Office of the Secretary
Service Date
December 30, 2011

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S 2011 INTEGRATED RESOURCE PLAN (IRP)	**CASE NO. IPC-E-11-11**
	ACCEPTANCE OF FILING
	ORDER NO. 32425

On June 30, 2011, Idaho Power Company filed an Application requesting the Commission issue an Order accepting the Company's 2011 Integrated Resource Plan (IRP). As directed in previous Commission Orders, the Company prepares and files a biennial IRP explaining in detail how the Company intends to serve anticipated electrical requirements of its customers. The 2011 IRP consists of four documents: (1) the 2011 Integrated Resource Plan; (2) sales and load forecast (Appendix A); (3) demand-side management 2010 annual report (Appendix B); and (4) technical appendix (Appendix C). The primary goals of Idaho Power's 2011 IRP are to: (1) identify sufficient resources to reliably serve the growing demand for energy within Idaho Power's service area during a 20-year planning period; (2) ensure the selected resource portfolio balances cost, risk, and environmental concerns; (3) give equal and balanced treatment to both supply-side resources and demand-side measures; and (4) involve the public in the planning process in a meaningful way. Idaho Power Application, p. 3. The Company prepares the IRP with assistance from the Integrated Resource Plan Advisory Council (IRPAC), comprised of members of the environmental community, major industrial customers, agricultural interests, Idaho state legislators, representatives of the Commission Staff, representatives from the Idaho Office of Energy Resources, and the Northwest Power and Conservation Council. Idaho Power Application, p. 2.

The IRP evaluates energy needs during two successive 10-year planning periods (2011-2020 and 2021-2030). Idaho Power expects its number of customers to increase from around 492,000 in 2010 to more than 650,000 by the end of 2030, and expects its average load to increase by 29 average MW (1.4%) annually. Summertime peak hour loads are expected to increase by 69 MW (1.8%) annually through 2030.

The Application states that the Company responded to specific instructions the Commission provided when it approved the Company's 2009 IRP in Order No. 32042.

Specifically, the Commission recommended the Company: (1) compare the risks, costs, and environmental benefits of strategies that directly reduce emissions from its resource mix to the purchase of emission offsets or offset options; (2) include in the 2011 IRP "a more detailed discussion on how it plans to reach its carbon reduction goals and curtail its coal operations," and recommending that the Company include the quantity of greenhouse gas emissions per average MWh associated with each portfolio; (3) "redouble its efforts to realize the achievable potential for savings from efficiency and DSM programs documented in the Nexant report," and recommending that the Company identify economic and non-economic barriers to deployment of energy efficiency and DSM initiatives; and (4) because the Company has increased reliance on natural gas in its resource portfolio, the Company address in the 2011 IRP "the risks to the Company and its customers associated with the reliance on such an economically volatile commodity." Idaho Power Application, p. 5. The Company states that it specifically addressed each of these directives in the 2011 IRP.

On September 14, 2011, the Commission issued a Notice of Filing and Notice of Modified Procedure providing for a 60-day written comment period, followed by a 14-day reply comment period. Comments were filed by the Power County and Cassia County Commissioners, the Idaho Conservation League, the Renewable Northwest Project, the Snake River Alliance, the Commission Staff, and a few members of the public. Idaho Power filed reply comments.

The IRP Methodology

Idaho Power duplicated the approach it used to develop the 2009 IRP by dividing the 20-year planning horizon into two 10-year periods. According to the Company, splitting the planning horizon into two 10-year periods "prevents near-term resource decisions from being influenced by the availability of resources that are dependent on technological advancements in the second 10 years." 2011 IRP, p. 3.

Idaho Power developed peak-demand and average load forecasts across the IRP's 20-year planning horizon accounting for new customer growth in each customer class, changes in customer class usage characteristics, changes in the service area economy, existing energy efficiency program performance, loss factors, fuel prices, weather variability, and the potential for a new electric vehicle market. These forecasts were netted against Idaho Power's current and committed resource base to determine average energy and peak-hour load and resource balance deficits. Current resources include all existing DSM programs, current levels of PURPA development, existing PPAs, firm Pacific Northwest import capability, and generation from all existing and committed Idaho Power resources. Committed resources include Langley Gulch (CCCT) and the Shoshone Falls upgrade (hydro) available in years 2012 and 2015, respectively.

Once load and resource balance deficits were identified, Idaho Power designed nine resource portfolios to address deficits project to occur during the near-term time period (2011-2020). These were developed considering the technology readiness of different types of load-serving resources, the capital and operational cost of various resources, the future cost of natural gas, the cost of carbon and other emissions, production tax and renewable energy credits (RECs), future national renewable energy legislation, and the cost of incremental transmission investment. Each near-term portfolio was analyzed using cost and risk as criteria. Variable costs were determined using AURORA modeling capability, and internal financial analysis modeling tools used to evaluate capital cost. Risk was evaluated based on sensitivity to various levels of REC prices, carbon costs, natural gas prices, generation capital cost, DSM adoption variability, and load variability. Using this analysis, the Company selected preferred and alternate near-term portfolios.

In the second step, the Company assumed the preferred near-term portfolio would be fully implemented by the year 2021 with load and resource balance deficits adjusted to reflect the additional resources. To address deficits that occur in years 2021 through 2030, the Company designed ten additional resource portfolios. Employing the same type of analysis used to select the near-term portfolios, Idaho Power chose preferred and alternate long-term portfolios, again using cost and risk as criteria.

Load and Resource Balance

Average Energy Load Forecast

The current recession has contributed to a reduction in overall electricity consumption within Idaho Power's service area, declining 3.5% in 2009 and 1.2% in 2010. Industrial and commercial electricity consumption has decreased, while new residential customer growth has increased, but at a much slower rate since the start of the recession. As a result of continued pessimism in the economy, the Company's 2011 IRP average load forecasts are lower than forecasts in the 2009 IRP through year 2015. The Company assumed that by 2012, the recession will subside and the economy will recover, and it anticipates that by 2015 new customer growth rates will be equivalent to growth that occurred between the year 2000 and 2004. For the rest of the forecast horizon, average load is higher in all remaining years compared to the 2009 IRP. This results in an overall average system growth rate of 1.4 percent per year across the 20-year planning horizon.

For the first time, the Company incorporated the effect of plug-in hybrid electric vehicles on load growth. Moody's Analytics, EPRI and Oak Ridge Laboratory market adoption and end-use consumption assumptions were used to develop the forecast. The Company acknowledged there is significant uncertainty in the forecast due to a lack of empirically derived data, but because of its relatively small impact, from 9 aMW in 2020 to 43 aMW in 2030, its effect on the total load forecast is minimal.

Because of the interest potential large customers have recently shown in locating into Idaho Power's service territory, a "Special" contract customer was incorporated into the load forecast in the 2011 IRP. The "Special" customer was reflected in the Company's firm load forecast starting in 2011 at 2 aMW and ramping up to 54 aMW in 2016. This is in addition to the four large contract customers already included (Micron Technology, Simplot Fertilizer, INL, and Hoku Materials). The potential for a large new load addition as a separate planning scenario is helpful to understand the overall cost impact of a new industrial customer so that it can be compared effectively with benefits related to economic development.

Also included in the 2011 IRP load forecast is the impact of current DSM energy efficiency programs. The programs are reflected in the forecast based on the savings the Company is predicting to achieve considering changes in program design, trends in participation, future changes in codes and standards, and where the program is in its life cycle. Idaho Power assumed that current program performance remains constant after 2015 and is ramped down starting in year 2020 until the end of the IRP planning horizon. New programs were added as a resource equivalent to a current or committed resource. The amount of savings per customer and per unit of load steadily increases, but levels off and begins to decrease during the last five years of the 20-year planning horizon. Idaho Power Company (2011 IRP: Appendix C – Technical Appendix, Table DSM-5, DSM-10; Appendix A – Sales and Load Forecast, Appendix A1). According to the Company, the focus was on program performance and its effect on average energy use during the first five years of the IRP planning horizon. 2011 IRP, p. 38.

The last major effect included in the average load forecast is weather. In addition to a median expected case weather scenario (50th percentile), Idaho Power prepared two alternative scenarios, a 70th percentile and a 90th percentile case. The Company used the 70th percentile weather scenario as a basis to forecast its monthly average load for all of its IRP planning. According to the Company, this provides a 10% monthly planning margin for the preferred resource portfolio when compared to demand using the expected case.

Peak Demand Load Forecast

Idaho Power forecasts system peak-hour loads by summing the coincident peak-demand periods across all customer classes and uses the 70th percentile average monthly load forecast as a basis for the peak-hour load forecast. Winter peak demand is mostly driven by cold weather space heating, while summer peaks are caused by hot weather air-conditioning and agricultural irrigation needs. Summer peak-hour loads are consistently larger than winter peak-hour loads making Idaho Power a summer peaking utility. For example, the largest system peak-hour load event recorded by the utility was 3,214 MW occurring on June 30, 2008 at 3 p.m. while the largest winter peak was 2,528 MW occurring on December 10, 2009 at 8:00 a.m.

Other major factors include average peak-day temperature and precipitation assumptions due to the number of customers and intensity of energy use by customer classes with significant air-conditioning and irrigation needs. In most cases, these types of loads increase considerably with hotter temperatures which also happen coincidently with the growing season, while a lack of precipitation can increase irrigation electricity use.

The Company uses a conservative 95th percentile average peak-day temperature and 90th percentile precipitation assumptions to forecast peak-hour load, resulting in an IRP peak-hour load forecast that is projected to grow to 4,901 MW in year 2030 from the highest recorded peak of 3,214 MW in June 2008.

Current and Committed Resources

The 2011 IRP nets the peak-hour and average energy load forecasts against current and committed resources to determine deficits that future resource portfolios will need to address. These resources total 4,926 MW of total nameplate capacity and include all existing and committed Idaho Power owned resources, current levels of PURPA contracts, existing power purchase agreements, firm Pacific Northwest import capability, as well as all demand response DSM programs.

The 2011 IRP included the 49 MW Shoshone Falls upgrade in 2015 along with 300 MW of capacity from Langley Gulch in 2012 as committed resources. There is also a reduction in coal-fired capacity reflected in the 2011 IRP due to the projected shutdown of the Boardman Plant in 2020. Portland General Electric, the majority owner and operator, has agreed to close the plant as a result of legal proceedings in Oregon.

According to the Company, demand response is included as a resource to help meet peak-hour loads on par with supply-side resources. Beyond year 2015, demand response is assumed to be flat, held at 351 MW throughout the rest of the 20-year planning horizon. Given that peak-hour load and the number of customers are projected to grow, this effectively means the Company is projecting demand response to shrink on a per customer and per unit of demand basis. However, if electricity prices and avoided costs are projected to increase, it is expected that cost-effectiveness thresholds would become easier to meet and demand response would grow.

In the 2011 IRP, the Company changed the strategic role demand response plays in resource acquisition by modifying the criteria used in the 2009 IRP to value demand response. The value of demand response and how it compares to avoided supply side resources was a significant issue in Case No. IPC-E-10-46.

Load Resource Balance Deficits

Based on the Company's load resource balance analysis, average monthly deficits begin occurring in July 2017 using 70th percentile water conditions and 70th percentile average load scenarios. The size of the deficit is 12 aMW increasing to 1,232 aMW by the end of the 20-year planning horizon. Similarly, using 95th percentile peak-hour load conditions and 90th percentile water conditions, deficits begin occurring as early as July 2011 growing to a maximum of 1,232 MW in June 2030.

The Company's resource portfolios were designed to eliminate peak-hour deficits. When these resources were modeled, average load balance deficits were also eliminated.

Resource Portfolios

The Company developed nine near-term resource portfolios for the first 10-year period and ten long-term portfolios for the second 10-year period. All portfolios were designed to meet resource deficits as well as a federal renewable energy standard as minimum requirements. Senate Bill S.3813 by Senator Jeff Bingaman was used as the standard which has a three percent renewable requirement by the year 2012 and 15 percent by 2021. The nine near-term resource portfolios considered by the Company are shown below.

Near-Term Resource Portfolios (2011-2020)

Year	1-1 Sun & Steam	1-2 Solar	1-3 B2H	1-4 SCCT	1-5 CCT
2011					
2012	Solar PV-1				
2013	Solar PV-5				
2014	CHP-75	Solar PV-5			
2015	Solar PV-30	Solar PT-100	Eastside Purchase	SCCT Frame	CCCT
2016	CHP-100	Solar PT100	B2H-450		
2017	Geothermal-52	Solar PT-125		SCCT Frame	
2018	Solar PT-125	Solar PV-50			
2019	Solar PV-30	Solar PT-100		SCCT S Aero-94	SCCT Frame
2020	Solar PT-75	Solar PV-50			
MW	**493**	**530**	**450**	**434**	**470**

Year	1-6 CHP	1-7 Balanced	1-8 Pumped Storage	1-9 Distributed Gen.
2011				
2012				Dist Gen-10
2013				
2014				
2015	CHP-100	CHP-100	Pump St-80	SCCT Frame
2016	SCCT Frame	SCCT Frame	SCCT Frame	
2017		SolarPV-10		SCCT Frame
2018	CHP-50	Solar PT-100	Pump St-80	
2019	CHP-50	Geothermal-26	SCCT S Aero-47	SCCT S Aero-94
2020	SCCT S Aero-94	SCCT S Aero-47	Pump ST-80	
MW	**464**	**453**	**457**	**444**

When designing different portfolios, the Company analyzed transmission capacity constraints based on assumptions about the location of different generation resources and off-system purchases. The cost of transmission investment was included in the net present value and incremental revenue requirements; however, assumptions for including transmission investment were different between the first and last 10-year planning periods. In the first 10-year planning period, incremental in-service-area transmission capacity was only included if additional capacity was needed to deliver power from a new resource to the Treasure Valley. The only incremental interstate transmission line was the addition of Boardman to Hemingway in portfolio 1-3 B2H.

Portfolios analyzed for the second ten years of the planning period are shown in the table below.

Long-Term Resource Portfolios (2021-2030)

Year	2-1 Nuclear	2-2 IGCC	2-3 SCCT/Wind	2-4 CCT/Wind	2-5 Hydro/CHP
2021	Solar PT-100	Geothermal-52	SCCT S Aero-141	CCCT	Hydro Sm-60
2022	Pump St-50	SCCT Frame	Wind-100	Wind-150	CHP-75
2023	Solar PT-100		SCCT S Aero-141		Pump St-80
2024	Nuclear	CHP-50	Wind-100		CHP-100
2025		Solar PT-75	SCCT S Aero-94		Hydro-40
2026		IGCC w/ CS	Wind-100	CCCT	Pump St-80
2027			SCCT S Aero-141		Hydro Sm-100
2028	Nuclear	Solar PT-75	SCCT S Aero-141	Wind-150	SCCT S Aero-141
2029	Pump St-50		SCCT S Aero-94	SCCT Frame	Hydro Sm-80
2030					Hydro Sm-60
MW	**800**	**802**	**1052**	**1070**	**816**

Year	2-6 Balanced 1	2-7 Balanced 2	2-8 PNW Transmission	2-9 E/S Transmission	2-10 Renewable
2021	Geothermal-52	Geothermal-52	Geothermal-52	Geothermal-52	CHP-75
2022	SCCT Frame	CHP-75	PNW Purchase	E/S Purchase	Pump St-80
2023		SCCT Frame			Solar PT-150
2024	Solar PT-50				
2025	CCCT	Geothermal-52			CHP-75
2026		CHP-75			Solar PT-150
2027		Hydro Sm-60	Solar PV-20	Solar PV-20	Solar PV-150
2028	Hydro Sm-60	CCCT	Geothermal-52	Geothermal-52	Geothermal-52
2029	SCCT Frame		SCCT Frame	SCCT Frame	Hydro Sm-100
2030					Solar PV-200
MW	**802**	**784**	**794**	**794**	**1032**

During this period, Boardman to Hemingway was assumed to be built because it was selected as the preferred portfolio in the near-term and its cost was included in all long-term portfolios. However, *all* additional transmission investment needed to enable market purchases and required to take new generation to load were included, not just transmission investment into the Treasure Valley. This includes the cost of interstate transmission lines needed for market purchases from the Pacific Northwest in portfolio 2-8 PNW Transmission and from the East by including the cost of Gateway West in portfolio 2-9 E/S Transmission (both with 2022 completion dates). The cost of Gateway West was also included in all long-term resource portfolios that required it to deliver any amount of new generation to load. Idaho Power acknowledged that there is significant uncertainty in the location of new generation sources, and believes it is prudent to continually evaluate new transmission lines (2011 IRP, p. 6) so the Company can make decisions in the best interests of the public with sufficient lead time that allows for timely construction.

Preferred and Alternate Portfolios

Based on its analysis, Idaho Power selected 1-3 Boardman to Hemingway (B2H) as the *preferred* near-term portfolio because it had the lowest total cost and showed the third lowest sensitivity to risk factors. The preferred portfolio is characterized by completion of the Boardman to Hemingway transmission line in year 2016 which will allow the Company to purchase up to 450 MW of power from the Pacific Northwest. Idaho Power also selected 1-4 SSCT as an *alternative* portfolio in case the Boardman to Hemingway transmission line is delayed or cancelled. It was selected because it had the second lowest total cost and the second lowest sensitivity to risk. The portfolio is characterized by the addition of three simple-cycle gas-fired combustion turbines in 2015, 2017, and 2019. Both short-term portfolio action plans are shown below.

Short-term Portfolio Action Plans (2011-2020)

	Preferred Resource Portfolio 1-3 Boardman to Hemingway	**Alternative Resource Portfolio 1-4 Simple Cycle Combustion Turbine**
2011		
2012		
2013	Solar Demonstration Project (500kW-1MW)	Solar Demonstration Project (500kW-1MW)
2014		
2015	Eastside PPA (83MW)	SCCT (170 MW)
2016	Boardman to Hemingway (450MW)	
2017		SCCT (170 MW)
2018		
2019		SCCT (94 MW)
2020		

The Company selected 2-6 Balanced 1 and 2-8 PNW Transmission as the preferred and alternate long-term portfolios, respectively (see table below). The Balanced 1 portfolio is characterized by a diverse mix of different types of renewable and natural gas generation resources. The PNW Transmission portfolio consists mainly of incremental market purchases from the Pacific Northwest requiring construction of additional transmission capacity in the Idaho-Northwest and Brownlee East transmission paths. Although the preferred long-term portfolio did not have the lowest total cost (3^{rd} lowest) or sensitivity to risk (4^{th} lowest), the Company justified its selection because the two portfolios that performed better against quantitative measures relied heavily on market purchases of power as well as construction of new transmission lines, both of which carry substantial risk. The Company did select the best performing of the two highest scoring portfolios, 2-8 PNW Transmission, as the alternate portfolio, but with caveats to reassess in the future.

Long-term Portfolio Action Plans (2021-2030)

	Preferred Resource Portfolio 2-6 Balanced 1	Alternative Resource Portfolio 2-7 Pacific Northwest Transmission
2021	Geothermal (52 MW)	Geothermal (52 MW)
2022	SCCT (170 MW)	Pacific Northwest Purchase (500 MW)
2023		
2024	Solar Power Tower (50 MW)	Solar Power Tower (50 MW)
2025	CCCT (300 MW)	CCCT (300 MW)
2026		
2027		Solar PV (20 MW)
2028	Small Hydro (60 MW)	Geothermal (52 MW)
2029	SCCT (170 MW)	SCCT (170 MW)
2030		

Solar Demonstration Project

Idaho Power included a solar demonstration project in its 2011 IRP to be implemented sometime in 2012 with an estimated cost between $2 and $4 million. The proposal is for a 0.5 to 1 MW solar photovoltaic (PV) resource. The Company believes that the facility would "provide useful data and give the company experience owning and operating this type of resource . . . and better evaluate the advantages and disadvantages of utility-scale solar PV projects and distributed rooftop programs." 2011 IRP, p. 11.

WRITTEN COMMENTS

The written comments filed by the County Commissioners of Power County and Cassia County address a single issue in the IRP, specifically, the Gateway West transmission line project. The County Commissioners acknowledge that the 2011 IRP addresses the Gateway West project only as a long-term plan to be considered in 2021 to 2030, specifically noting that the near term 10-year action plan, 2011-2020, does not consider the Gateway West project. Nonetheless, the Commissioners are concerned that Idaho Power's own documents "indicate that the analysis that became the underlying basis for Gateway West has been greatly modified and revised." Accordingly, "the Counties believe these changes significantly question the purpose and need for this project." County Commissioners Comments, p. 2. The Commissioners believe Gateway West "is a much more remote possibility than what was asserted by Idaho Power in its purpose and need [for the project] to the BLM." Noting the total cost for the project may be in excess of $2 billion, and given the "uncertainty of many of the assumptions that lead to this proposal," the Commissioners state that caution should be exercised before proceeding with the project. The Commissioners ask the Commission to review and re-analyze Idaho Power's participation in the Gateway West project.

The Idaho Conservation League (ICL) addressed energy efficiency, carbon issues, solar power, and Hells Canyon relicensing in Idaho Power's IRP. Regarding energy efficiency programs, ICL notes that although these programs are the least cost resource, there is some risk associated with them. The Commission addressed this concern in response to the Company's 2009 IRP, stating an identification of barriers would be helpful in explaining and understanding the Company's efforts and strategy to close the gap between economic potential and achievable potential in its DSM programs. ICL Comments, p. 3. ICL believes Idaho Power did not adequately address the barriers issue, stating that "merely mentioning barriers and future evaluations is an insufficient process for explaining Idaho Power's efforts and strategy to acquire all cost-effective energy efficiency." ICL Comments, p. 3.

Regarding carbon issues, ICL notes that the IRP identifies plant modifications for emission controls at Jim Bridger for 2015, 2016, 2021, and 2022, but that the IRP "does not provide any further details on the costs or risks of this strategy." ICL Comments, p. 4. ICL accordingly encourages the Commission "to require Idaho Power to develop an integrated plan using both demand-side and supply-side resources to avoid these costly expenses and mitigate carbon emission risks in future IRPs." *Id.*

The solar power project identified in the IRP is a solar demonstration project devoted to testing new photovoltaic panels, inverters, and other mounting and tracking systems. ICL believes a more valuable use of Idaho Power's resources is to address issues like interconnection standards, net metering policies, and integrating distributed systems into the Company's larger system. Accordingly, ICL believes a demonstration project focused on rooftop solar is a better use of Idaho Power resources.

Regarding Hells Canyon relicensing, ICL notes that the IRP reports that the Company has recorded $153 million in relicensing costs of Hells Canyon Complex through March 2011, and that it is not possible to estimate the final total cost. ICL encourages the Commission "to require a more robust discussion of the Company's efforts and strategy to resolve the relicensing process in a timely manner." ICL Comments, p. 6.

Written comments filed by the Renewable Northwest Project (RNP) primarily address the Boardman to Hemingway transmission line. RNP generally supports the Company's development of the Boardman to Hemingway line and recognizes the benefits it will provide. Specifically, the transmission line will help the Company improve access to markets, meet summertime peak capacity needs with market purchases, and bring strong reliability benefits to Idaho Power's system. Recognizing that the Boardman to Hemingway transmission line could be delayed, RNP encourages Idaho Power to consider alternatives to its alternate resource portfolio, which is comprised solely of simple-cycle combustion turbine plants. RNP suggests the Company give demand-side management alternatives and solar photovoltaic resources consideration because pursuing those alternatives to lower peak needs could provide greater long term benefits to the utility and its customers. RNP Comments, p. 2.

RNP also made recommendations regarding Idaho Power's carbon emissions, and recommended "that the Commission require Idaho Power to analyze the costs and risks of maintaining its coal plants and how carbon costs and environmental regulations could alter their cost-competitiveness in the future." RNP Comments, p. 6. Regarding the Company's solar photovoltaic demonstration project, RNP recommended the Company consider geographic dispersion of several solar projects and not limit its evaluation only to the performance of the single project. Moreover, characterizing solar PV as already a mature technology with known characteristics, RNP questions "why a demonstration project is necessary before Idaho Power moves forward with a resource that can diversify its portfolio and help reduce its peak needs." Finally, RNP encouraged Idaho Power to look for ways that diverse and flexible balancing of resources can lower its cost of integrating wind energy.

Snake River Alliance (SRA) recommended the Commission accept Idaho Power's 2011 IRP, but stated several reservations. Specifically, SRA does not support the Company's alternate portfolio (Portfolio 1-4 SCCT) that the Company proposes in the event the Boardman to Hemingway transmission line does not materialize. SRA regards the alternate portfolio 1-4 to be "long in natural gas-fired simple cycle combustion turbines (434 MW) to meet capacity deficits in the event B2H is not built or is significantly delayed." SRA Comments, p. 3. As it has in the past, SRA expressed concerns that large scale additional investments in gas-fired generation present potentially significant costs and environmental risks to the Company, its customers, and its shareholders.

SRA also believes that Idaho Power in its IRP has not sufficiently addressed the future of its coal-fired generation fleet and specifically the environmental and economic risks associated with the continued dependence on coal-fired generation. SRA recommends the Commission direct Idaho Power to perform a more extensive analysis of its coal resources as a requirement for acceptance of its 2013 IRP. Noting that modifications to coal-fired power plants are expensive, SRA believes that "a utility IRP should explore in detail the least cost and least risk resource alternatives, be they retrofitted coal plants or renewable energy resources or DSM investments." SRA Comments, p. 5.

Regarding serving new large loads, the SRA stated concerns regarding adding an additional 80 MW of capacity from a gas-fired plant at a cost of $60 million. SRA suggested the Commission, if it is interested in exploring the addition of new generation to meet an unknown new demand, open a docket and convene a workshop to provide for stakeholder participation and review. Absent a more rigorous analysis of the need for an additional 80 MW of peak hour load, SRA expressed doubt that such an expenditure could be considered prudent.

Commission Staff also recommended that the Commission accept Idaho Power's 2011 IRP, but made specific recommendations to improve the IRP. Specifically, Staff recommended the Company improve (1) modeling scenarios where the impacts of additional large new customers can be quantified, (2) the Company's methodology to more adequately consider and evaluate new DSM resources on par with supply-side resources, (3) portfolio design to address inadequate evaluation for the potential early retirement of existing coal plants in lieu of investing in costly emission controls, (4) quantifying transmission siting and market price risk in the analysis, and (5) providing sufficient rationale for a solar demonstration project. Staff Comments, p. 2. Staff stated it believes Idaho Power has demonstrated a rigorous approach in developing its IRP and has reasonably met the goals set by the Commission and requirements set forth for the filing of an IRP.

COMMISSION FINDINGS

The Commission has reviewed and considered Idaho Power's 2011 Integrated Resource Plan, including the related appendices, filed in Case No. IPC-E-11-11. We have considered as well the written comments and recommendations filed by the Power County and Cassia County Commissioners, the Idaho Conservation League, the Renewable Northwest Project, the Snake River Alliance, the Commission Staff, and the members of the public. The

Commission finds the Company's IRP contains the necessary information and is in the appropriate format as directed by Order No. 22299.

The written comments mainly compliment the process of developing and the product that is Idaho Power's 2011 IRP. Some of the parties participate in the IRP Advisory Council (IRPAC), and are complimentary of that process. For example, Snake River Alliance believes that "Idaho Power has, over the years, developed a meaningful and productive IRP process and that the Company and its IRPAC have worked diligently and productively in producing the 2011 IRP that is before the Commission for review and possible acceptance." SRA Comments, p. 1.

The Commission appreciates the involvement and written comments of the interested parties in this case. As some of the comments acknowledge, Idaho Power continues to improve the IRP preparation process, and encourages participation and suggestions from industry groups and customers. All of the commenters recommend that the Commission accept the 2011 IRP, but suggested the Commission address discrete issues. Many of the particular topics for discussion were also part of the 2009 docket, and the Commission in its Order approving the 2009 IRP directed the Company to respond to them in its 2011 IRP. For example, regarding the cost and environmental benefits of strategies to reduce emissions from the Company's resource mix, the Commission stated an expectation that Idaho Power monitor national developments and account for their impact on its resource planning. Order No. 32042, p. 19. The Commission likewise expected the Company to explain and plan for a future without the Boardman coal plant. *Id.* Idaho Power was also directed to address the risks to the Company and its customers associated with reliance on natural gas as a generation resource. Order No. 32042, p. 20.

The Commission finds that Idaho Power did address the issues as directed by the Commission in Order No. 32042. As the discussion in the comments demonstrates, however, many of the issues are not resolved and will need continued review in the Company's next IRP as more information becomes available. As Idaho Power prepares its 2013 IRP, including by listening to the interested parties that participate in the process, the Commission expects the Company to continue to respond to our previous directives and suggestions raised in this case. For example, we look forward to analysis of the Company's involvement in the Gateway West transmission line, the progress of the Company's solar demonstration project, the relicensing efforts for the Hells Canyon hydro projects, the evaluation of the potential for early retirement of existing coal plants, and quantifying transmission siting and market price risks.

ACCEPTANCE OF FILING

Based on our review, we find it reasonable to accept for filing and to acknowledge Idaho Power's 2011 Electric Integrated Resource Plan. Our acceptance of the 2011 IRP should not be interpreted as an endorsement of any particular element of the Plan, nor does it constitute approval of any resource acquisition contained in the Plan.

ORDER

IT IS HEREBY ORDERED that Idaho Power Company's 2011 Integrated Resource Plan (IRP) is accepted for filing.

DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho this 30th day of December 2011.

Paul Kjellander

PAUL KJELLANDER, PRESIDENT

Mack A. Redford

MACK A. REDFORD, COMMISSIONER

Marsha H. Smith

MARSHA H. SMITH, COMMISSIONER

ATTEST:

Jean D. Jewell

Jean D. Jewell
Commission Secretary

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