–	–	–	(17)	(239)	(259)
Bridger Retire Unit 1 Year-End 2023 and Unit 2 Year-End 2032, Valmy Retire Units 1 and 2 Year-End 2025	–	–	–	–	–	–	–	–	–	–	(3)	(88)	(119)	(341)	(361)

Tables 7.5 and 7.6 provide the peak-hour capacity deficits for July and December for the coal futures considered. Darker shading in the tables corresponds to larger deficits. Surplus positions are not specified in the tables. Because no deficits exist prior to 2020, the tables include data only for 2020 to 2034.

Table 7.5 July monthly peak-hour capacity deficits (MW) by coal future with existing and committed supply- and demand-side resources (90th-percentile water and 95th-percentile load)

Energy Deficits (aMW)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Status Quo	–	–	–	–	–	(14)	(61)	(136)	(175)	(224)	(316)	(352)	(426)	(491)	(523)
Maintain Coal Capacity	–	–	–	–	–	(14)	(61)	(136)	(175)	(224)	(316)	(352)	(426)	(491)	(523)
Valmy Retire Units 1 and 2 Year-End 2019	(24)	(141)	(143)	(176)	(236)	(277)	(324)	(399)	(438)	(487)	(579)	(615)	(689)	(754)	(786)
Valmy Retire Units 1 and 2 Year-End 2025	–	–	–	–	–	(14)	(324)	(399)	(438)	(487)	(579)	(615)	(689)	(754)	(786)
Valmy Retire Unit 1 Year-End 2019 and Unit 2 Year-End 2025	–	(9)	(11)	(44)	(105)	(145)	(324)	(399)	(438)	(487)	(579)	(615)	(689)	(754)	(786)
Valmy Retire Unit 1 Year-End 2021 and Unit 2 Year-End 2025	–	–	(11)	(44)	(105)	(145)	(324)	(399)	(438)	(487)	(579)	(615)	(689)	(754)	(786)
Bridger Retire Unit 1 Year-End 2023 and Unit 2 Year-End 2028	–	–	–	–	(149)	(190)	(236)	(312)	(350)	(576)	(667)	(703)	(777)	(842)	(874)
Bridger Retire Unit 1 Year-End 2023 and Unit 2 Year-End 2032	–	–	–	–	(149)	(190)	(236)	(312)	(350)	(400)	(491)	(527)	(601)	(842)	(874)
Bridger Retire Unit 1 Year-End 2023 and Unit 2 Year-End 2032, Valmy Retire Units 1 and 2 Year-End 2025	–	–	–	–	(149)	(190)	(499)	(575)	(613)	(663)	(754)	(790)	(864)	(1,105)	(1,137)

Table 7.6 December monthly peak-hour capacity deficits (MW) by coal future with existing and committed supply- and demand-side resources (90th-percentile water and 95th-percentile load)

Energy Deficits (aMW)	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Status Quo	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Maintain Coal Capacity	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Valmy Retire Units 1 and 2 Year-End 2019	–	–	–	–	–	–	(12)	(32)	(59)	(58)	(99)	(129)	(158)	(187)	(165)
Valmy Retire Units 1 and 2 Year-End 2025	–	–	–	–	–	–	(12)	(32)	(59)	(58)	(99)	(129)	(158)	(187)	(165)
Valmy Retire Unit 1 Year-End 2019 and Unit 2 Year-End 2025	–	–	–	–	–	–	(12)	(32)	(59)	(58)	(99)	(129)	(158)	(187)	(165)
Valmy Retire Unit 1 Year-End 2021 and Unit 2 Year-End 2025	–	–	–	–	–	–	(12)	(32)	(59)	(58)	(99)	(129)	(158)	(187)	(165)
Bridger Retire Unit 1 Year-End 2023 and Unit 2 Year-End 2028	–	–	–	–	–	–	–	–	–	(147)	(188)	(218)	(247)	(276)	(254)
Bridger Retire Unit 1 Year-End 2023 and Unit 2 Year-End 2032	–	–	–	–	–	–	–	–	–	–	(12)	(42)	(71)	(276)	(254)
Bridger Retire Unit 1 Year-End 2023 and Unit 2 Year-End 2032, Valmy Retire Units 1 and 2 Year-End 2025	–	–	–	–	–	–	(187)	(207)	(235)	(234)	(275)	(305)	(334)	(539)	(517)

8. PORTFOLIO SELECTION

Portfolio Design

In the 2015 IRP, Idaho Power continued the 2013 IRP's practice of analyzing a range of coal-retirement portfolios. The consideration of additional early coal retirement, or early shutdown portfolios is consistent with expectations expressed by the IPUC in its Acceptance of Filing order for the 2013 IRP (Case No. IPC-E-13-15, Order No. 32980). The 23 portfolios analyzed for the 2015 IRP can be grouped into the following 10 categories. All portfolios are assumed to have SCR installation for Jim Bridger units 3 and 4 completed by 2016.

1. **Status quo portfolio**—A single resource portfolio with no additional retirement of coal-fired generating units other than Boardman in 2020 and without output constraints related to the proposed CAA Section 111(d) regulation. The status quo portfolio relies on the B2H transmission line and reciprocating gas engines to meet future resource needs.

   All other portfolios considered in the 2015 IRP assume compliance with CAA Section 111(d) based on various assumptions regarding what the final regulation will contain.

2. **Maintain coal capacity portfolios**—A set of three portfolios with no retirement of coal capacity during the IRP planning period with the exception of the planned 2020 year-end Boardman shutdown.

3. **North Valmy retirement year-end 2019 portfolios**—A set of five portfolios with the retirement of both North Valmy units at year-end 2019.

4. **North Valmy retirement year-end 2025 portfolios**—A set of three portfolios with the retirement of both North Valmy units at year-end 2025.

5. **North Valmy staggered retirement year-end 2019 (Unit 1) and year-end 2025 (Unit 2) portfolios**—A set of two portfolios with retirement of North Valmy Unit 1 at year-end 2019 and Unit 2 at year-end 2025.

6. **North Valmy staggered retirement year-end 2021 (Unit 1) and year-end 2025 (Unit 2) portfolio**—A single portfolio with the retirement of North Valmy Unit 1 at year-end 2021 and Unit 2 at year-end 2025.

7. **Jim Bridger staggered retirement year-end 2023 (Unit 1) and year-end 2032 (Unit 2) portfolios**—A set of two portfolios with the retirement of Jim Bridger Unit 1 at year-end 2023 and Unit 2 at year-end 2032. The early retirement of these portfolios is assumed to allow avoiding installation of SCRs for Unit 1 in 2022 and Unit 2 in 2021.

8. **Jim Bridger staggered retirement year-end 2023 (Unit 1) and year-end 2028 (Unit 2) portfolio**—A single portfolio with the retirement of Jim Bridger Unit 1 at year-end 2023 and Unit 2 at year-end 2028. The early retirement of this portfolio is assumed to allow avoiding installation of SCRs for Unit 1 in 2022 and Unit 2 in 2021.

9. **Jim Bridger staggered retirement year-end 2023 (Unit 1) and year-end 2032 (Unit 2), North Valmy retirement year-end 2025 portfolio**—A single portfolio with the retirement of Jim Bridger Unit 1 at year-end 2023 and Unit 2 at year-end 2028, and the retirement of both North Valmy units at year-end 2025. The early Jim Bridger retirement in this portfolio is assumed to allow avoiding installation of SCRs for Unit 1 in 2022 and Unit 2 in 2021.

10. **Alternative to B2H portfolios**—A set of four portfolios in which the B2H transmission line is replaced by alternative resources. Except for this set of portfolios, all other 2015 IRP portfolios have the B2H transmission line.

The coal-retirement portfolios include the additional cost of recovering the remaining investment in the coal units prior to retirement. In addition, resource retirement includes the accelerated decommissioning costs when estimating the resource portfolio costs.

The coal-retirement portfolios also include the cost savings associated with early investment recovery and shutdown. These savings include avoided future capital investments, fixed operating costs, and avoided ROI. Treatment of the fixed-cost accounting is summarized in Table 8.1.

Table 8.1 Fixed-cost impacts of coal retirement

Fixed-Cost Description	Cost Impact
Accelerated recovery of depreciation expense on remaining investments	Cost
Utility rate of return applied over a shorter life	Savings
Accelerated recovery of decommissioning and demolition costs (net of salvage)	Cost
Avoidance of future incremental capital (including avoidance of environmental retrofit investments)	Savings
Avoidance of future fixed operating expenses	Savings

Portfolio Design and Selection

Idaho Power analyzed 23 resource portfolios for the 2015 IRP. All portfolios are designed to balance forecast load with available or additional resources to eliminate energy and capacity deficits according to the IRP planning criteria described in Chapter 7. The energy and capacity deficits for the considered coal-retirement futures are also provided in Chapter 7. The portfolios were designed in collaboration with the IRPAC and public participants in the IRP process.

Status Quo Portfolio

The resource additions in the status quo portfolio are driven by the need to eliminate peak-hour capacity deficits beginning in July 2025 and reaching 523 MW by July 2034. The status quo portfolio is designated as resource portfolio P1.

P1

Table 8.2 Resource portfolio P1

Date	Resource	Installed Capacity	Peak-Hour Capacity
2025	B2H	500 MW transfer capacity April–Sep 200 MW transfer capacity Oct–Mar	500 MW
2034	Reciprocating engines	36 MW	36 MW
		Total retired capacity	(0 MW)
		Total added capacity	536 MW
		Net peak-hour capacity	536 MW

Maintain Coal Capacity Portfolios

Resource additions of the set of portfolios with coal capacity maintained, excepting the planned Boardman shutdown, are driven by capacity deficits beginning in July 2025 and reaching 523 MW by July 2034. These portfolios differ from P1 only in the assumed on-line date for B2H, ranging from 2021 to 2025. The portfolios are designated as resource portfolios P2(a), P2(b), and P2(c).

P2(a)

Table 8.3 Resource portfolio P2(a)

Date	Resource	Installed Capacity	Peak-Hour Capacity
2025	B2H	500 MW transfer capacity April–Sep 200 MW transfer capacity Oct–Mar	500 MW
2034	Reciprocating engines	36 MW	36 MW
		Total retired capacity	(0 MW)
		Total added capacity	536 MW
		Net peak-hour capacity	536 MW

P2(b)

Table 8.4 Resource portfolio P2(b)

Date	Resource	Installed Capacity	Peak-Hour Capacity
2023	B2H	500 MW transfer capacity April–Sep 200 MW transfer capacity Oct–Mar	500 MW
2034	Reciprocating engines	36 MW	36 MW
		Total retired capacity	(0 MW)
		Total added capacity	536 MW
		Net peak-hour capacity	536 MW

P2(c)

Table 8.5 Resource portfolio P2(c)

Date	Resource	Installed Capacity	Peak-Hour Capacity
2021	B2H	500 MW transfer capacity April–Sep 200 MW transfer capacity Oct–Mar	500 MW
2034	Reciprocating engines	36 MW	36 MW
		Total retired capacity	(0 MW)
		Total added capacity	536 MW
		Net peak-hour capacity	536 MW

North Valmy Retirement Year-End 2019 Portfolios

Resource additions for portfolios with North Valmy retirement in 2019 are driven by capacity deficits beginning in July 2020 and reaching 786 MW by July 2034. These resource portfolios are designated as P3, P4(a), P4(b), P4(c), and P5. The P4 portfolios differ primarily in the assumed on-line date for B2H, ranging from 2021 to 2025.

P3

The resource portfolio P3 adds 60 MW of ice-based TES and 330 MW of utility-scale, single-axis PV solar in the early 2020s and the B2H transmission line in 2025. In 2033, 75 MW of additional utility-scale, single-axis PV solar is added. P3 also adds energy efficiency beyond the amount identified as cost-effective in the DSM potential study included in all portfolios. The extra energy efficiency ramps gradually during the IRP planning period, reaching 16 MW of average energy and 24 MW of peak-hour capacity by 2034.

Table 8.6 Resource portfolio P3

Date	Resource	Installed Capacity	Peak-Hour Capacity
2019	Retire North Valmy (both units)	(262 MW)	(262 MW)
2020	Ice-based TES	25 MW	25 MW
2021	Ice-based TES	35 MW	35 MW
2021	Utility-scale solar PV 1-axis	150 MW	77 MW
2023	Utility-scale solar PV 1-axis	180 MW	92 MW
2025	B2H	500 MW transfer capacity April–Sep 200 MW transfer capacity Oct–Mar	500 MW
2033	Utility-scale solar PV 1-axis	75 MW	38 MW
2034	Reciprocating engines	36 MW	36 MW
2020–34	Energy efficiency*	N/A	24 MW
		Total retired capacity	(262 MW)
		Total added capacity	827 MW
		Net peak-hour capacity	550 MW

*Note: Extra energy efficiency is beyond the cost-effective amount determined by the DSM potential study.

P4(a)

The resource portfolio P4(a) adds 60 MW of Vanadium redox flow battery storage and 198 MW of reciprocating engines in the early 2020s prior to the B2H transmission line in 2025. The 60 MW of battery storage are replaced in 2030 to 2031 with new battery storage, followed by the addition of 54 MW of reciprocating engines in 2033.

Table 8.7 Resource portfolio P4(a)

Date	Resource	Installed Capacity	Peak-Hour Capacity
2019	Retire North Valmy (both units)	(262 MW)	(262 MW)
2020	Vanadium redox flow battery storage	25 MW	25 MW
2021	Vanadium redox flow battery storage	35 MW	35 MW
2021	Reciprocating engines	90 MW	90 MW
2023	Reciprocating engines	108 MW	108 MW
2025	B2H	500 MW transfer capacity April–Sep 200 MW transfer capacity Oct–Mar	500 MW
2030	2020 battery storage end of life	(25 MW)	(25 MW)
2030	Vanadium redox flow battery storage (replace)	25 MW	25 MW
2030	2021 battery storage end of life	(35 MW)	(35 MW)
2031	Vanadium redox flow battery storage (replace)	35 MW	35 MW
2033	Reciprocating engines	54 MW	54 MW
		Total retired capacity	(322 MW)
		Total added capacity	872 MW
		Net peak-hour capacity	550 MW

P4(b)

The resource portfolio P4(a) adds 60 MW of Vanadium redox flow battery storage, 90 MW of reciprocating engines in 2020 to 2021, and the B2H transmission line in 2023. The 60 MW of battery storage is replaced in 2030 to 2031 with additional battery storage, followed by the addition of 162 MW of reciprocating engines in 2032 to 2034.

Table 8.8 Resource portfolio P4(b)

Date	Resource	Installed Capacity	Peak-Hour Capacity
2019	Retire North Valmy (both units)	(262 MW)	(262 MW)
2020	Vanadium redox flow battery storage	25 MW	25 MW
2021	Vanadium redox flow battery storage	35 MW	35 MW
2021	Reciprocating engines	90 MW	90 MW
2023	B2H	500 MW transfer capacity April–Sep 200 MW transfer capacity Oct–Mar	500 MW
2030	2020 battery storage end of life	(25 MW)	(25 MW)
2030	Vanadium redox flow battery storage (replace)	25 MW	25 MW
2030	2021 battery storage end of life	(35 MW)	(35 MW)
2031	Vanadium redox flow battery storage (replace)	35 MW	35 MW

Table 8.8 Resource portfolio P4(b) (continued)

Date	Resource	Installed Capacity	Peak-Hour Capacity
2032	Reciprocating engines	54 MW	54 MW
2033	Reciprocating engines	72 MW	72 MW
2034	Reciprocating engines	36 MW	36 MW
		Total retired capacity	(322 MW)
		Total added capacity	872 MW
		Net peak-hour capacity	550 MW

P4(c)

Portfolio P4(c) adds 25 MW of Vanadium redox flow battery storage in 2020 and the B2H transmission line in 2021. The portfolio also includes 35 MW of Vanadium redox flow battery storage added in 2029, with 25 MW of battery storage replacement in 2030. Reciprocating engines totaling 252 MW are added in the early 2030s.

Table 8.9 Resource portfolio P4(c)

Date	Resource	Installed Capacity	Peak-Hour Capacity
2019	Retire North Valmy (both units)	(262 MW)	(262 MW)
2020	Vanadium redox flow battery storage	25 MW	25 MW
2021	B2H	500 MW transfer capacity April–Sep 200 MW transfer capacity Oct–Mar	500 MW
2029	Vanadium redox flow battery storage	35 MW	35 MW
2030	Reciprocating engines	36 MW	36 MW
2030	2020 battery storage end of life	(25 MW)	(25 MW)
2030	Vanadium redox flow battery storage (replace)	25 MW	25 MW
2031	Reciprocating engines	108 MW	108 MW
2033	Reciprocating engines	108 MW	108 MW
		Total retired capacity	(287 MW)
		Total added capacity	837 MW
		Net peak-hour capacity	550 MW

P5

Resource portfolio P5 adds a 300-MW CCCT in 2020 and the B2H transmission line in 2025.

Table 8.10 Resource portfolio P5

Date	Resource	Installed Capacity	Peak-Hour Capacity
2019	Retire North Valmy (both units)	(262 MW)	(262 MW)
2020	CCCT	300 MW	300 MW
2025	B2H	500 MW transfer capacity April–Sep 200 MW transfer capacity Oct–Mar	500 MW
		Total retired capacity	(262 MW)
		Total added capacity	800 MW
		Net peak-hour capacity	538 MW

North Valmy Retirement Year-End 2025 Portfolios

Portfolios with North Valmy retirement in 2025 experience capacity deficits beginning in July 2025 and reaching 786 MW by July 2034. These resource portfolios are designated as P6, P6(b), and P7.

P6

Resource portfolio P6 adds the B2H transmission line in 2025 prior to retiring North Valmy at year-end 2025. A 300-MW CCCT is added in 2030.

Table 8.11 Resource portfolio P6

Date	Resource	Installed Capacity	Peak-Hour Capacity
2025	B2H	500 MW transfer capacity April–Sep 200 MW transfer capacity Oct–Mar	500 MW
2025	Retire North Valmy (both units)	(262 MW)	(262 MW)
2030	CCCT	300 MW	300 MW
		Total retired capacity	(262 MW)
		Total added capacity	800 MW
		Net peak-hour capacity	538 MW

P6(b)

Resource portfolio P6(b) is a variation of P6 that includes in 2030 60 MW of demand response and 20 MW of ice-based TES, allowing the 300-MW CCCT to be deferred by one year to 2031. The 60 MW of demand response is above and beyond the 390 MW of summer demand response included as an existing resource in all portfolios.

Table 8.12 Resource portfolio P6(b)

Date	Resource	Installed Capacity	Peak-Hour Capacity
2025	B2H	500 MW transfer capacity April–Sep 200 MW transfer capacity Oct–Mar	500 MW
2025	Retire North Valmy (both units)	(262 MW)	(262 MW)
2030	Demand response	60 MW	60 MW
2030	Ice-based TES	20 MW	20 MW
2031	CCCT	300 MW	300 MW
		Total retired capacity	(262 MW)
		Total added capacity	880 MW
		Net peak-hour capacity	618 MW

P7

Resource portfolio P7 adds the B2H transmission line in 2025 prior to retiring North Valmy at year-end 2025. A 300 MW pumped-storage hydro project is added in 2030.

Table 8.13 Resource portfolio P7

Date	Resource	Installed Capacity	Peak-Hour Capacity
2025	B2H	500 MW transfer capacity April–Sep 200 MW transfer capacity Oct–Mar	500 MW
2025	Retire North Valmy (both units)	(262 MW)	(262 MW)
2030	Pumped-storage hydro	300 MW	300 MW
		Total retired capacity	(262 MW)
		Total added capacity	800 MW
		Net peak-hour capacity	538 MW

North Valmy Staggered Retirement Year-End 2019 (Unit 1) and Year-End 2025 (Unit 2) Portfolios

Resource additions of portfolios with North Valmy retirement in 2019 (Unit 1) and 2025 (Unit 2) are driven by capacity deficits beginning in July 2021 and reaching 786 MW by July 2034. The portfolios of this set are designated P8 and P9.

P8

Resource portfolio P8 adds 60 MW of ice-based TES and 70 MW of utility-scale, single-axis PV solar in 2021 to 2024 and the B2H transmission line in 2025. P8 adds 45 MW of canal hydro in 2031 and 126 MW of reciprocating engines in 2032 to 2033. Equivalent to resource portfolio P3, portfolio P8 also adds energy efficiency beyond the amount identified as cost-effective in the DSM potential study. The extra energy efficiency ramps gradually during the IRP planning period, reaching 16 MW of average energy and 24 MW of peak-hour capacity by 2034.

Table 8.14 Resource portfolio P8

Date	Resource	Installed Capacity	Peak-Hour Capacity
2019	Retire North Valmy (Unit 1)	(126 MW)	(126 MW)
2021	Ice-based TES	15 MW	15 MW
2023	Ice-based TES	30 MW	30 MW
2024	Utility-scale solar PV 1-axis	70 MW	36 MW
2024	Ice-based TES	15 MW	15 MW
2025	B2H	500 MW transfer capacity April–Sep 200 MW transfer capacity Oct–Mar	500 MW
2025	Retire North Valmy (Unit 2)	(136 MW)	(136 MW)
2031	Canal hydro	45 MW	45 MW
2032	Reciprocating engines	72 MW	72 MW
2033	Reciprocating engines	54 MW	54 MW
2020-34	Energy efficiency*	N/A	24 MW
		Total retired capacity	(262 MW)
		Total added capacity	791 MW
		Net peak-hour capacity	529 MW

*Note: Extra energy efficiency beyond cost-effective amount determined by DSM potential study.

P9

The resource portfolio P9 adds 60 MW of demand response in 2021-24. The 60 MW of demand response is above and beyond the 390 MW of summer demand response included as an existing resource in all portfolios. P9 also adds 54 MW of reciprocating engines in 2024. The B2H transmission line is added in 2025, followed by 18 MW of reciprocating engines in 2031 and a 170-MW SCCT in 2032.

Table 8.15 Resource portfolio P9

Date	Resource	Installed Capacity	Peak-Hour Capacity
2019	Retire North Valmy (Unit 1)	(126 MW)	(126 MW)
2021	Demand response	15 MW	15 MW
2023	Demand response	30 MW	30 MW
2024	Reciprocating engines	54 MW	54 MW
2024	Demand response	15 MW	15 MW
2025	B2H	500 MW transfer capacity April–Sep 200 MW transfer capacity Oct–Mar	500 MW
2025	Retire North Valmy (Unit 2)	(136 MW)	(136 MW)
2031	Reciprocating engines	18 MW	18 MW
2032	SCCT	170 MW	170 MW
		Total retired capacity	(262 MW)
		Total added capacity	802 MW
		Net peak-hour capacity	540 MW

Jim Bridger Staggered Retirement Year-End 2023 (Unit 1) and Year-End 2032 (Unit 2) Portfolios

The resource additions to portfolios with Jim Bridger retirement in 2023 (Unit 1) and 2032 (Unit 2) are driven by peak-hour capacity deficits beginning in July 2024 and reaching 874 MW by July 2034. These resource portfolios are designated as P10 and P11.

P10

The resource portfolio P10 adds a 170-MW SCCT in 2024 and the B2H transmission line in 2025. P10 adds a 300-MW CCCT in 2033.

Table 8.16 Resource portfolio P10

Date	Resource	Installed Capacity	Peak-Hour Capacity
2023	Retire Jim Bridger (Unit 1)	(177 MW)	(177 MW)
2024	SCCT	170 MW	170 MW
2025	B2H	500 MW transfer capacity April–Sep 200 MW transfer capacity Oct–Mar	500 MW
2032	Retire Jim Bridger (Unit 2)	(176 MW)	(176 MW)
2033	CCCT	300 MW	300 MW
		Total retired capacity	(353 MW)
		Total added capacity	970 MW
		Net peak-hour capacity	617 MW

P11

Resource portfolio P11 adds 60 MW of ice-based TES, 155 MW of utility-scale, single-axis PV solar in 2024, and the B2H transmission line in 2025. P11 also adds 180 MW of reciprocating engines and a 45-MW CHP facility in 2033. Like portfolios P3 and P8, P11 also adds energy efficiency beyond the amount identified as cost-effective in the DSM potential study. The extra energy efficiency ramps gradually during the IRP planning period, reaching 16 MW of average energy and 24 MW of peak-hour capacity by 2034.

Table 8.17 Resource portfolio P11

Date	Resource	Installed Capacity	Peak-Hour Capacity
2023	Retire Jim Bridger (Unit 1)	(177 MW)	(177 MW)
2024	Ice-based TES	60 MW	60 MW
2024	Utility-scale solar PV 1-axis	155 MW	80 MW
2025	B2H	500 MW transfer capacity April–Sep 200 MW transfer capacity Oct–Mar	500 MW
2032	Reciprocating engines	108 MW	108 MW
2032	Retire Jim Bridger (Unit 2)	(176 MW)	(176 MW)
2033	CHP	45 MW	45 MW
2033	Reciprocating engines	36 MW	36 MW
2034	Reciprocating engines	36 MW	36 MW
2020-34	Energy efficiency*	N/A	24 MW
		Total retired capacity	(353 MW)
		Total added capacity	889 MW
		Net peak-hour capacity	536 MW

*Note: Extra energy efficiency is beyond the cost-effective amount determined by the DSM potential study.

Jim Bridger Staggered Retirement Year-End 2023 (Unit 1) and Year-End 2028 (Unit 2) Portfolio

The resource additions to portfolios with Jim Bridger retirement in 2023 (Unit 1) and 2028 (Unit 2) are driven by capacity deficits beginning in July 2024 and reaching 874 MW by July 2034. This resource portfolio is designated as P12.

P12

The resource portfolio P12 adds a 170-MW SCCT in 2024 and the B2H transmission line in 2025. P12 also adds a 300-MW CCCT in 2029.

Table 8.18 Resource portfolio P12

Date	Resource	Installed Capacity	Peak-Hour Capacity
2023	Retire Jim Bridger (Unit 1)	(177 MW)	(177 MW)
2024	SCCT	170 MW	170 MW
2025	B2H	500 MW transfer capacity April–Sep 200 MW transfer capacity Oct–Mar	500 MW
2028	Retire Jim Bridger (Unit 2)	(176 MW)	(176 MW)
2029	CCCT	300 MW	300 MW
		Total retired capacity	(353 MW)
		Total added capacity	970 MW
		Net peak-hour capacity	617 MW

Jim Bridger Staggered Retirement Year-End 2023 (Unit 1) and Year-End 2032 (Unit 2), North Valmy Retirement Year-End 2025 Portfolio

The resource additions to the portfolio with Jim Bridger retirement in 2023 (Unit 1) and 2032 (Unit 2), and North Valmy retirement in 2025, are driven by capacity deficits beginning in July 2024 and reaching 1,137 MW by July 2034. This resource portfolio is designated as P13.

P13

Resource portfolio P13 adds a 170-MW SCCT in 2024 and the B2H transmission line in 2025. P13 also adds a 300-MW CCCT in 2029 and a second CCCT in 2033.

Table 8.19 Resource portfolio P13

Date	Resource	Installed Capacity	Peak-Hour Capacity
2023	Retire Jim Bridger (Unit 1)	(177 MW)	(177 MW)
2024	SCCT	170 MW	170 MW
2025	B2H	500 MW transfer capacity April–Sep 200 MW transfer capacity Oct–Mar	500 MW
2025	Retire North Valmy (both units)	(262 MW)	(262 MW)
2029	CCCT	300 MW	300 MW
2032	Retire Jim Bridger (Unit 2)	(176 MW)	(176 MW)
2033	CCCT	300 MW	300 MW
		Total retired capacity	(615 MW)
		Total added capacity	1,270 MW
		Net peak-hour capacity	655 MW

Alternative to B2H Portfolios

This set of four portfolios replaces the B2H transmission line with alternatives. Each B2H alternative portfolio assumes a different coal-retirement future. Resource portfolio P14 assumes coal capacity is maintained. Resource portfolio P15 assumes North Valmy retirement in 2019. Resource portfolio P16 assumes the staggered retirement of North Valmy units 1 and 2 in 2019 and 2025, respectively. Resource portfolio P17 assumes the staggered retirement of Jim Bridger units 1 and 2 in 2023 and 2032, respectively.

P14

Resource portfolio P14 adds 60 MW of ice-based TES in 2025 to 2026, 18 MW of reciprocating engines in 2026, a 300-MW CCCT in 2027, and a 170-MW SCCT in 2032.

Table 8.20 Resource portfolio P14

Date	Resource	Installed Capacity	Peak-Hour Capacity
2025	Ice-based TES	15 MW	15 MW
2026	Ice-based TES	45 MW	45 MW
2026	Reciprocating engines	18 MW	18 MW
2027	CCCT	300 MW	300 MW
2032	SCCT	170 MW	170 MW
		Total retired capacity	(0 MW)
		Total added capacity	548 MW
		Net peak-hour capacity	548 MW

P15

Resource portfolio P15 adds 60 MW of Vanadium redox flow battery storage in 2020 to 2021 and 252 MW of reciprocating engines in 2020 to 2025. P15 also adds a 170-MW SCCT and a 300-MW CCCT in the second half of the 2020s, 60 MW of battery storage replacement, and 36 MW of reciprocating engines in 2034.

Table 8.21 Resource portfolio P15

Date	Resource	Installed Capacity	Peak-Hour Capacity
2019	Retire North Valmy (both units)	(262 MW)	(262 MW)
2020	Vanadium redox flow battery storage	25 MW	25 MW
2021	Vanadium redox flow battery storage	35 MW	35 MW
2021	Reciprocating engines	90 MW	90 MW
2023	Reciprocating engines	108 MW	108 MW
2025	Reciprocating engines	54 MW	54 MW
2026	SCCT	170 MW	170 MW
2029	CCCT	300 MW	300 MW
2030	2020 battery storage end of life	(25 MW)	(25 MW)
2030	Vanadium redox flow battery storage (replace)	25 MW	25 MW
2031	2021 battery storage end of life	(35 MW)	(35 MW)
2031	Vanadium redox flow battery storage (replace)	35 MW	35 MW
2034	Reciprocating engines	36 MW	36 MW
		Total retired capacity	(322 MW)
		Total added capacity	878 MW
		Net peak-hour capacity	556 MW

P16

Resource portfolio P16 adds 60 MW of demand response and 90 MW of reciprocating engines in 2021 to 2025. The 60 MW of demand response is beyond the 390 MW of summer demand

response included as an existing resource in all portfolios. P16 also adds a 300-MW CCCT and a 170-MW SCCT in the second half of the 2020s. In the early 2030s, 18 MW of reciprocating engines and a 170-MW SCCT are added.

Table 8.22 Resource portfolio P16

Date	Resource	Installed Capacity	Peak-Hour Capacity
2019	Retire North Valmy (Unit 1)	(126 MW)	(126 MW)
2021	Demand response	15 MW	15 MW
2023	Demand response	30 MW	30 MW
2024	Demand response	15 MW	15 MW
2024	Reciprocating engines	54 MW	54 MW
2025	Reciprocating engines	36 MW	36 MW
2025	Retire North Valmy (Unit 2)	(136 MW)	(136 MW)
2026	CCCT	300 MW	300 MW
2029	SCCT	170 MW	170 MW
2031	Reciprocating engines	18 MW	18 MW
2032	SCCT	170 MW	170 MW
		Total retired capacity	(262 MW)
		Total added capacity	808 MW
		Net peak-hour capacity	546 MW

P17

Resource portfolio P17 adds a variety of resources, including 250 MW of utility-scale, single-axis solar PV; 162 MW of reciprocating engines; 45 MW of CHP; 30 MW of geothermal; and 60 MW of ice-based TES in 2024 to 2029. In the 2030s, P18 adds a 300-MW CCCT and a 170-MW SCCT.

Table 8.23 Resource portfolio P17

Date	Resource	Installed Capacity	Peak-Hour Capacity
2023	Retire Jim Bridger (Unit 1)	(177 MW)	(177 MW)
2024	Ice-based TES	60 MW	60 MW
2024	Utility-scale solar PV 1-axis	175 MW	90 MW
2025	CHP	45 MW	45 MW
2026	Reciprocating engines	54 MW	54 MW
2027	Geothermal	30 MW	30 MW
2027	Utility-scale solar PV 1-axis	75 MW	38 MW
2028	Reciprocating engines	54 MW	54 MW
2029	Reciprocating engines	54 MW	54 MW
2030	CCCT	300 MW	300 MW
2032	Retire Jim Bridger (Unit 2)	(176 MW)	(176 MW)
2033	SCCT	170 MW	170 MW
		Total retired capacity	(353 MW)
		Total added capacity	895 MW
		Net peak-hour capacity	542 MW

North Valmy Staggered Retirement Year-End 2021 (Unit 1) and Year-End 2025 (Unit 2) Portfolio

After the April 2015 IRPAC meeting, Idaho Power received a submittal requesting the analysis of a portfolio with the retirement of North Valmy Unit 1 in 2021 from IRPAC member David Hawk (Oil and Gas Industry Advisor) in partnership with IRPAC member Ben Otto (Idaho Conservation League). New resources specified by the submittal included B2H, demand response, CHP, small hydro, geothermal, and residential PV solar. Idaho Power developed a resource portfolio using these specifications, adding the retirement of North Valmy Unit 2 in 2025. With the retirement of North Valmy Unit 1 in 2021 and Unit 2 in 2025, capacity deficits begin in July 2022 and reach 786 MW by July 2034. The resulting resource portfolio, designed to meet these deficits and the submitted request for specific resource actions, is designated as resource portfolio P18.

P18

Resource portfolio P18 adds 20 MW of residential PV solar, 60 MW of demand response, a 45-MW CHP facility in 2022 to 2024, and the B2H transmission line in 2025. The 60 MW of demand response is above and beyond the 390 MW of summer demand response included as an existing resource in all portfolios. P18 also adds 3 MW of residential PV solar per year in 2031 to 2034, 40 MW of geothermal in 2031, 45 MW of CHP in 2032, 60 MW of small hydro in 2033, and 18 MW of reciprocating engines in 2034.

Table 8.24 Resource portfolio P18

Date	Resource	Installed Capacity	Peak-Hour Capacity
2021	Retire North Valmy (Unit 1)	(126 MW)	(126 MW)
2022	Residential PV solar	5 MW	2 MW
2022	Demand response	10 MW	10 MW
2023	Residential PV solar	5 MW	2 MW
2023	Demand response	30 MW	30 MW
2024	Residential PV solar	10 MW	3 MW
2024	Demand response	20 MW	20 MW
2024	CHP	45 MW	45 MW
2025	B2H	500 MW transfer capacity April–Sep 200 MW transfer capacity Oct–Mar	500 MW
2025	Retire North Valmy (Unit 2)	(136 MW)	(136 MW)
2031	Residential PV solar	10 MW	3 MW
2031	Geothermal	40 MW	40 MW
2032	Residential PV solar	10 MW	3 MW
2032	CHP	45 MW	45 MW
2033	Residential PV solar	10 MW	3 MW
2033	Small hydro	60 MW	60 MW
2034	Residential PV solar	10 MW	3 MW
2034	Reciprocating engines	18 MW	18 MW
		Total retired capacity	(262 MW)
		Total added capacity	766 MW
		Net peak-hour capacity	504 MW

Portfolio Design Summary

The 23 portfolios analyzed for the 2015 IRP consider a range of alternatives with regard to early coal retirement and the B2H transmission line. The following table provides a summary of the 2015 IRP portfolio scenarios on the basis of early coal retirement and the B2H transmission line.

Table 8.25 Resource portfolio scenario summary

Coal	B2H	Alternative to B2H
No coal capacity retirement	4	1
Early retirement—North Valmy	11	2
Early retirement—Jim Bridger	3	1
Early retirement—North Valmy and Jim Bridger	1	–

This page left blank intentionally.

9. MODELING ANALYSIS AND RESULTS

Idaho Power evaluated the costs of each resource portfolio over the full 20-year planning horizon. The resource portfolio cost is the expected cost to serve customer load using all resources in the portfolio. Portfolio costs are expressed in terms of NPV in the IRP's cost-comparison analysis of portfolios.

The IRP portfolio costs consist of fixed and variable components. The fixed component includes annualized capital costs for new portfolio resources, including transmission interconnection costs for new generating facilities, and fixed O&M costs and ROI. Capital costs for new resources are annualized over the resource's estimated economic life. Annualized capital costs beyond the IRP planning window (2015–2034) are not included in portfolio costs.

Coal-retirement portfolios include costs for the accelerated recovery of remaining depreciation expenses and accelerated recovery of decommissioning and demolition costs (net of salvage). The costs of coal-retirement portfolios are countered by savings from avoiding future coal plant capital upgrades, including environmental retrofit upgrades, and from avoiding future fixed operating expenses and ROI for the retired coal unit(s).

Idaho Power uses the AURORAxmp® (AURORA) electric market model as the primary tool for modeling resource operations and determining operating costs for the 20-year planning horizon. AURORA modeling results provide detailed estimates of wholesale market energy pricing and resource operation and emissions data.

The AURORA software applies economic principles and dispatch simulations to model the relationships between generation, transmission, and demand to forecast market prices. The operation of existing and future resources is based on forecasts of key fundamental elements, such as demand, fuel prices, hydroelectric conditions, and operating characteristics of new resources. Various mathematical algorithms are used in unit dispatch, unit commitment, and regional pool pricing logic. The algorithms simulate the regional electrical system to determine how utility generation and transmission resources operate to serve load.

Multiple electricity markets, zones, and hubs can be modeled using AURORA. Idaho Power models the entire WECC system when evaluating the various resource portfolios for the IRP. A database of WECC data is maintained and regularly updated by the software vendor EPIS, Inc. Prior to starting the IRP analysis, Idaho Power updates the AURORA database based on available information on generation resources within the WECC and calibrates the model to ensure it provides realistic results. Updates to the database generally add additional hourly operational details and move away from flat generation output, de-rates, and fixed-capacity factors. The updates also incorporate detailed generating resource scheduling, which results in a model that is more deterministic in character and provides a more specific operational view of the WECC.

Portfolio costs are calculated as the NPV of the 20-year stream of annualized costs, fixed and variable, for each portfolio. The full set of financial variables used in the analysis is shown in Table 9.1. Each resource portfolio was evaluated using the same set of financial variables.

Table 9.1 Financial assumptions

Plant Operating (Book) Life	30 Years
Discount rate (weighted average capital cost)	6.74%
Composite tax rate	39.10%
Deferred rate	35.00%
General O&M escalation rate	2.20%
Annual property tax escalation rate (% of investment)	0.29%
Property tax escalation rate	3.00%
Annual insurance premium (% of investment)	0.31%
Insurance escalation rate	2.00%
AFUDC rate (annual)	7.75%

CAA Section 111(d) Sensitivity Analysis

Idaho Power developed multiple sensitivities for the EPA's proposed regulation for regulating CO_2 emissions from existing generating sources under CAA Section 111(d). The multiple sensitivities are a reflection of the considerable uncertainty related to the stipulations of the finalized regulation scheduled to be issued in summer 2015. Each sensitivity, with the exception of a null sensitivity in which no restrictions are assumed, is based on a set of assumptions on compliance stipulations for the final regulation. Analyzing multiple sensitivities allows the estimation of a range of possible cost impacts from CAA Section 111(d). The cost sensitivity analysis could provide information to state-level agencies tasked with the development of state plans for CAA Section 111(d) implementation.

The analyzed CAA Section 111(d) sensitivities are described by four categories:

1. Null sensitivity (no CAA Section 111(d))
2. State-by-state mass-based compliance
3. System-wide mass-based compliance
4. Emissions-intensity compliance using the EPA's compliance building blocks

Null Sensitivity (no CAA Section 111(d))

Idaho Power analyzes a null sensitivity to provide a comparison with portfolios complying with regulations on CO_2 emissions for existing power plants. The only portfolio analyzed under the null sensitivity is the status quo portfolio (P1), which maintains coal capacity and meets planning-period deficits with B2H in 2025 and 36 MW of reciprocating engines in 2034.

State-by-State Mass-Based Compliance

Under state-by-state mass-based compliance, CAA Section 111(d) proposed state-specific target reductions are the basis for compliance. The proposed regulation's treatment of Langley Gulch is

uncertain, as it was brought on-line midway through EPA's 2012 baseline year. Consequently, Langley Gulch is assumed to be constrained at one of three possible annual capacity factors: 30 percent (837,018 MWh), 55 percent (1,534,533 MWh), or 70 percent (1,953,042 MWh). The proposed target reductions are defined in Table 9.2.

Table 9.2 Proposed target reductions for state-by-state mass-based compliance (IPC share)

Affected Source	2020–2029 Target MWh	2030 and Beyond Target MWh
Jim Bridger	3,914,502 MWh (13.8% below 2012 MWh)	3,675,608 MWh (19.1% below 2012 MWh)
North Valmy	574,382 MWh (29.5% below 2012 MWh)	533,343 MWh (34.5% below 2012 MWh)
Boardman	149,967 MWh (43.2% below 2012 MWh)	137,029 MWh (48.1% below 2012 MWh)
Langley Gulch	Target 30%, 55%, or 70% annual capacity factor 2020–2034	

System-Wide Mass-Based Compliance

Under system-wide mass-based compliance, CAA Section 111(d) compliance is based on adherence to CO_2 limits imposed at an individual-utility system level. The assumed Idaho Power system-level limits were derived to be consistent with EPA's proposed state-specific target reductions. Under this approach, system-wide emissions, which include emissions from Langley Gulch and Idaho Power's share of Jim Bridger and North Valmy, are constrained to 6,332,020 tons of CO_2 for 2020 to 2029 and to 5,925,874 tons of CO_2 for 2030 and beyond. Compared to 2012 system-wide emissions, these constraint levels are lower by 20 percent (2020 to 2029 constraint) and 25 percent (2030 and beyond constraint).

Emissions-Intensity Compliance Using the EPA's Compliance Building Blocks

In its proposed regulation, the EPA describes building blocks to assist in developing a plan for achieving compliance. Keys to the building-block approach for achieving compliance are the reduction of CO_2 emissions through the re-dispatch of affected sources and the development of renewable energy and energy efficiency resources leading to a reduction in emissions intensity. Idaho Power makes the following assumptions in using the EPA's building blocks as the basis for CAA Section 111(d) compliance:

- Boardman coal plant is reduced to a zero production level and retired by year-end 2020.
- North Valmy coal plant is reduced to a zero production level and retired as early as year-end 2019 or as late as year-end 2025; until retirement, Idaho Power's share of North Valmy is assumed to have an annual production constraint equal to its 2012 production level (IPC share = 814,264 MWh).
- Jim Bridger coal plant is reduced to a production level 53,320 MWh less than its 2012 production level of 4,541,712 MWh (IPC share); the re-dispatch of Jim Bridger is to a new 95-MW CCCT under construction in Wyoming.

- The Langley Gulch natural gas-fired plant is limited to one of three levels based on annual capacity factors of 30 percent (837,018 MWh), 55 percent (1,534,533 MWh), or 70 percent (1,953,042 MWh).

- Renewable energy and energy efficiency resources are developed in Idaho to the EPA's proposed target levels.

Baseline CAA Section 111(d)

Among the sensitivities developed for the 2015 IRP, Idaho Power selected a baseline sensitivity for the initial portfolio cost analysis. The baseline CAA Section 111(d) portfolio cost analysis assumes state-by-state mass-based compliance with Langley Gulch constrained at a 30 percent annual capacity factor. The selection of these assumptions for the baseline analysis is not a reflection of Idaho Power's preference for CAA Section 111(d), nor is it an indication of the company's view of the most probable CAA Section 111(d) outcome. Rather, it is selected to provide information in comparing costs between portfolios. The baseline costs identify portfolios for further analysis under other CAA Section 111(d) sensitivities and for the stochastic risk analysis. The results of the baseline CAA Section 111(d) sensitivity analyses are provided in Table 9.3.

Table 9.3 2015 IRP portfolios, NPV years 2015–2034 ($ thousands) (portfolios in green were studied in the stochastic risk analysis)

Portfolio[1]				Variable Costs	Fixed Costs[3]	Summary		
Portfolio Index (1)	Portfolio Description (2)	B2H (3)	Coal Capacity Retirement (4)	Operating[2] (AURORA) (5)	Total Fixed Costs (6)	Total Fixed + Variable Costs (7) (7) = (5) + (6)	Lowest Cost Rank (8)	Lowest Cost Relative Difference (9)
P1	Status quo w/ B2H_25, recips, (no coal capacity retirement & no CAA Section 111(d) restrictions)	✓		$4,306,018	$110,689	$4,416,707	1	$0
P9*	Valmy19_25 w/ DR, recips, B2H_25, SCCT	✓	✓	$4,489,655	$30,933	$4,520,588	2	$103,880
P11*	Bridger23_32 w/ ice TES, PV, B2H_25, CHP, recips, EE accrue by 2034 to 16 aMW & 24 MW	✓	✓	$4,418,783	$130,594	$4,549,377	3	$132,670
P2(a)*	B2H_25, recips, (no coal capacity retirement)	✓		$4,461,356	$110,689	$4,572,046	4	$155,338
P8*	Valmy19_25 w/ ice TES, PV, B2H_25, hydro, recips, EE accrue by 2034 to 16 aMW & 24 MW	✓	✓	$4,445,028	$129,423	$4,574,450	5	$157,743
P10*	Bridger23_32 w/ SCCT, B2H_25, CCCT	✓	✓	$4,505,955	$75,219	$4,581,175	6	$164,467
P2(b)	B2H_23, recips, (no coal capacity retirement)	✓		$4,456,215	$136,570	$4,592,785	7	$176,078
P6(b)*	Valmy25_25 w/B2H_25, DR, ice TES, CCCT	✓	✓	$4,492,228	$102,944	$4,595,171	8	$178,464
P6	Valmy25_25 w/ B2H_25, CCCT	✓	✓	$4,492,934	$111,303	$4,604,237	9	$187,529
P13*	Bridger23_32 & Valmy25_25 w/ SCCT, B2H_25, CCCT	✓	✓	$4,507,342	$100,935	$4,608,277	10	$191,570
P2(c)	B2H_21, recips, (no coal capacity retirement)	✓		$4,452,737	$164,124	$4,616,861	11	$200,154
P3*	Valmy19_19 w/ ice TES, PV, B2H_25, EE accrue by 2034 to 16 aMW & 24 MW	✓	✓	$4,311,661	$309,467	$4,621,128	12	$204,421
P12	Bridger23_28 w/ SCCT, B2H_25, CCCT	✓	✓	$4,541,071	$100,730	$4,641,800	13	$225,093
P18*	Valmy 21_25 w/ res PV, B2H_25, CHP, geotherm, hydro, recips	✓	✓	$4,464,898	$179,429	$4,644,327	14	$227,619
P4(c)	Valmy19_19 w/ battery, recips, B2H_21	✓	✓	$4,539,309	$105,904	$4,645,213	15	$228,506
P4(b)	Valmy19_19 w/ battery, recips, B2H_23	✓	✓	$4,528,608	$180,442	$4,709,050	16	$292,343
P4(a)	Valmy19_19 w/ battery, recips, B2H_25	✓	✓	$4,521,759	$188,424	$4,710,183	17	$293,475
P17*	Bridger23_32 w/ ice TES, PV, CHP, recips, geothermal, CCCT, SCCT		✓	$4,380,138	$332,652	$4,712,790	18	$296,083
P16*	Valmy19_25 w/ DR, recips, CCCT, SCCT		✓	$4,518,985	$197,652	$4,716,637	19	$299,930
P14	Ice TES, recips, CCCT, SCCT, (no coal capacity retirement)			$4,477,547	$263,236	$4,740,783	20	$324,075
P5	Valmy19_19 w/ CCCT, B2H_25	✓	✓	$4,482,891	$281,412	$4,764,303	21	$347,595
P15	Valmy19_19 w/ battery, recips, SCCT, CCCT		✓	$4,493,671	$311,829	$4,805,500	22	$388,793
P7	Valmy25_25 w/ B2H_25, pumped storage	✓	✓	$4,509,228	$487,899	$4,997,127	23	$580,419

Notes:

[1] All portfolios assume CAA Section 111(d) implementation except for P1.

[2] AURORA simulates the variable fuel and O&M costs and REC sales (when applicable). This includes the existing system, the effects of coal plant shutdowns (when applicable), plus the new portfolio resources and compliance with CAA Section 111(d) (when applicable). The reservation charge for new and existing natural gas plants is calculated in AURORA.

[3] Fixed costs of existing resources are excluded except as needed in accounting for coal-retirement portfolios.

* Denotes portfolios that were studied in the stochastic risk analysis

The selection of portfolios for further analysis indicated in Table 9.3 is based on the results of the baseline CAA Section 111(d) analyses as well as discussions held at IRPAC meetings in which participants voiced a desire to further analyze a relatively broad spectrum of portfolio types (e.g., portfolios with and without B2H).

CAA Section 111(d) Sensitivity Analysis Results

The analysis of portfolio costs under the different CAA Section 111(d) sensitivities indicates that portfolio relative performance does not change significantly across the sensitivities; low-cost portfolios under the baseline CAA Section 111(d) sensitivity tend to have low costs under the other sensitivities. Cost impacts of CAA Section 111(d) are greatest when individual coal-plant dispatch decisions are mandated under a state-by-state approach. Likewise, the more severely Langley Gulch generation is reduced, the higher the cost of compliance. Cost impacts are least when the EPA's building blocks are the basis for CAA Section 111(d) compliance and Langley Gulch is assumed to be permitted to run up to a capacity factor of 70 percent (approximately 1.95 million MWh annually). Under the building block approach, Idaho Power assumes North Valmy can be operated at 2012 production levels (annually) until retirement and Jim Bridger can be operated at annual production levels 53,320 MWh less than 2012 production levels. For reference, P1 costs under the null sensitivity are $4,417 million. Table 9.4 provides the results of the CAA Section 111(d) sensitivity analysis.

Table 9.4 Portfolio costs by CAA Section 111(d) sensitivity ($ millions)

		State-by-State Mass-Based Compliance			System-Wide Mass-Based Compliance	Emissions-Intensity Compliance with Building Blocks		
Portfolio	**Portfolio Description**	**Langley Gulch at 30% Annual CF***	**Langley Gulch at 55% Annual CF**	**Langley Gulch at 70% Annual CF**		**Langley Gulch at 30% Annual CF**	**Langley Gulch at 55% Annual CF**	**Langley Gulch at 70% Annual CF**
P1	Status quo w/ B2H_25, recips, (no coal capacity retirement & no CAA Section 111(d) restrictions)	Status Quo—No CAA Section 111(d)	Status Quo—No CAA Section 111(d)	Status Quo—No CAA Section 111(d)	Status Quo—No CAA Section 111(d)	Status Quo—No CAA Section 111(d)	Status Quo—No CAA Section 111(d)	Status Quo—No CAA Section 111(d)
P2(a)	B2H_25, recips, (no coal capacity retirement)	$4,572	$4,541	$4,536	$4,518	N/A	N/A	N/A
P2(b)	B2H_23, recips, (no coal capacity retirement)	$4,593	$4,563	$4,557	$4,539	N/A	N/A	N/A
P2(c)	B2H_21, recips, (no coal capacity retirement)	$4,617	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High	N/A	N/A	N/A
P3	Valmy19_19 w/ ice TES, PV, B2H_25, EE accrue by 2034 to 16 aMW & 24 MW	$4,621	$4,563	$4,558	$4,512	$4,518	$4,490	$4,488
P4(a)	Valmy19_19 w/ battery, recips, B2H_25	$4,710	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High
P4(b)	Valmy19_19 w/ battery, recips, B2H_23	$4,709	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High
P4(c)	Valmy19_19 w/ battery, recips, B2H_21	$4,645	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High
P5	Valmy19_19 w/ CCCT, B2H_25	$4,764	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High
P6	Valmy25_25 w/ B2H_25, CCCT	$4,604	$4,571	$4,568	$4,536	$4,517	$4,485	$4,480
P6(b)	Valmy25_25 w/B2H_25, DR, ice TES, CCCT	$4,595	$4,564	$4,561	$4,527	$4,509	$4,478	$4,473
P7	Valmy25_25 w/ B2H_25, pumped storage	$4,997	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High
P8	Valmy19_25 w/ ice TES, PV, B2H_25, hydro, recips, EE accrue by 2034 to 16 aMW & 24 MW	$4,574	$4,541	$4,538	$4,503	$4,485	$4,458	$4,455
P9	Valmy19_25 w/ DR, recips, B2H_25, SCCT	$4,521	$4,494	$4,490	$4,455	$4,438	$4,408	$4,410
P10	Bridger23_32 w/ SCCT, B2H_25, CCCT	$4,581	$4,551	$4,545	$4,545	N/A	N/A	N/A

Table 9.4 Portfolio costs by CAA Section 111(d) sensitivity ($ millions) (continued)

		State-by-State Mass-Based Compliance			System-Wide Mass-Based Compliance	Emissions-Intensity Compliance with Building Blocks		
Portfolio	Portfolio Description	Langley Gulch at 30% Annual CF*	Langley Gulch at 55% Annual CF	Langley Gulch at 70% Annual CF		Langley Gulch at 30% Annual CF	Langley Gulch at 55% Annual CF	Langley Gulch at 70% Annual CF
P11	Bridger23_32 w/ ice TES, PV, B2H_25, CHP, recips, EE accrue by 2034 to 16 aMW & 24 MW	$4,549	$4,511	$4,506	$4,510	N/A	N/A	N/A
P12	Bridger23_28 w/ SCCT, B2H_25, CCCT	$4,642	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High	N/A	N/A	N/A
P13	Bridger23_32 & Valmy25_25 w/ SCCT, B2H_25, CCCT	$4,608	$4,577	$4,572	$4,570	$4,535	$4,505	$4,498
P14	Ice TES, recips, CCCT, SCCT, (no coal capacity retirement)	$4,741	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High	N/A	N/A	N/A
P15	Valmy19_19 w/ battery, recips, SCCT, CCCT	$4,806	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High	Baseline Costs too High
P16	Valmy19_25 w/ DR, recips, CCCT, SCCT	$4,717	$4,682	$4,672	$4,530	$4,639	$4,606	$4,600
P17	Bridger23_32 w/ ice TES, PV, CHP, recips, geotherm, CCCT, SCCT	$4,713	$4,657	$4,649	$4,665	N/A	N/A	N/A
P18	Valmy 21_25 w/ res PV, B2H_25, CHP, geotherm, hydro, recips	$4,644	$4,615	$4,610	$4,578	$4,560	$4,533	$4,528

Note: Gray shaded cells not analyzed because no Valmy retirement is assumed (N/A) and/or baseline costs are too high.

* Baseline CAA Section 111(d) sensitivity.

Stochastic Risk Analysis

The stochastic analysis assesses the effect on portfolio costs when select variables take on values different from their planning-case levels. Stochastic variables are selected based on the degree to which there is uncertainty regarding their forecasts and to the degree they can affect the analysis results (i.e., portfolio costs).

Idaho Power identified the following three variables for the stochastic analysis:

1. *Natural gas price*—Natural gas prices follow a log-normal distribution centered on the planning case forecast. Natural gas prices are serial correlated, and the serial correlation is based on the historic year-to-year correlation from 1990 through 2014. The serial correlation factor is 0.65.

2. *Customer load*—Customer load follows a normal distribution and is correlated with Pacific Northwest regional load. Idaho Power worked with the Northwest Power and Conservation Council (NWPCC) as part of research conducted for the 2013 IRP to estimate the correlation between Idaho Power customer load and regional customer load. The correlation factor is 0.50.

3. *Hydroelectric variability*—Hydroelectric variability follows a normal distribution. Idaho Power-owned hydroelectric generation is correlated with the Pacific Northwest regional hydroelectric generation, and the correlation factor is 0.70. This correlation was derived using historical streamflow data from 1928 through 2009.

The three selected stochastic variables are key drivers of variability in year-to-year power supply costs and therefore provide suitable stochastic shocks to allow differentiated results for analysis.

The stochastic analysis was performed under the system-wide mass-based limits on CO_2 emissions. This assumption was selected because all eleven portfolios can comply with CAA Section 111(d) under this compliance approach. Moreover, the objective of the stochastic analysis is to determine the cost impact when portfolios are stochastically shocked. The purpose of the analysis is to understand the range of portfolio costs across the full extent of stochastic shocks (i.e., across the full set of stochastic iterations), and how the ranges for portfolios differ.

Idaho Power created a set of 100 iterations based on the three stochastic variables. Idaho Power then calculated the portfolio cost for eleven portfolios, where the eleven portfolios were selected based on results of the initial cost analysis under the baseline CAA Section 111(d) sensitivity or to provide a wide range of resource types (e.g., with and without B2H). Each stochastic iteration was reduced to one numerical value—the NPV of the total cost to serve customer load over the 20-year planning period. Figure 9.1 shows the stochastic analysis results.

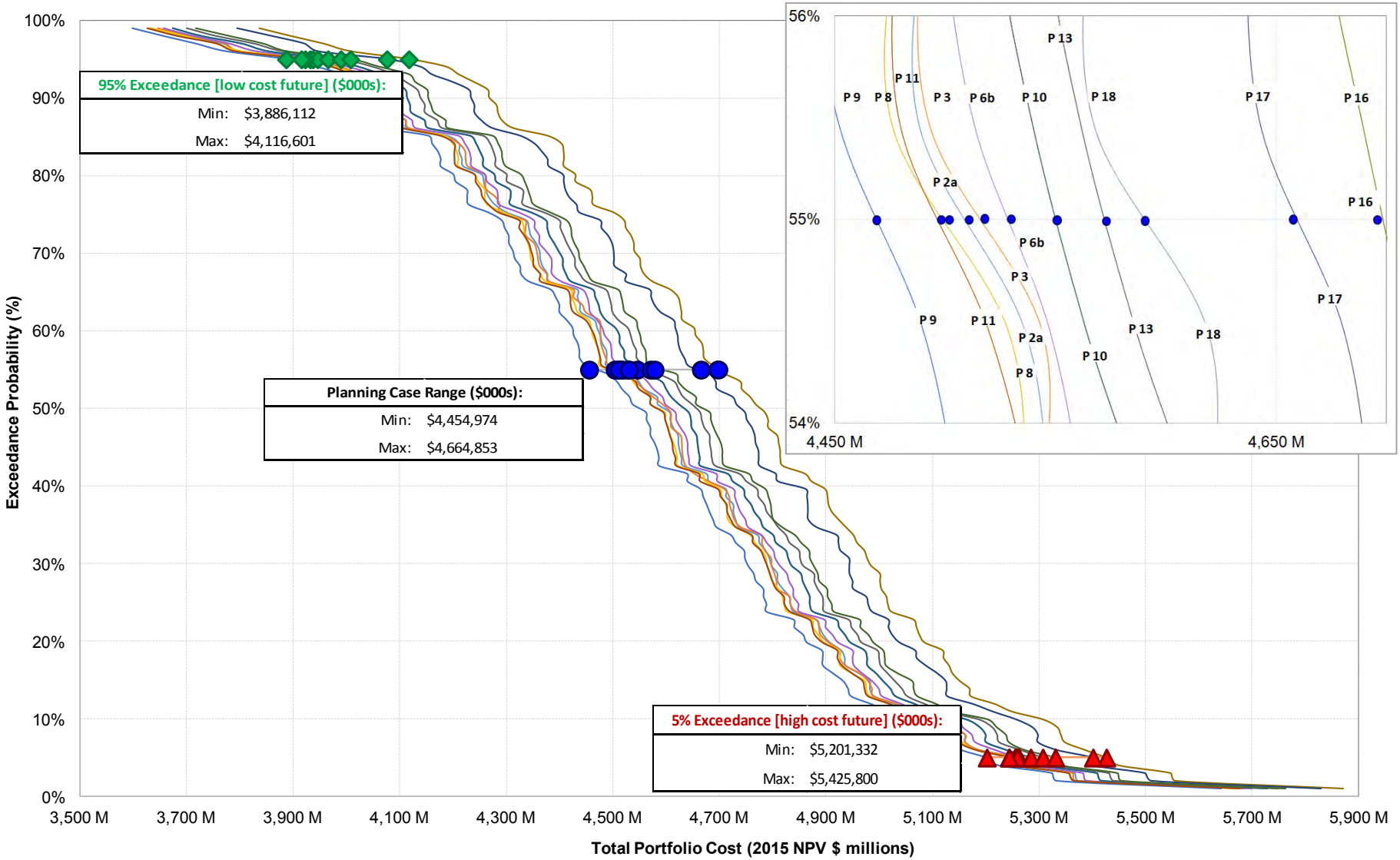


Figure 9.1 Portfolio stochastic analysis

In Figure 9.1, the horizontal axis is the portfolio cost (NPV) and the vertical axis is the exceedance probability. Each line on the figure corresponds to one of the eleven portfolios stochastically analyzed, and the line is the connection of ranked NPV observations for the 100 stochastic iterations. The figure illustrates portfolio costs at the 5-percent and 95-percent exceedance probabilities, as well as portfolio costs with planning case inputs for the three stochastic variables (natural gas, customer load, hydro condition). Reassuringly, the planning case results approximate well the 50-percent exceedance level.

Figure 9.1 illustrates portfolio P9, a North Valmy early retirement portfolio with B2H, is the least-cost portfolio for the full set of 100 iterations. Portfolios are relatively clustered across the top nine least-cost portfolios, with B2H alternative portfolios P16 and P17 somewhat set apart with higher costs.

While not easily discerned, there is some crossing of the portfolio-specific lines in Figure 9.1. Significant crossing of lines in the exceedance graph is an indication of substantial portfolio disparity; portfolio cost performance in this case is markedly different across the set of stochastic iterations. As an example, a portfolio consisting of exclusively natural gas-fired generation would be expected to conspicuously cross lines on Figure 9.1 as portfolio costs range greatly from low to high natural gas-price futures. Finally, the lack of significant crossing of lines is a testament to the resource diversity of Idaho Power's existing portfolio and the portfolios of new resources considered in the IRP; under no set of stochastic futures is a portfolio a clear and runaway cost winner, only to be countered by a different set of futures for which it is just as clearly a losing portfolio susceptible to significantly higher costs than other portfolios.

Portfolio Cost-Assessment of Year-to-Year Variability

At the request of participants in the IRPAC process, Idaho Power expanded the stochastic analysis for the 2015 IRP to include an assessment of year-to-year portfolio cost variability. This assessment of year-to-year variability allows portfolios to be compared on the basis of their susceptibility to large year-to-year price swings. Idaho Power assesses the year-to-year variability by use of the standard deviation metric. For each stochastic iteration, the standard deviation of the 20-year stream of AURORA-determined variable costs (converted to base 2015 dollars) is calculated. Therefore, each of the eleven portfolios for which stochastic analysis is performed has 100 standard deviation measures corresponding to the 100 different stochastic iterations. Portfolios susceptible to large year-to-year price swings tend to have larger standard deviations.

An exceedance graph of the standard deviations for each of the eleven portfolios is shown as Figure 9.2. The exceedance graph indicates that P3, which adds just over 400 MW of utility-scale PV solar, is the least susceptible to large year-to-year swings. Portfolio P16, which adds more than 700 MW of natural gas-fired generating capacity, is the most susceptible to large year-to-year swings.

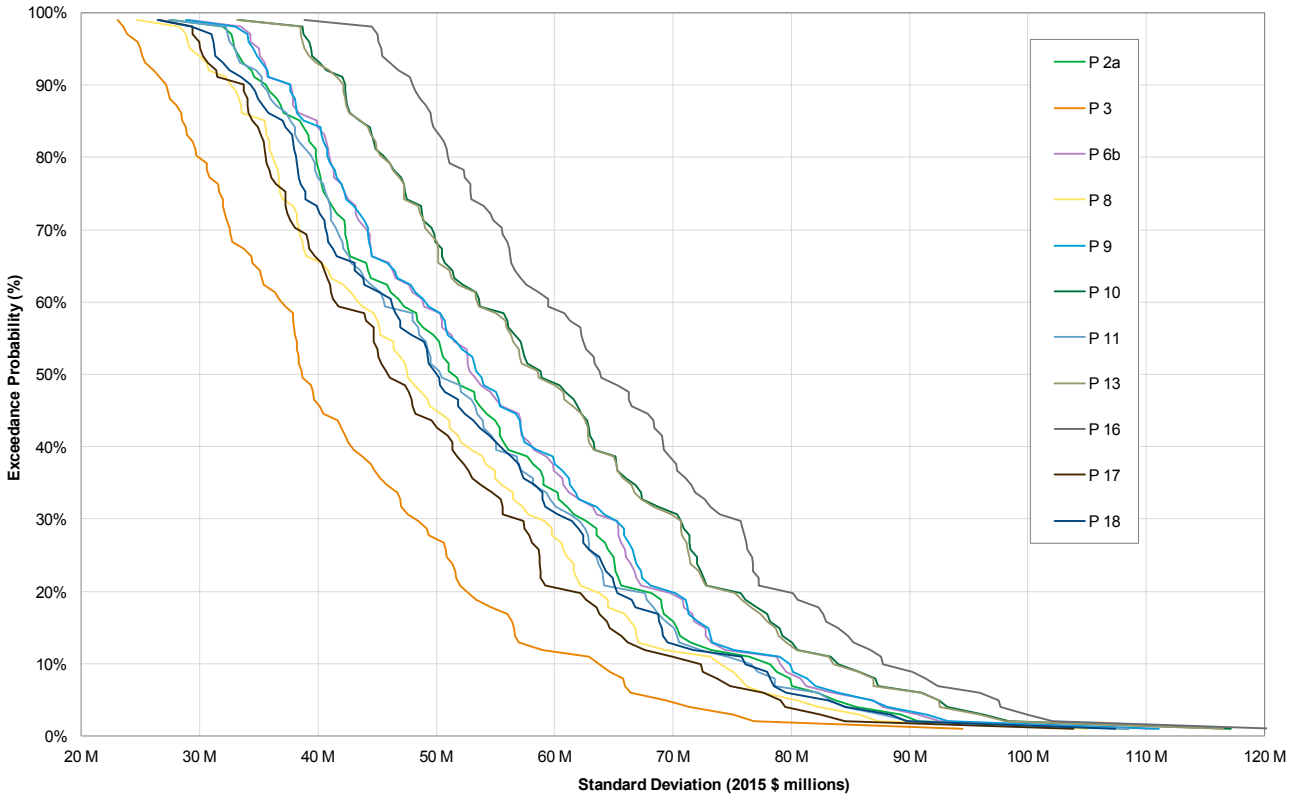


Figure 9.2 Exceedance graph of standard deviations

Tipping-Point Analysis

To test the sensitivity of total portfolio cost to capital-cost estimates, Idaho Power conducted a tipping-point analysis for P3, which has a high penetration of utility-scale, single-axis PV solar, and P7, which has 300 MW of pumped-storage hydro. In the tipping-point analysis, the change in the total portfolio cost is determined as a function of change in the capital cost. The capital cost of the solar resource is varied for P3, and the capital cost of pumped-storage hydro is varied for P7. The percent change in the capital cost is relative to planning-case capital-cost estimates, where the solar resource under the planning case is estimated at $1,250 per kW (for capacity constructed in 2017 or later) and pumped-storage hydro is estimated at $5,000 per kW. A graph of the tipping-point analysis results is provided in Figure 9.3. As an example, the graph illustrates that a change in utility-scale, single-axis PV solar of -30 percent results in an estimated decrease in total portfolio costs for P3 of $50 million (NPV).

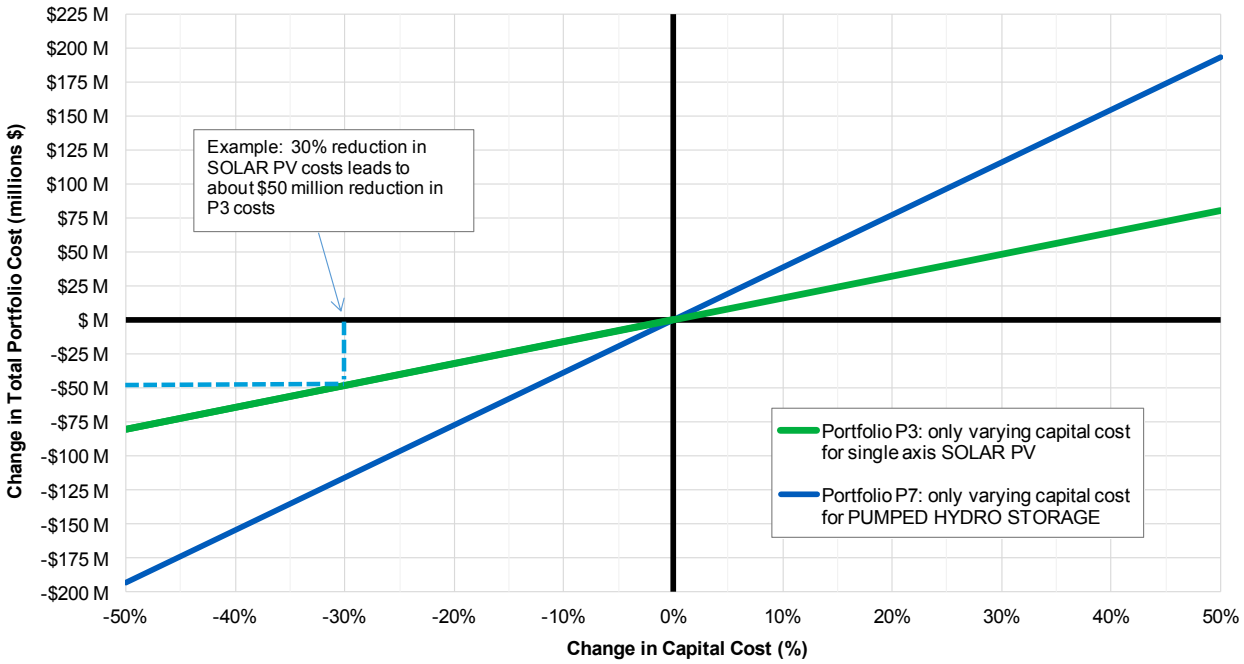


Figure 9.3 Tipping-point analysis results

Portfolio Emissions

For the 2015 IRP, Idaho Power analyzed the total portfolio emissions for the 20-year planning period by the following four emission types:

1. CO_2—A greenhouse gas associated with climate change
2. NO_x—Contributes to regional haze
3. SO_2—Contributes to acid rain formation
4. Hg—A toxic element found in coal deposits

Total emissions by type were calculated using AURORA emissions modeling. The total emissions for each portfolio include emissions from new resources in addition to emissions from Idaho Power's existing resources. With the exception of portfolios retiring Jim Bridger units 1 and 2 without installation of NO_x-controlling environmental retrofits, all portfolios comply with environmental regulations. Illustrations of the four emission types for the eleven portfolios on which CAA Section 111(d) sensitivity and stochastic analyses were performed are provided in *Appendix C—Technical Appendix.*

Qualitative Risk Analysis

The qualitative risks associated with the portfolios are more difficult to assess. The goal is to select a portfolio likely to withstand unforeseen events. The portfolios contain a diverse range of resource futures. Each future includes existing and new generating resources with different implementation, fuel, and technology risks. The following section highlights specific risks within

the portfolios, describes Idaho Power's interpretation of the risk profiles associated with each resource, and acknowledges that the portfolios may contain unique and differing risks.

Existing Generation

Hydro—Water-Supply Risk

The long-term sustainability of the Snake River Basin streamflows is important for Idaho Power to sustain hydro generation as a resource to meet future demand. Several assumptions related to the management of streamflows were made in developing the 20-year streamflow forecasts for the IRP. These assumptions include the following:

- The implementation of aquifer management practices on the ESPA, including aquifer recharge, system conversions, and the CREP
- Future irrigation demand and return flows
- Declines in reach gains tributary to the Snake River
- Expansion of weather-modification efforts (i.e., cloud seeding).

The assumptions used in developing the 20-year streamflow forecast are carefully planned and based on the current knowledge of Idaho Power staff in consultation with other stakeholders. Those assumptions are also subject to the limitations of the current models used in developing the twenty-year streamflow forecast for the 2015 IRP.

Additional risks to future hydro generation not included in the development of the 20-year streamflow outlook consist of the following:

- Changes in the timing and demand for irrigation water due to climate variability
- Changes to the sources of flow augmentation water and the potential for overestimation of flow augmentation availability in low-water years
- Long-term changes in the timing of flood control releases at Brownlee Reservoir in response to earlier snowmelt
- The potential for underestimation of the decline in reach gains within the Snake River Basin
- Changes to funding or the ability to achieve forecasted levels of aquifer management on the ESPA.

Relicensing Risk

Working within the constraints of the original FERC licenses, the HCC has historically provided operational flexibility that has benefited Idaho Power's customers. The operational flexibility of the HCC is increasingly critical to the successful integration of variable energy resources. 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 optimally manage the HCC, making the integration of variable energy resources more challenging and ultimately increasing power supply costs.

Fossil Fuel-Fired Power Generation and Proposed CAA Section 111(d) Regulation Risks

In 2014, the EPA released, under CAA Section 111(d), a proposed regulation for addressing greenhouse gas emissions from existing fossil fuel-fired electric generating units. The EPA's proposal requires states meet their goal by 2030, with interim goals from 2020 to 2029. The EPA stated it expects to finalize the rulemaking by summer 2015. State implementation plans would be due by June 20, 2016, subject to extensions for portions of the plan to June 30, 2017, for state plans or June 20, 2018, for multi-state plans, under certain circumstances. Since this is a proposed regulation, it is subject to interpretation and change. There is considerable uncertainty on the stipulations of the final regulation, and the resulting impact on fossil fuel-fired generation on Idaho Power's system and throughout the region.

Regulatory risk

Idaho Power is a regulated utility with an obligation to serve customer load in its service area and is therefore subject to regulatory risk. Idaho Power expects that future resource additions and removals will be approved for inclusion in the rate base and that it will be allowed to earn a fair rate of ROIs related to resource actions of the IRP portfolios. Idaho Power includes public involvement in the IRP process through an IRPAC and by opening the IRPAC 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 and removals when the plan is submitted for approval. The open public process reduces the regulatory risk associated with developing a resource plan.

NO_x Compliance Alternatives Risk

Portfolios with the early retirement of Jim Bridger units 1 and 2 assume these units are permitted to operate until retirement without installation of SCR retrofits necessary for compliance with EPA regional haze regulations. All other portfolios assume the SCR retrofits are installed on schedule in 2021 for Unit 2 and 2022 for Unit 1. The permitting associated with the Jim Bridger early retirement compliance alternatives is highly speculative at this point. An inability to successfully achieve permitting consistent with the assumptions of these compliance alternatives would likely have a significant effect on the costs and feasibility of portfolios with the early retirement of Jim Bridger units 1 and 2.

New Generation

Resource Commitment Risk

Idaho Power 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, including the pace of PURPA resource development, siting issues, partnership influences, and the performance of existing resources.

PURPA Development

In the IRP's assessment of resource adequacy, Idaho Power assumes PURPA projects having signed contracts are part of system resources. The forecast of PURPA development is a unique challenge in the IRP's assessment of resource adequacy; PURPA development occurs independent of the IRP process and can abruptly alter resource adequacy. Idaho Power's practice is to include PURPA projects that are operational or under signed contract.

Since the 2015 IRP process began in late summer 2014, Idaho Power signed contracts for 461 MW of solar PURPA projects and has received inquiries for an additional 885 MW. Since including the 461 MW of solar contracts as part of committed system resources in the 2015 IRP, contracts for four solar PURPA projects totaling 141 MW have been terminated, leaving 320 MW still under contract. Table 9.5 illustrates the effect of removing the 141 MW of solar PURPA projects with terminated contracts on the 2015 IRP first deficit year.

Table 9.5 First peak-hour capacity deficit effects of removing 141 MW of solar PURPA

Scenario	First deficit 2015 IRP	First deficit without 141 MW solar PURPA
Status quo	July 2025	July 2024
Maintain coal capacity	July 2025	July 2024
North Valmy retire units 1 and 2 year-end 2019	July 2020	July 2020
North Valmy retire units 1 and 2 year-end 2025	July 2025	July 2024
North Valmy retire Unit 1 year-end 2019 and Unit 2 year-end 2025	July 2021	July 2021
North Valmy retire Unit 1 year-end 2021 and Unit 2 year-end 2025	July 2022	July 2022
Jim Bridger retire Unit 1 year-end 2023 and Unit 2 year-end 2028	July 2024	July 2024
Jim Bridger retire Unit 1 year-end 2023 and Unit 2 year-end 2032	July 2024	July 2024
Jim Bridger retire Unit 1 year-end 2023 and Unit 2 year-end 2032, North Valmy retire units 1 and 2 year-end 2025	July 2024	July 2024

As unbuilt resources, uncertainty persists in relation to the remaining 320 MW of solar PURPA projects. Further contract terminations will lead to earlier onsets of system deficiencies and may ultimately require Idaho Power to construct system resources earlier than expected and with larger capacities.

While uncertainty related to the potential over-forecasting of PURPA development is a critical risk element from the perspective of resource adequacy, PURPA development also carries the potential for under-forecasting. The potential for under-forecasting is evidenced by the October 13, 2014, filing of signed contracts for 401 MW of solar PURPA projects, out of the 461 MW in total; over the course of a day, the PURPA forecast grew by 401 MW. While under-forecasting does not jeopardize system resource adequacy, it does increase the likelihood that Idaho Power will encounter issues associated with energy oversupply during system operations. Issues associated with periodic energy oversupply have grown increasingly frequent over recent years. The expansion of variable and intermittent generation will increase this reliability challenge. The flexible-resource needs assessment performed for the 2015 IRP

corroborates concerns related to reliability impacts from periodic energy oversupply. The flexible resource needs assessment is described later in this chapter.

Boardman to Hemingway transmission line

Significant challenges have been encountered during the permitting phase of the B2H transmission line. Environmental requirements related to siting of the transmission line have the potential to delay the project and increase permitting costs. The completion date of the project is subject to these siting, permitting, and regulatory approval requirements. The needs of the partners, PacifiCorp and BPA, also impact the in-service date.

Regional Resource Adequacy

Regional resource adequacy is part of the regional transmission planning process. In July 2013, the NWPCC approved a charter for the Resource Adequacy Advisory Committee (RAAC). The RAAC's purpose is to assess power supply adequacy in the Northwest. Idaho Power has participated in the RAAC since its inception and also in the NWPCC's Resource Adequacy Forum, which preceded the RAAC.

The NWPCC adopted an adequacy standard used by the RAAC as a metric for assessing resource adequacy. The purpose of the resource adequacy standard is to provide an early warning should resource development fail to keep pace with demand growth. The analytical information generated with each resource adequacy assessment assists the regional utilities when preparing their individual IRPs. The statistic used to assess compliance with the adequacy standard is the likelihood of supply shortage, which is commonly known as the loss of load probability (LOLP). Under the adequacy standard, the LOLP is held to a maximum level of 5 percent.

The RAAC issued a draft report on an assessment of LOLP for the 2020 and 2021 operating years. The LOLP for the 2020 operating year is just under the 5 percent adequacy standard level. For the 2021 operating year, the LOLP increases to a little over 8 percent. The draft RAAC report indicates the increased LOLP for the 2021 operating year is the result of planned retirements of coal-fired generating capacity at Centralia, Washington, and the Boardman power plant. The RAAC adequacy assessment notes that the 2021 LOLP would be brought to below the 5 percent level by adding resources providing the equivalent of 1,150 MW of dispatchable generation. The RAAC also notes the LOLP analysis for both operating years does not include planned, new generating resources in the region, because these resources, while planned, have not yet been sited or licensed.

In general, the Pacific Northwest experiences peak energy demand in the winter, whereas Idaho Power experiences peak demand in the summer. The 2015 IRP analysis indicates Idaho Power resource deficits occur in the summer months, with July being the most critical month. The Northwest Regional Adequacy Assessment indicates that January, February, and to a lesser extent August are the most critical months for the overall Pacific Northwest region. The B2H transmission line is a regional resource that will assist Idaho Power and the larger Pacific Northwest in addressing their opposing seasonal capacity deficits.

The Idaho Power resource planning process is consistent with the NWPCC resource adequacy studies. The Idaho Power stochastic analysis indicates that even under high load,

high electricity/natural gas prices, and low water conditions, resource portfolios containing B2H are the lowest-cost portfolios.

DSM implementation

While Idaho Power has considerable experience in DSM programs, there is always an implementation risk with a new program. The actual energy savings and peak reductions may vary significantly from the estimated amounts if customer participation rates are not achieved.

New technologies

Many of the portfolios include technologies Idaho Power has limited experience in developing, building, or operating. This lack of direct experience increases the risk associated with the development of these resources, including the following:

- **Price Risk**: Cost estimates for solar are based on a 2014 Lazard report. While this report provides an objective, third-party estimate of resource costs, there is risk that trends in solar pricing may not be properly captured by the Lazard report.
- **Siting Risk**: Several of the technologies involve different risks associated with the type of resource being developed:
  - Fuel types, such as gas, may encounter public and political pressure against a project being located near load centers or being constructed at all.
  - Technologies, such as CHP and ice-based TES, would require a large commercial or industrial customer to partner with Idaho Power.

Geothermal, pumped storage, and canal drop hydro require the facility to be sited at the source of the motive force. These projects are often located in remote locations far from load centers, which increase the development and transmission costs associated with the resource.

Preferred Portfolio

On the basis of the 2015 IRP's quantitative and qualitative analysis, the preferred portfolio selected by Idaho Power is P6(b). P6(b) balances the cost, risk, and environmental concerns identified in this IRP. The retirement of the North Valmy plant and the completion of B2H in 2025 balances the risks of CAA Section 111(d), increases in unplanned intermittent and variable generation, and is shown to be cost competitive. P6(b) also includes the addition of 60 MW of demand response and 20 MW of ice-based TES in 2030. In 2031, P6(b) also adds a 300-MW CCCT. These resource additions late in the planning period address projected needs for resources providing peaking capability and system flexibility. With expected long-term expansion of variable energy resources, the need for dispatchable resources that provide system flexibility will also increase.

Analysis of Shoshone Falls Upgrade

For the 2015 IRP, Idaho Power analyzed the benefits and costs of the 50-MW expansion of the Shoshone Falls Power Plant. The incremental electrical generation the plant would produce with

the expansion is, on average, approximately 200 GWh annually. Using the AUROA model, an analysis was performed to determine the value this incremental hydro generation would provide to the system. The incremental generation is assumed to be eligible for RECs and the value of these certificates is included in the benefit calculation. The cost of the project was updated using 2015 IRP assumptions.

The analysis indicates that over the 20-year planning period, the incremental energy produced from the expansion is projected to yield a benefit to the preferred portfolio of approximately $13.8 million on an NPV basis under planning-case assumptions for natural gas price, customer load, and hydroelectric generation. However, as noted in Chapter 5, nearly 75 percent of the incremental energy in an average year will be produced during the six-month period from January through June, with substantially less production during July through September. Therefore, while the analysis indicates some economic benefit from the incremental energy, the 50-MW Shoshone Falls expansion cannot be linked to an IRP-determined resource need, as it provides little to no capacity or energy during peak summer load months.

As a result, Idaho Power will explore the construction of a smaller upgrade to more cost-effectively replace the aging 0.6 MW and 0.4 MW units at Shoshone Falls. The smaller upgrade will allow energy benefits to be realized through a much higher annual capacity factor and fulfill license requirements associated with the beneficial use of streamflow at the project location. Conceptual-level analysis indicates an upgrade having a capacity ranging in size from 1.7 MW to 4.0 MW is well suited for the hydraulic characteristics of the existing facilities. The cost analysis conducted as part of the conceptual-level study indicates energy from the smaller upgrade can be produced at a 40-year levelized cost of approximately $50 to $55 per MWh for the 4-MW upgrade and $60-$65 per MWh for the 1.7-MW upgrade. As indicated in the Action Plan in Chapter 10, Idaho Power will continue to study smaller-upgrade options and seek an amendment of the current FERC license to allow for the construction of a smaller-sized capacity upgrade to commence in 2017.

Capacity Planning Margin

Idaho Power discussed planning criteria with state utility commissions and the public in the early 2000s before adopting the present planning criteria. Idaho Power's future resource requirements are not based directly on the need to meet a specified reserve margin. The company's long-term resource planning is driven instead 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 part of preparing the 2015 IRP, Idaho Power calculated the capacity planning margin resulting from the resource development identified in P6(b), the preferred resource portfolio. When calculating the planning margin, the total resources available to meet demand consist of the additional resources available under the preferred portfolio plus the generation from existing and committed resources, assuming expected-case (50th-percentile) water conditions. The generation from existing resources also includes expected firm purchases from regional markets. The resource total is then compared with the expected-case (50th-percentile) peak-hour load, with the excess resource capacity designated as the planning margin. The calculated planning margin provides an alternative view of the adequacy of the preferred portfolio,

which was formulated to meet more stringent load conditions under less favorable water conditions.

Idaho Power maintains 330 MW of transmission import capacity above the forecast peak load to cover the worst single planning contingency. The worst single planning contingency is defined as an unexpected loss equal to Idaho Power's share of two units at the Jim Bridger coal facility or the loss of Langley Gulch. The reserve level of 330 MW translates into a reserve margin of over 10 percent, and the reserved transmission capacity allows Idaho Power to import energy during an emergency via the NWPP. A 330-MW reserve margin also results in the attainment of a loss-of-load expectation (LOLE) of roughly 1 day in 10 years, a standard industry measurement. Capacity planning margin calculations for July of each year through the planning period are shown in Table 9.6.

Table 9.6 Capacity planning margin

	July 2015	July 2016	July 2017	July 2018	July 2019	July 2020	July 2021	July 2022	July 2023	July 2024	July 2025	July 2026	July 2027	July 2028	July 2029	July 2030	July 2031	July 2032	July 2033	July 2034
Load and Resource Balance																				
Peak-Hour Forecast (50th%)	(2,923)	(3,001)	(3,044)	(3,074)	(3,107)	(3,142)	(3,196)	(3,241)	(3,265)	(3,315)	(3,344)	(3,380)	(3,446)	(3,469)	(3,506)	(3,586)	(3,603)	(3,665)	(3,711)	(3,737)
Existing Resources																				
Coal																				
Boardman	55	55	55	55	55	55	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Jim Bridger	703	703	703	703	703	703	703	703	703	703	703	703	703	703	703	703	703	703	703	703
North Valmy	263	263	263	263	263	263	263	263	263	263	263	–	–	–	–	–	–	–	–	–
Coal Total	1,021	1,021	1,021	1,021	1,021	1,021	966	966	966	966	966	703	703	703	703	703	703	703	703	703
Gas																				
Langley Gulch	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300	300
Gas Peakers	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416	416
Gas Total	716	716	716	716	716	716	716	716	716	716	716	716	716	716	716	716	716	716	716	716
Hydroelectric																				
Hydroelectric (50th%)—HCC	1,192	1,194	1,199	1,199	1,202	1,199	1,196	1,193	1,190	1,187	1,184	1,181	1,178	1,175	1,172	1,169	1,167	1,164	1,161	1,158
Hydroelectric (50th%)—Other	295	295	295	295	295	295	294	293	293	292	291	290	289	289	288	287	287	286	285	284
Hydroelectric Total (50th%)	1,487	1,488	1,493	1,493	1,497	1,494	1,490	1,486	1,482	1,479	1,475	1,471	1,467	1,464	1,460	1,457	1,453	1,450	1,446	1,442
CSPP (PURPA) Total	156	220	405	405	405	405	405	405	405	405	405	404	404	404	401	400	390	389	380	380
PPAs																				
Elkhorn Valley Wind	5	5	5	5	5	5	5	5	5	5	5	5	5	–	–	–	–	–	–	–
Raft River Geothermal	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Neal Hot Springs Geothermal	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Clatskanie Exchange—Take	10	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Clatskanie Exchange—Return	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
PPAs Total	33	23	23	23	23	23	23	23	23	23	23	23	23	18	18	18	18	18	18	18

Table 9.6 Capacity planning margin (continued)

	July 2015	July 2016	July 2017	July 2018	July 2019	July 2020	July 2021	July 2022	July 2023	July 2024	July 2025	July 2026	July 2027	July 2028	July 2029	July 2030	July 2031	July 2032	July 2033	July 2034
Firm Pacific Northwest Import Capability Total	243	243	239	234	230	227	224	273	270	266	261	257	254	249	245	242	238	234	230	230
Existing Resource Subtotal	3,656	3,711	3,897	3,892	3,892	3,886	3,824	3,869	3,862	3,854	3,846	3,574	3,567	3,554	3,544	3,535	3,518	3,510	3,493	3,489
Monthly Surplus/Deficit	733	710	853	818	785	743	628	628	597	540	501	194	121	85	38	(51)	(84)	(156)	(218)	(248)
2013 IRP Resources																				
2025 B2H	–	–	–	–	–	–	–	–	–	–	500	500	500	500	500	500	500	500	500	500
2030 Demand Response	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	60	60	60	60	60
2030 Ice-Based TES	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	20	20	20	20	20
2031 CCT	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–	300	300	300	300
New Resource Subtotal	–	–	–	–	–	–	–	–	–	–	500	500	500	500	500	580	880	880	880	880
Remaining Monthly Surplus/Deficit	733	710	853	818	785	743	628	628	597	540	1,001	694	621	585	538	529	796	724	662	632
Planning Margin	25%	24%	28%	27%	25%	24%	20%	19%	18%	16%	30%	21%	18%	17%	15%	15%	22%	20%	18%	17%

Flexible Resource Needs Assessment

Idaho Power analyzed the need for flexible resources as directed by the OPUC in Order 12-013. Idaho Power determined there are adequate flexible resources to address up-regulation (up-regulation is required when intermittent generation is less than the quantity scheduled and Idaho Power generation must overcome the generation shortfall). Idaho Power determined there are likely to be insufficient down-regulation resources available at certain times of the year. Specifically, down-regulation deficiencies occur during periods of oversupply when all of the Idaho Power generation resources are reduced to safe operating levels, yet company generation plus the intermittent generation exceeds customer load.

Idaho Power analyzed the flexible resource needs using the data developed for the solar integration study. The data consisted of actual load, actual wind, and simulated PV solar generation for 500 MW of solar plant at six geographic locations throughout Idaho Power's service area. The data were developed at five-minute intervals over three water years from October 2010 through September 2013.

The first step in the analysis was to estimate the flexible resource requirement. Idaho Power calculated the flexible need requirement in 5-, 10-, 15-, 30-, 45-, and 60-minute intervals from the dataset, and the results are presented in Figure 9.4. The one-percent likelihood shown in Figure 9.4 is the total likelihood, composed of one-half percent up plus a one-half percent down.

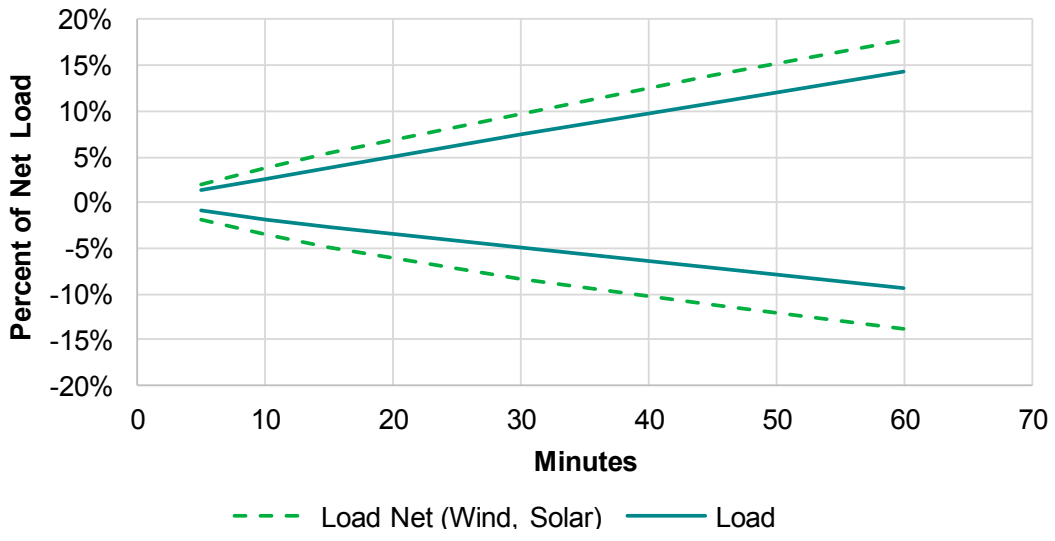


Figure 9.4 Flexibility need (500 MW solar, existing wind, 1% likelihood)

Figure 9.4 shows that adding intermittent resources to the Idaho Power system increases the flexibility need, both up and down. Idaho Power has a second solar integration study underway to further analyze the effects of adding intermittent utility-scale solar PV generation to Idaho Power's system.

Idaho Power used a resource dispatch simulation of Idaho Power's system to forecast available system flexibility after adding 500 MW of solar PV to the generation mix. The purpose of the simulation was to assess both the regulation requirement and supply. The simulation was performed using a one-hour time step. Up-regulation and down-regulation quantities were assessed to determine the net result of flexible resource needs and flexible resource supply. A representative graph of system regulation during the spring is shown in Figure 9.5 (April 2012 historical data with the addition of 500 MW of solar PV on the system).

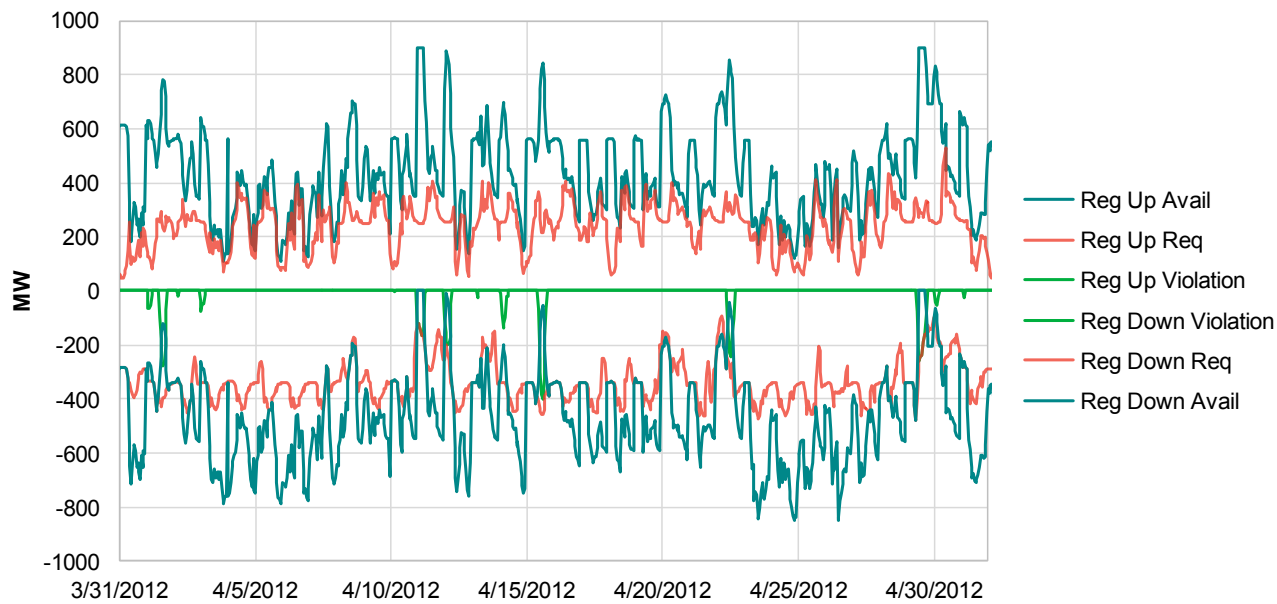


Figure 9.5 System regulation

Figure 9.5 shows the five quantities:

1. Up-regulation available
2. Up-regulation requirement
3. Regulation violation (both up and down)
4. Down-regulation requirement
5. Down-regulation available

Figure 9.6 is simplified to focus on the regulation violation by removing the lines showing the regulation requirement and the regulation available.

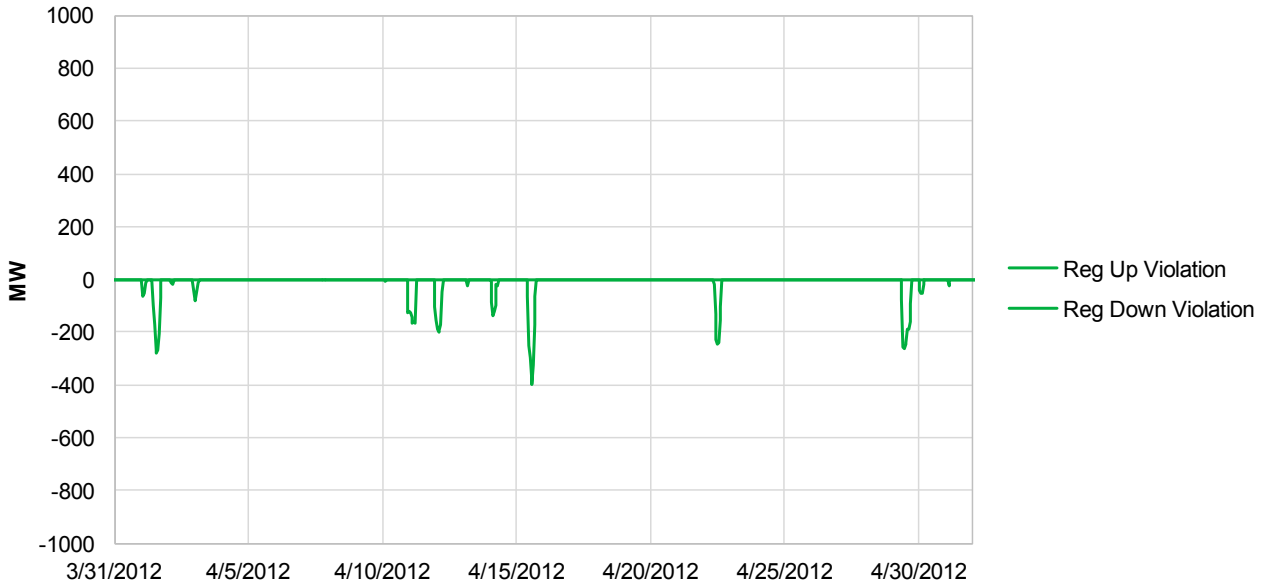


Figure 9.6 Regulation violations, spring 2012

Figure 9.6 shows significant down-regulation violations during certain hours of the spring. The down-regulation violations occur during periods of oversupply when all of the Idaho Power generation resources are reduced to safe operating levels, yet company generation plus the intermittent generation exceeds customer load. There are no up-regulation violations during the April study period.

Idaho Power analyzed the other three seasons of the year and determined that regulation is primarily an issue during the spring. The graphs for summer, fall, and winter are shown in figures 9.7 through 9.9.

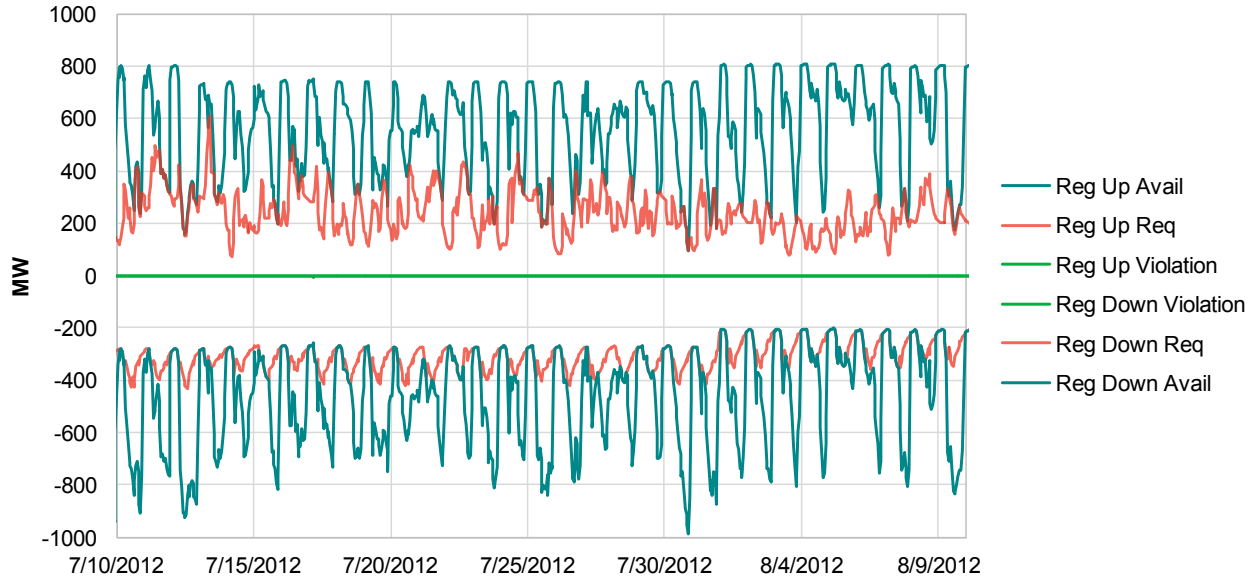


Figure 9.7 Regulation violations, summer 2012

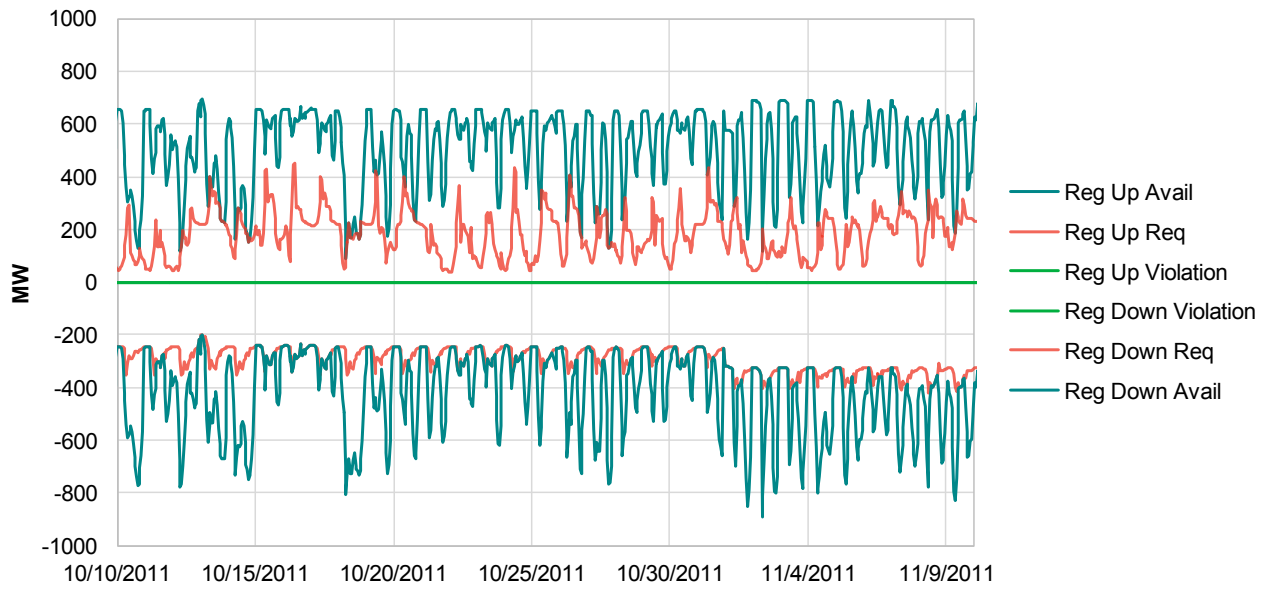


Figure 9.8 Regulation violations, fall 2011

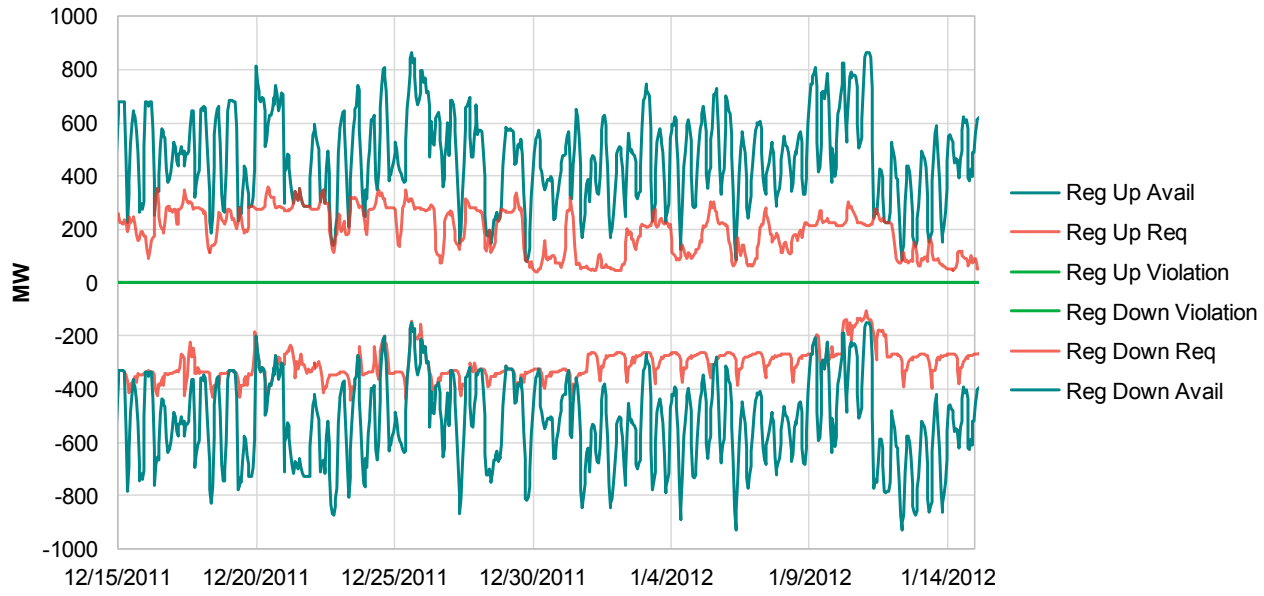


Figure 9.9 Regulation violations, winter 2011/2012

As shown in figures 9.7 through 9.9, zero violations are evident through the summer, fall, and winter seasons, except a single small down-regulation violation in one hour of the summer season. The summer down-regulation violation is less than 10 MW; however, down-regulation violations could become an issue during some summer hours. Several times during the four seasons, the regulation available equals the regulation requirement, indicating Idaho Power's system is operating at the regulation limits. The simulations show it is more likely for Idaho Power's system to face down-regulation limits than up-regulation limits.

Idaho Power is currently conducting a second solar integration study. Idaho Power anticipates additional regulation analysis will occur as part of the second solar integration study. Idaho Power expects to update the flexibility analysis with the results of the second solar integration study in the 2017 IRP. Down-regulation is a significant concern during periods of oversupply for Idaho Power and other utilities in the region. Idaho Power is currently investigating methods to address potential down-regulation violations.

Loss of Load Expectation

Idaho Power used a spreadsheet model[10] to calculate the LOLE for the 11 portfolios studied in the stochastic risk analysis in the 2015 IRP. The assessment assumes critical water conditions at the existing hydroelectric facilities and the planned additions for the selected portfolios. As mentioned in the Capacity Planning Margin section, Idaho Power uses a capacity benefit margin (CBM) of 330 MW in transmission planning to provide the necessary reserves for unit contingencies. The CBM is reserved in the transmission system and is sold on a non-firm basis until forced unit outages require the use of the transmission capacity. The 2015 IRP analysis assumes CBM transmission capacity is available to meet deficits due to forced outages.

The model uses the IRP forecasted hourly load profile, generator and purchase outage rates (equivalent demand forced outage rates), and generation and transmission capacities to compute a LOLE for each hour of the 20-year planning period. Demand response programs were modeled as a reduction in the hourly load for the 10 peak days in a given year, although existing programs allow use up to 15 days. The 10-day assumption was chosen as a conservative reflection of reality where it is assumed some days will be left in reserve for unexpected extreme weather. Ice TES resources were modeled as a reduction to hourly load during afternoon/evening hours in summer months and an increase in hourly load during night hours in summer months. The LOLE analysis is performed monthly to permit capacity de-rates for maintenance or a lack of fuel (water). Resource capacities are assumed to be constant for all hours each month with the exception of demand response and ice TES as explained above, as well as solar PV resources. PV resources are modeled with a capacity that varies by hour for each month according to changing daylight hours and sun position.

The typical metric used in the utility industry to assess probability-based resource reliability is a LOLE of 1 day in 10 years. Idaho Power chose to calculate a LOLE on an hourly basis to evaluate the reliability at a more granular level. The 1-day-in-10-years metric is roughly equivalent to 0.5 to 1 hours per year.

The results of the LOLE probability analysis are shown in Figure 9.10. Several portfolios result in a LOLE greater than 2 hours per year, which indicates that additional purchases or generation capacity would be necessary in the future to achieve acceptable performance. The results indicate that resource portfolios 2(a), 6(b), 8, 10, 11, and 13 are the best performers with an LOLE under two hours per year over the 20-year planning horizon. Additional data can be found in *Appendix C—Technical Appendix*.

[10] Based on Roy Billinton's *Power System Reliability Evaluation*, chapters 2 and 3. 1970.

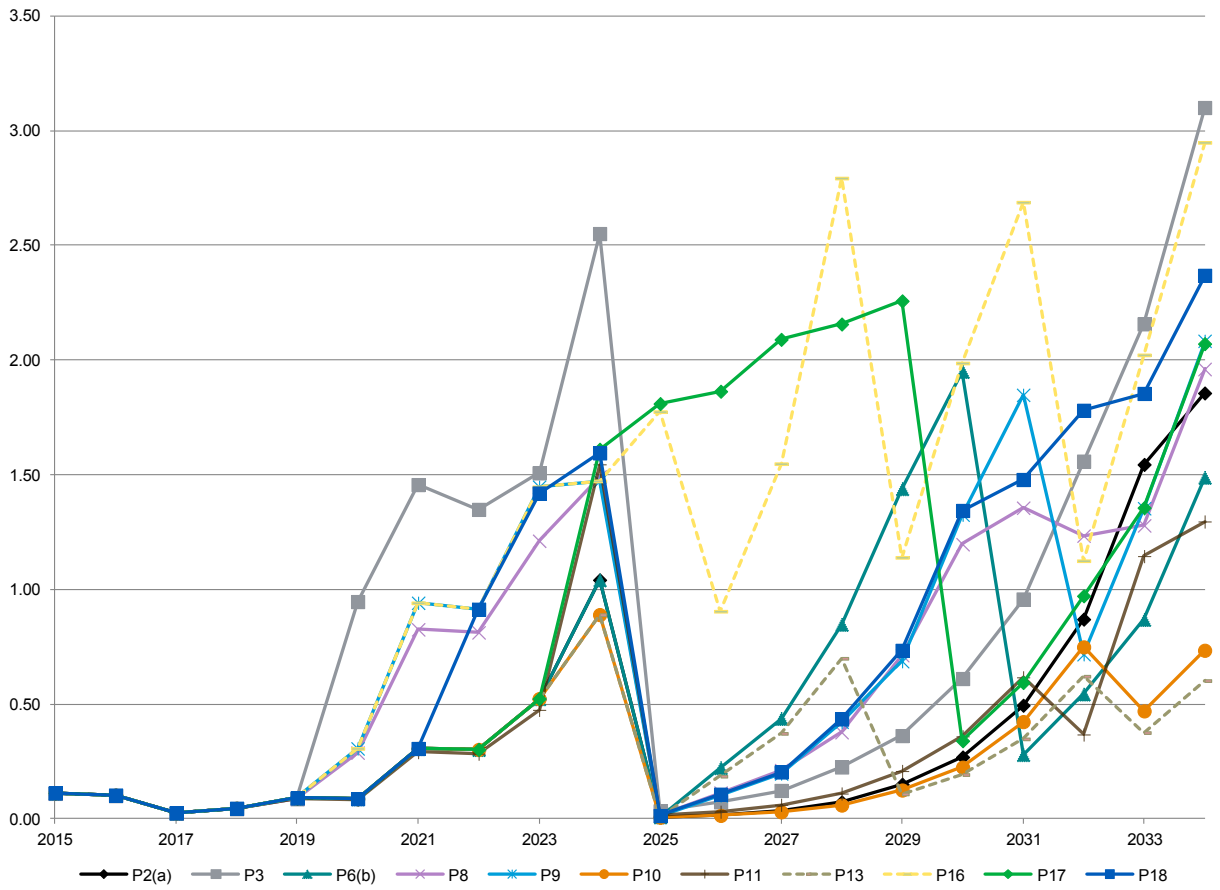


Figure 9.10 LOLE (hours per year)

10. Preferred Portfolio and Action Plan

Preferred Portfolio (2015–2034)

Analysis for the 2015 IRP consistently indicates favorable economics associated with two significant resource actions: the B2H transmission line and the early retirement of the North Valmy Power Plant. IRP analysis suggests a strong connection between these resource actions, both of which are characterized by uncertain timetables. Specifically, an acceleration in the completion of the B2H line can be expected to provide the system reliability and access to markets allowing for a corresponding acceleration in the early retirement of North Valmy.

The B2H transmission line and early North Valmy retirement are two key resource actions of portfolio P6(b), the 2015 IRP's preferred resource portfolio. Portfolio P6(b) contains both actions in the year 2025, with the completion of the transmission line preceding the end-of-year coal plant retirement. Portfolio P6(b) contains no other resource actions through the end of the 2020s, adding 60 MW of demand response and 20 MW of ice-based TES in 2030 and a 300-MW CCCT in 2031.

The absence of resource needs in portfolio P6(b) prior to the 2025 retirement of North Valmy is noteworthy. The resource sufficiency through the early 2020s shields portfolio P6(b) from risk exposure associated with the following factors:

1. Uncertainty related to planned but yet-to-be-built PURPA solar; further project cancellations beyond those already observed will have a greater impact on portfolios requiring capacity additions in the early 2020s.

2. Uncertainty related to the EPA's proposed regulation of CO_2 emissions from existing power plants under CAA Section 111(d), particularly the effect of the final regulation on operations at coal and natural gas-fired power plants in the proposed interim compliance period beginning in 2020.

3. Uncertainty related to the completion date of the B2H line due to permitting issues and needs of project partners.

4. Uncertainty related to retirement planning for a jointly owned power plant (North Valmy), specifically the challenges associated with arriving at a mutually feasible retirement date.

Uncertainty is a common part of long-term integrated resource planning. Even with the increased uncertainty surrounding the 2015 IRP, the analysis indicates completion of the B2H line and early retirement of the North Valmy Power Plant are prudent actions. The timing of the actions can be appropriately adjusted as conditions related to the four factors listed above become actionable.

Action Plan (2015–2018)

The action plan for the 2015 to 2018 period includes items specifically related to the preferred portfolio P6(b) and other items irrespective of the portfolio selected. The P6(b) action items

include continued permitting and planning for the B2H transmission line and investigation of North Valmy retirement in collaboration with plant co-owner NV Energy. The pursuit of these items over the action plan period is critical to the successful and timely implementation of the preferred portfolio.

The Gateway West transmission line remains a key future resource to Idaho Power and the region, promoting continued grid reliability in a time of expanding variable energy resources. Therefore, the plan includes continued permitting and planning associated with the Gateway West project.

CAA Section 111(d) will potentially have a pronounced impact on coal and natural gas-fired power plant operations on Idaho Power's system and throughout the nation. Idaho Power will remain involved as a stakeholder as CAA Section 111(d) moves toward finalization and implementation. As stipulations of the final regulation become clearer, and as implementation planning is developed, Idaho Power will assess the impacts of CAA Section 111(d) on the preferred portfolio.

The action plan also includes the following items:

- Continued pursuit of cost-effective energy efficiency, working with stakeholder groups, such as EEAG and regional groups such as NEEA
- Filing to amend the FERC license to adjust the 50-MW Shoshone Falls project expansion and efforts related to the study and construction a smaller upgrade of the project with a scheduled on-line date in the first quarter of 2019
- Completion of SCR retrofits for Jim Bridger units 3 and 4
- Begin economic evaluation of SCR retrofits for Jim Bridger units 1 and 2 (SCR installation required for Unit 1 in 2022 and for Unit 2 in 2021)

Table 10.1 provides actions with dates for the 2015 to 2018 period.

Table 10.1 Action plan (2015–2018)

Year	Resource	Action	Action Number
2015–2018	B2H	Ongoing permitting, planning studies, and regulatory filings	1
2015–2018	Gateway West	Ongoing permitting, planning studies, and regulatory filings	2
2015–2019	Energy efficiency	Continue the pursuit of cost-effective energy efficiency. The forecast reduction for 2015–2019 programs is 84 average megawatts (aMW) for energy demand and 126 MW for peak demand.	3
2015–2016	N/A	Coordinate with government agencies on implementation planning for CAA Section 111(d).	4
2015	Shoshone Falls	File to amend FERC license regarding 50-MW expansion	5
2015	Jim Bridger Unit 3	Complete installation of SCR emission-control technology	6
2015-2016	Shoshone Falls	Study options for smaller upgrade ranging in size up to approximately 4 MW	7
2016	Jim Bridger Unit 4	Complete installation of SCR emission-control technology	8

Table 10.1 Action Plan (2015–2018) (continued)

Year	Resource	Action	Action Number
2016	North Valmy units 1 and 2	Continue to work with NV Energy to synchronize depreciation dates and determine if a date can be established to cease coal-fired operations	9
2017	Shoshone Falls	Commence construction of a smaller upgrade	10
2017	Jim Bridger units 1 and 2	Evaluate the installation of SCR technology for units 1 and 2 at Jim Bridger in the 2017 IRP	11
2019	Shoshone Falls	On-line date for smaller upgrade during first quarter	12

Idaho Power has several choices when procuring long-term energy. It can develop and own generation assets, rely on PPA and market purchases, or use a combination of the two strategies. During the action plan period, Idaho Power expects to continue participating in the regional power market and enter into mid- and long-term PPAs. However, 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.

Conclusion

The 2015 IRP analysis indicates favorable results for the B2H transmission line and the early retirement of the North Valmy Power Plant. The analysis also suggests a linkage between the B2H line and the early retirement of North Valmy. Acceleration in the completion of the transmission line could bring about a corresponding acceleration in scheduling for North Valmy retirement.

View of the Hemingway Substation.

Idaho Power has treated the B2H transmission line as an uncommitted resource in every IRP beginning with the 2006 IRP. For every IRP, including the 2015 IRP, the B2H line has been a top-performing resource alternative. The consistency of these analyses indicates it is time for Idaho Power, the transmission line partners, and the various regulatory and governmental agencies to complete a final permitting and construction schedule for the B2H transmission line.

Idaho Power strongly supports public involvement in the planning process. Idaho Power thanks the IRPAC members and the public for their contributions to the 2015 IRP. The IRPAC discussed many technical aspects of the 2015 resource plan along with a significant number of political and societal topics at the meetings, portfolio design workshop, and field trip to an Idaho Power facility. Idaho Power's resource plan is better because of the contributions from the IRPAC members and the public.

Idaho Power prepares an IRP every two years, and the next plan will be filed in 2017. As described in this plan, the coming years are characterized by considerable uncertainty

associated with energy-related issues on the state, regional, and national levels. Idaho Power anticipates that as uncertainty related to these issues clears, the 2015 IRP preferred portfolio and action plan may be adjusted in the next IRP filed in 2017, or sooner if directed by the IPUC or OPUC.