2009 IRP Advisory Council Meeting Minutes

Date: Thursday, March 19, 2009
Location: Idaho Power CHQ Auditorium

Introductions/Meeting Overview - Mark Stokes

Mark Stokes welcomed the participants to the meeting, noting that attendance was rather light and many of the participants had conflicting schedules. He then reviewed the agenda, noting the addition of a new presentation on committed resources to date.

Committed Resources - Mark Stokes

Mr. Stokes explained that the 2006 Integrated Resource Plan (IRP) had an additional 250 MW from coal coming on-line in 2019. However, because of all the changes with carbon and coal, this resource has been changed to gas. Mr. Stokes stated that participants may have recently heard news reports about Idaho Power's proposed new baseload resource, Langley Gulch. Additionally, Mr. Stokes noted that both the Langley Gulch project as well as the Boardman to Hemingway line (referred to as Boise to McNary in the 2006 IRP) was accounted for in the load and resource balance.

Due to the 2009 IRP filing deadline of June 2009, and an updated load forecast availability of late summer 2009, the load forecast information for the 2009 IRP will be based on the latest available forecast data from September 2008. Specifically, Mr. Stokes noted that the addition of Hoku will be accounted for in the 2009 IRP. However, Micron layoffs as well as recent requests for over 700 aMW from new large customers not yet not under contract will not be factored into the 2009 IRP.

Mr. Velikoff inquired about the upcoming public meetings. Mr. Stokes responded that the meetings on March 26th in Ontario, Oregon, and March 27th in Baker City, Oregon, are part of the Oregon public process related to Idaho Power's filing of the IRP Addendum on the Boardman to Hemingway line.

Mr. Stokes reported on the 2009 load forecast in comparison to the 2006 IRP. Mr. Stokes noted that there had very little change since the 2006 IRP. He highlighted the level growth through the 20-year reporting period and stated that the numbers shown were normalized numbers. He then reviewed the near-term forecast comparing the 2009 IRP load forecast, the updated December 2008 forecast, and weather-adjusted actuals through February 2009. Mr. Stokes hypothesized that because of the current economy, Idaho could possibly experience more growth due to outmigration from California.
Mr. Stokes noted that the forecast tracks closely to the actuals to date, and Idaho Power is watching to see how the load forecast tracks with actuals on a monthly basis.

John Gardner asked if the numbers were weather adjusted. Tom Noll responded that 70th percentile weather is used to develop the forecast and Mr. Stokes added that the actuals are already adjusted for weather.

Ken Miller asked if Idaho Power anticipates the actuals to continue to decline and then resume tracking the projections in the future. Mr. Stokes replied that the economic downturn is expected to continue. Brad Snow added that the actuals appear to be returning to the forecast trend line, but will decline at a sharper rate. Mr. Snow pointed out that the increase in the load forecast is due to Hoku, and stated if Langley Gulch and Boardman to Hemingway were removed, the deficits would be significant. He noted that these resources won't be on line until 2012, and the forecast is already indicating deficits.

Kevin Kitz asked how Idaho Power plans to meet these deficits. Mr. Stokes replied that the deficits would be met through market purchase opportunities, and while it is not the preference, Idaho Power is pursuing these avenues. In referring back to the graph, Mr. Stokes pointed out the addition of Langley Gulch in 2012, and the Boardman to Hemingway line in 2014. He stated the addition of these two resources will significantly reduce deficits to the point where July and August will be the only months with deficits.

John Velikoff inquired about the average capacity for Langley Gulch and Boardman to Hemingway. Mr. Stokes replied that Langley Gulch is a 330 MW project, and Idaho Power's share of the Boardman to Hemingway capacity is 225 megawatts.

Mr. Velikoff asked if there would be additional capacity available, and Mr. Stokes stated that Idaho Power is looking at these scenarios, and there could be the potential for additional capacity on the Boardman to Hemingway line.

Mr. Velikoff also inquired as to whether a combined heat and power facility (CHP) would be included in the 2009 IRP. Mr. Stokes replied that a 10 megawatt CHP will be included in the 2009 IRP. Mr. Velikoff asked whether any CHP projects were currently being negotiated. Mr. Stokes responded that Randy Allphin is currently talking to PURPA projects and is involved with pursuing those types of facilities.

In conclusion, Mr. Stokes stated that the current load forecast shows reduced load growth in the near-term, but not a reduction in load. Additionally the long lead times required to build large resources require the process of adding resources during the same time as the current economic recession.

Federal Renewable Portfolio Standard Draft Legislation – Rich Pagoaga

Rich Pagoaga from Idaho Power's Planning Department stated that at the February 3rd Integrated Resource Plan Advisory Council (IRPAC) meeting, he reported on legislation regarding a Federal Renewable Portfolio Standard (RPS) that identified a 15% RPS by 2020. However, two days following that February meeting, proposed legislation surfaced changing this requirement to 20% by 2021. Mr. Pagoaga stated that proponents of a federal RPS believe they currently have the necessary votes to pass legislation of this type, either as a stand-alone bill or as part of a larger energy bill. Currently there is one proposal and two bills before Congress. Mr. Pagoaga explained that in order to comply with a federal RPS, a utility must either build a renewable resource that qualifies for renewable

energy credits (RECs or green tags), purchase the RECs, or make an alternative payment to the federal government.

Mr. Pagoaga distributed a matrix comparison of the policy design elements of the three legislative proposals and reviewed the similarities and differences contained within each proposal.

Paul Kjellander questioned whether it was required for renewable generation facilities located on Indian lands to be on the reservation in order to qualify for double RECs. Because the answer to this question contained detailed qualifiers, Rich agreed to forward the specifics to Mr. Kjellander for further review.

Phil DeVol asked about the shelf life of RECs and questioned whether they could be used over a period of three years; and gave the example of good and poor water years. Mr. Stokes replied that a shelf life of three years would still be useable, therefore in the instance good and poor water years, RECs received from a good water year could still be applied to assist in meeting the RPS during a poor water year within that three-year timeframe.

Mr. Velikoff questioned the compliance requirements associated with a federal RPS. Mr. Stokes reported that utilities have the choice to 1) build their own resources, 2) buy RECs from others, or 3) make alternative payments. Mr. Velikoff asked whether the money received from the alternative payments is returned to all participants. Mr. Stokes stated that it is uncertain as to how this will be implemented. Mr. Stokes added that the Western Renewable Energy Generation Information System (WREGIS) is a renewable energy registry and tracker used to ensure accurate accounting for RECs, and he conjectured a similar system would be put in place to track the creation and retirement of RECs used for compliance with a federal RPS requirement.

Kevin Kitz asked about a sunrise date with regards to the PURPA projects and questioned whether any of the current PURPA projects would qualify for RECs. Mr. Stokes responded that many of the older projects would not be eligible under the new legislation, and pointed out that the proposed federal legislation is even more stringent than current state RPSs.

Mr.Velikoff asked whether RECs are based on power that returns to the grid, questioning the scenario where a local facility consumes the power generated. Mr. Stokes replied that this information is preliminary and additional details are still unknown with regards to a federal RPS, but stated that with hydro it is based on the actual production. Mr. Stokes stated that Idaho Power considered both the house and senate proposals to calculate Idaho Power's RPS requirement.

There was a discussion regarding the REC forward price curve and the value assigned to RECs in the portfolios. Mr. Pagoaga noted that Mr. Haener found that as California approached its 2010 RPS milestone, the market value of RECs was approximately $20 per credit; this was the amount used in the expected case. In Idaho Power's high case scenario, a $50 per MWh cap was selected because this is a legislative limit. Mr. Pagoaga reported that there is very limited data available for a long-term price curve for RECs.

Kevin Kitz asked if inflation escalation is accounted for in the price curve, and whether they are selling off surplus RECs. Mr. Stokes replied that they are accounting for their value and are not selling the surplus.

Ken Miller mentioned that he would like to see the charts depicting the various scenarios to hydro (previously provided to the IRPAC) updated based on the new legislative proposals. Mr. Stokes replied that Mr. Pagoaga could update the graph referenced without existing resources for the IRPAC. Mr. Miller stated that it might be best to wait to see where the legislation on this subject lands before investing the time to update the graph.

Mr. Kitz asked about RECs for hydro upgrades and whether they could be subtracted from the RPS requirements. Mr. Stokes replied that Idaho Power could count the net of the upgrades and receive credit for them.

With no further questions, Mr. Pagoaga concluded his presentation and stated he would continue to follow developments on the subject of a Federal RPS and would report back to the group on the subject as additional information becomes available.

Resource Portfolio Analysis – Rick Haener

Rick Haener from Idaho Power's Planning Department reported on the Resource Portfolio Analysis process. Mr. Haener explained that for the 2009 IRP, the approach was modified and the 20-year planning process was divided into two 10-year segments.

Mr. Haener explained that this analysis provides the basis for Idaho Power's requirements with regards to loads and peaks. Mr. Haener reviewed the 2009 IRP load forecast for July for the years 2009-2028 which detailed the peak hour and average annual loads and the effects of existing and new DSM to these loads.

Mr. Haener discussed the existing and committed resources that were included in the portfolios and then presented the basis for the 2009-2018 planning criteria which included:

- 17.35 million cumulative additional MWh required @ 70^{th} percentile load growth with existing and committed DSM;
- 2.66 million MWh additional annual supply needed by 2018 @ 70^{th} percentile load growth with existing and committed DSM;
- 2.87 million cumulative new REC's needed (2012 – 2018) for RPS @ 50^{th} percentile load growth and median hydro; and
- 817,000 additional REC's needed annually by 2018

A summary of the 2009 Aurora portfolio output for 2009-2018 was then presented. This analysis assumed a \$43 CO_2 adder in 2012 and ranked the various portfolios which included geothermal, wind, balanced green, solar, gas, Boardman to Hemingway, and Gateway West. Mr. Haener distributed the results of the preliminary portfolio analysis which lead to a rather lengthy discussion of the various components and calculations regarding the portfolios and the resulting rankings.

Mike Heckler suggested that the timing of the capacity factor be reordered to have the first wind coming online with a 34% capacity factor in 2012. Mr. Haener agreed to change the capacity on wind in order to factor in the timing of the resources in an effort to equally weight the numbers.
An IRPAC member asked whether it would be a good idea to run the portfolios out for 20 years since the portfolios were so close in total costs. Mr. Haener replied that the portfolios would still be subject to assumptions and stated that Idaho Power wouldn't be able to analyze all combinations/permutations.

Mr. Kitz asked how Idaho Power views the portfolios with regards to risk rankings.
Mr. Haener replied that it is reviewed for gas price risk, carbon risk, coal output reduction, high load scenarios, etc. Mr. Stokes stated that the resource portfolios presented form the base case for analysis, and the analysis still to come will be for sensitivity and risk.

Betsey Bridge stated she would like to see a portfolio that demonstrates a reduction in carbon emissions. Mr. Haener stated that in one scenario there is reduced coal output which reduces the carbon footprint. He stated that Idaho Power could review this to see what would happens if there was a 50% reduction in coal output.

Ken Miller asked if it would be possible to see a scenario with more DSM and other resources.
Mr. Stokes responded that he is not sure whether this could be accomplished given the current time table. He stated that with regards to the carbon issue, ultimately the impact will be the same; Idaho Power is short of the energy needed to serve customer load.

Kevin Kitz asked about the 100 MWh of wind in 2012. Mr. Haener responded that the portfolios are specifically designed to help Idaho Power meet an RPS, and stated that wind doesn't get us to where we need to be. The suggestion was made to raise the cost of carbon to see what impact this would have on the portfolios.

John Gardner asked how outside purchases factor into the portfolios. Mr. Haener replied that they are excluded. RECs are calculated in capital dollars excluding AFDUC. This gives a relative comparison on a fixed cost for the 10-year period. This is a different number than what the customer is going to pay.

John Velikoff asked if depreciation is included. Mr. Haener replied yes, O&M is also included.

Ken Miller asked whether they include committed resources. Mr. Haener replied no.

Mike Heckler stated that taking the average of the portfolio operating costs provides a relative difference. He stated that each has a 30 year life, so Idaho Power should include the operating costs. He asked for an explanation regarding how many MWh could be expected. This gives that total cost and value to the customer and would indicate which would be the least-cost. He further stated that the rankings are very sensitive to the numbers that are provided.

John Gardner asked whether analyzing the portfolios differently by shifting things around would make a difference in 2018. Rick replied that it would not. He added that you would need to look at 2018 in isolation.

Mr. Kitz inquired about the cost of combined-cycle combustion turbines (CCCTs) and whether they were embedded. Mr. Haener replied that there is very low margin cost on resources with regards to their production, and didn't think Idaho Power would need to model this to run the costs out.

Mark States stated that for portfolio analysis Idaho Power is looking for significant differences in the portfolios. Mr. Haener stated that by looking at year 2018 you can get to where you need to be.

The IRPAC raised the idea of extending the portfolio analysis out for another ten years since the portfolios were so close in total costs. Tom Noll provided an explanation on how Idaho Power could arrive at an extended cost amount.

Steve Munn stated that a component of the IRP process is to identify quality resources that are reliable and minimize the cost to the ratepayer.

Mr. Haener stated that we should be looking at the portfolio characteristics and the associated risks within each portfolio.

Kevin Kitz made the statement that during the first 10 years, renewables would be best, but when looking to year 2028, it would be best not to put any more into renewables and build transmission. Mr. Haener replied that this is not necessarily true.

Mr. Miller asked if the carbon price numbers remain static. Mr. Haener replied that it is important to see how the portfolios perform under these other scenarios. Mr. Stokes stated that under the Oregon IRP guidelines, utilities are required to look at higher carbon cases. Idaho Power is also looking at a reduction in coal plant output as well as natural gas price volatility. Mr. Haener stated that this gives different answers, and that Idaho Power needs to be able to differentiate between the different types of energy. Mr. Stokes asked whether providing the information in terms of dollars per MWh would be more meaningful.

Steve Munn stated that this is theoretical, but it provides a different way to look at the portfolios. Mr. Haener stated that you would need to refer to the $ per kW and divide this by the output.

Don Reading asked which line on the tables goes into the rate base, and stated that the IRPAC cares about the impact to customer rates.

Mr. Haener stated that all the portfolios are fairly balanced with regards to energy production, and that there's not much difference.

Mr. Velikoff stated that there is a large discrepancy on the balanced portfolio when compared to the other options.

Betsey Bridge stated she would like to see a portfolio that demonstrates a reduction in carbon emissions. Mr. Haener stated that in one scenario there is reduced coal output which reduces the carbon footprint. He stated that Idaho Power could review this to see what would happens if there was a 50% reduction in coal output.

Ken Miller asked if it would be possible to see a scenario with more DSM and other resources. Mr. Stokes responded that he is not sure that could be accomplished at this point in time. He stated that with regards to the carbon issue, ultimately the impact will be the same. He stated that the ultimate impact is that Idaho Power is short of the energy needed to serve customer load.

Irrigation Peak Rewards Program – Quentin Nesbitt

Pete Pengilly introduced the next two speakers, Quentin Nesbitt and Billie McWinn who presented information regarding two Demand-Side Management programs, the Irrigation Peak Rewards program and the Commercial Aggregation program. In his introduction, Mr. Pengilly stated that by this summer, Idaho Power will offer a demand response program to all customer sectors. He stated that this is very unusual because most utilities do not offer that range of demand response programs to their customers. Mr. Pengilly stated that Idaho Power anticipates that these programs will reduce the loads in the summer, hopefully eliminating or reducing the need for additional peakers in the future. He then turned the presentation over to Mr. Nesbitt who addressed the IRPAC on the Irrigation Peak Rewards Program.

Mr. Nesbitt introduced himself and provided some background information on the Irrigation Peak Rewards Program. He explained that the program has been in existence for the past four years; but has been dramatically altered from the original program of only timer options to the addition of a new dispatchable option for the updated program. Mr. Nesbitt stated that Idaho Power worked closely with the Irrigation Pumpers Association, receiving input from both the Idaho PUC and farmers in an effort to redesign the program to increase peak load reduction and customer participation in a cost effective manner. He explained that the program is not designed to be used when the price is high or to eliminate the necessity of operating existing gas peaker plants.

Mr. Nesbitt presented a graph depicting past program performance from 2004 through 2009, estimates for MW reduction, customer incentives, total cost, and participating locations.

Ken Miller asked whether Idaho Power anticipates the same increase in savings and participation going forward. Mr. Nesbitt replied that most of the increases will occur this year, with smaller increases going forward if the program works well. He stated that Idaho Power's marketing of the program has impacted the increase for this year.

Kevin Kitz asked if the customer incentive payments would continue if there are no new customers signed up and carried forward, and if this amount included the total cost of the installed hardware. Mr. Nesbitt replied that the cost includes about $5 million in hardware.

Mr. Nesbitt explained why Idaho Power chose to offer a dispatchable option in the program. He explained that with the timer option, many customers chose the 1-day a week option, and Idaho Power would schedule all customers on different days so that the load would be the same every day. This resulted in approximately the same amount of kW every day. The dispatchable option allows for scheduling for a day where there is a true need for an actual event and allows for a more significant reduction. The incentives for the dispatchable program are greater than with the timer option. Mr. Nesbitt then reviewed the specifics of both the dispatch and timer options.

Dispatchable Option (on demand load control events)

- Dispatchable load control events can occur any weekday (excluding July 4) between 2 p.m. and 8 p.m., with notice given by 4 p.m. on the day prior to an event.
- Dispatchable load control events can occur up to 4 hours per day, up to 15 hours per week but no more than 60 hours per season.
- A two-way communication device allows Idaho Power and the customer to remotely control pump(s).
- Flexibility for service points with at least 1,000 horsepower and multiple pumps.

Electronic Timer Option

- Choice to have irrigation pumps automatically turned off one, two or three scheduled weekdays per week.
- Interruption events occur between 4 p.m. and 8 p.m. on pre-determined weekday(s) depending on the demand credit option the customer chooses.

Mr. Nesbitt explained that the timer option remains basically unchanged from what has been offered in the past, but the timeframe has been shortened from June 15th to July 31st. On the dispatch option, cell phone devices are installed to control all pumps at a service location point, and will not allow the pump to run during control events. The dispatch option provides for higher incentives with fewer overall interruptions than the timer option. Mr. Nesbitt stated that a customer selecting the dispatchable option could experience an approximate 30-40% annual bill reduction. He also explained that customers can opt out of the program up to 5 times during the season, but that there is a fee of $0.005 per kWh, with an 80% reduction in credit if a customer opts out 5 times or more per season.

Don Reading asked how the program would work if the weather was very cool and wet and the device was not activated. Mr. Nesbitt explained that the customer would still receive the incentive.

John Gardner asked whether there were substantial water savings associated with the programs. Mr. Nesbitt replied that the amount of water involved is about the same.

Steve Munn asked if this program is available in both Oregon and Idaho. Mr. Nesbitt replied that it has been approved by both the Idaho Public Utilities Commission on Jan 14th and the Oregon Public Utilities Commission on February 25th.

Commercial Aggregation Program (EnerNOC, Inc.) – Billie McWinn

Billie McWinn reported that Idaho Power issued an Aggregator-Operated Commercial Demand Response program RFP in August 2008. Idaho Power chose to outsource the program operation and signed a five-year contract with EnerNOC in February 2009, contingent on PUC approval. This program was filed with the IPUC in March 2009.

Ms. McWinn explained that EnerNOC was chosen for their infrastructure advantage, established sales team, and their PowerTRAK software platform. Ms. McWinn stated that EnerNOC assumes all risk and there is no cost to the customer.

The program operates in June, July, and August, Monday through Friday (excluding holidays), from 2 to 8 p.m., and the event duration is from two to four hours. There are 20 maximum allowable events and 60 maximum allowable event hours per season. The program requires a two-hour advanced event notification.

Ms. McWinn reported that Idaho Power pays EnerNOC for energy and capacity. EnerNOC pays penalties to Idaho Power if there is a capacity performance shortfall, committed capacity shortfall, or energy performance shortfall. She explained that penalties can amount to more than the payments and are substantial if they do not perform. Ms. McWinn stressed that customer satisfaction is critical to Idaho Power, and stated that it was a big decision to go with an outside vendor because their performance ultimately reflects on Idaho Power.

Ms. McWinn explained that the customer contracts directly with EnerNOC, and customers pay no costs, fees, or penalties for performance failure or opting out of the program. However, incentives can be reduced and are based on performance.

Steve Munn asked about capacity and energy payments. Ms. McWinn explained they range from $25 - $35 per kilowatt, but that it is negotiable and dependent upon the site. She explained that EnerNOC determines the customer's performance potential without negatively impacting the customer's business. Since the customer does not pay for the infrastructure, it is in EnerNOC's best interests to keep the customer happy.

Kevin Kitz asked if there were any differences in customer usage when the PowerTRAK software is implemented. Ms. McWinn answered that having the ability to track usage is a very effective energy efficiency tool.

Mr. Kitz asked about the 65 MW maximum program cap. Ms. McWinn replied that the 65 MW cap was selected to keep it within a range that Idaho Power could plan for with the ultimate goal of reducing the need to build peaking facilities.

Ms. McWinn concluded her presentation stating that they anticipate a PUC ruling in May, with some events in 2009, and the goal of having the program fully implemented in 2010. She explained that due to timing constraints, Idaho Power intends to file in Oregon for the program next year.

Public Comments and Meeting Wrap-up – Mark Stokes

Mr. Stokes thanked Ms. McWinn and Mr. Nesbitt for their presentations and asked participants if they had any additional questions.

Don Reading asked about the automatic metering and whether the implementation of these meters could have a substantial impact on residential and commercial loads and whether Idaho Power has done any analysis to change the shape of the load. Tim Tatum replied that this is more of a time of use program and is not used for IRP planning purposes. Brad Snow added that the new programs will be reviewed in terms of carbon tax and energy credits and the resulting impact to rates.

Kevin Kitz asked a question regarding 38 aMW, 40 Peak, and the gas-fired projects that are being built. He questioned whether this will raise rates and if this is included in the load growth forecast.

Brad Snow responded that the expenses known at the time were included, and that assumptions were made regarding the RPS and carbon tax. Tom Noll stated that there are considerable differences in the capital costs of the portfolios and that capital costs are treated differently in the rate structure. Barr Smith stated that the assumptions are looped through and that the prices are embedded in the current load forecast. An IRPAC member suggested running the portfolio scenarios with the assumption that the carbon footprint would decrease over time by raising the carbon adder to reduce the carbon footprint. Rick Haener replied that there is no elasticity in the price of the carbon adder, and questioned whether the model would be any better if it could be integrated. Steve Munn stated that this would significantly raise rates. Tim Tatum mentioned that plant depreciation would be happening at the same time.

Ken Miller asked about filing for an increase in DSM and questioned if it would increase 4.75%, and if so, what would be the impact. He also questioned the need to raise more money to fund existing DSM programs. Pete Pengilly replied that Idaho Power will continue to fund both existing and new programs, and stated that it is Idaho Power's money that is being spent in these endeavors.

Mr. Stokes stated the next meeting would be on April 14th, and that the Planning Department would work to get a summary sheet of the portfolios out to participants in a format that would be more meaningful prior to the next meeting. Mr. Stokes stated that the goal is to have the sensitivity analysis completed prior to the next meeting, and he stressed the importance of keeping the process on schedule.