Inland Power and Light Company

Integrated Resource Plan
May 2008

Section 1—Executive Summary

The purpose of this section is to summarize the results of an Integrated Resource Plan (IRP) conducted by EES Consulting, Inc. (EESC) for Inland Power and Light Company (Inland). Inland is an electric cooperative utility serving approximately 37,000 members. Inland operates in a largely rural area in 13 counties in eastern Washington and northern Idaho. Inland is governed by a member elected Board of Trustees.

Inland is currently a full requirements customer of the Bonneville Power Administration (BPA) which means that BPA provides all power requirements at cost-based rates. However, Inland's power supply portfolio will change and be impacted in the future due to the following factors:

- **Initiative-937:** Chapter 19.285 RCW, the Energy Independence Act (I-937) established a renewables portfolio standard (RPS) for electric utilities. Inland must purchase 3 percent of its power requirements using I-937 "eligible" renewable energy sources beginning in 2012. The RPS target increases to 9 percent in 2016 and 15 percent in 2020. In addition, I-937 requires Inland to acquire all available conservation that is cost-effective, reliable and feasible.

- **BPA Tiered Rates:** BPA has proposed fundamental changes to the pricing structure of BPA power sales beginning in October 2011. BPA has developed two pricing tiers to capture the difference in costs associated with existing BPA resources (Tier 1), and new resources or market priced purchases (Tier 2) required to meet customers' loads in excess of the current capability of the BPA system.

- **HB 1010:** Chapter 19.280 RCW, Energy Resource Plans (HB 1010) requires Bonneville full requirements customers to submit a resource plan by September 2008. The resource plan must, at a minimum, include a 10-year load forecast, enumeration the resources that will be used to serve forecast loads, and an explanation of why the enumerated resources were chosen, including an explanation of why resources, if any, other than renewables, conservation and efficiency resources were chosen. The resource plan must be updated or revised every two years thereafter.

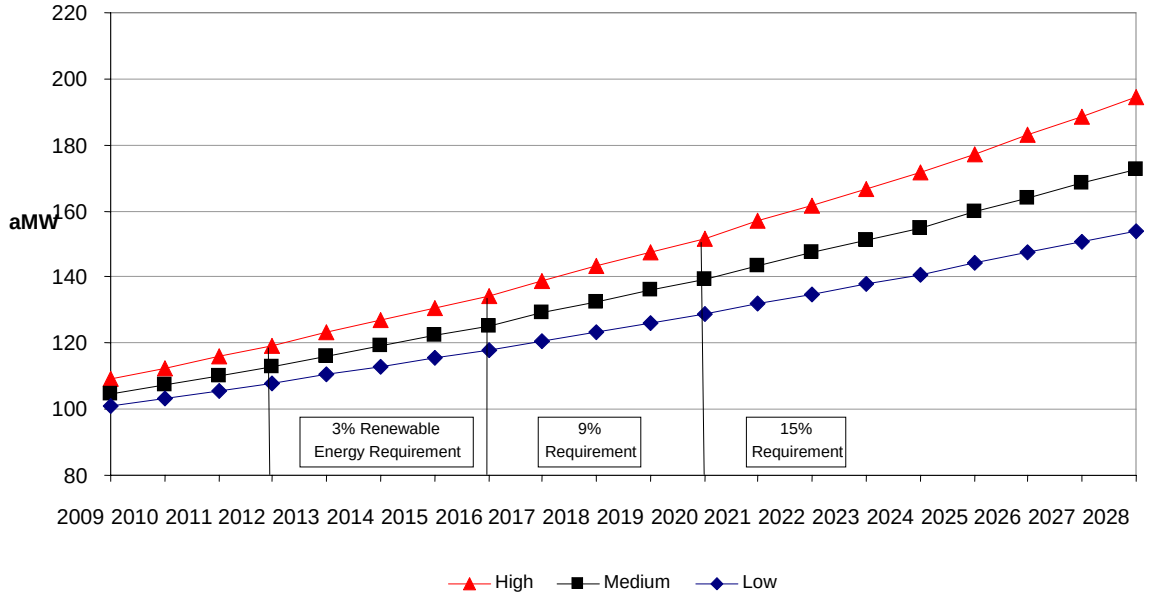
- **SSB 6001:** Substitute Senate Bill 6001 (SSB 6001) establishes statewide GHG emissions reduction goals, and imposes an emissions performance standard on new long term baseload electric generation beginning in July 2008. The law will impose significant restrictions on the procurement of fossil fuel-fired generation. Coal-fired generation (both pulverized coal and integrated gasification combined cycle technologies) produces GHG emissions in excess of the new emissions standard of 1,100 pounds of CO2 per megawatt hour. The law effectively bars Washington utilities from entering into long term financial commitments for coal-fired generation unless the project successfully utilizes some form of carbon sequestration.

Resource planning involves studying a broad range of resource alternatives including investments in energy conservation and other Demand Side Management (DSM) options, and investments in renewable and non-renewable generating resources. The IRP includes a review of these resource options.

Loads and Resources

Load is the amounts of energy Inland's members or customers require to meet their energy needs for heating, lighting, motors and other end-uses. As part of the IRP, low, base and high load forecasts were developed. The low and high forecasts were used to calculate the impact of forecast loads on the various resource portfolios considered. Figure ES-1 shows the three energy load forecasts used in this IRP. This figure also notes the I-937 renewable energy requirements.

Figure ES-1
Forecast Purchased Power Requirements - ENERGY



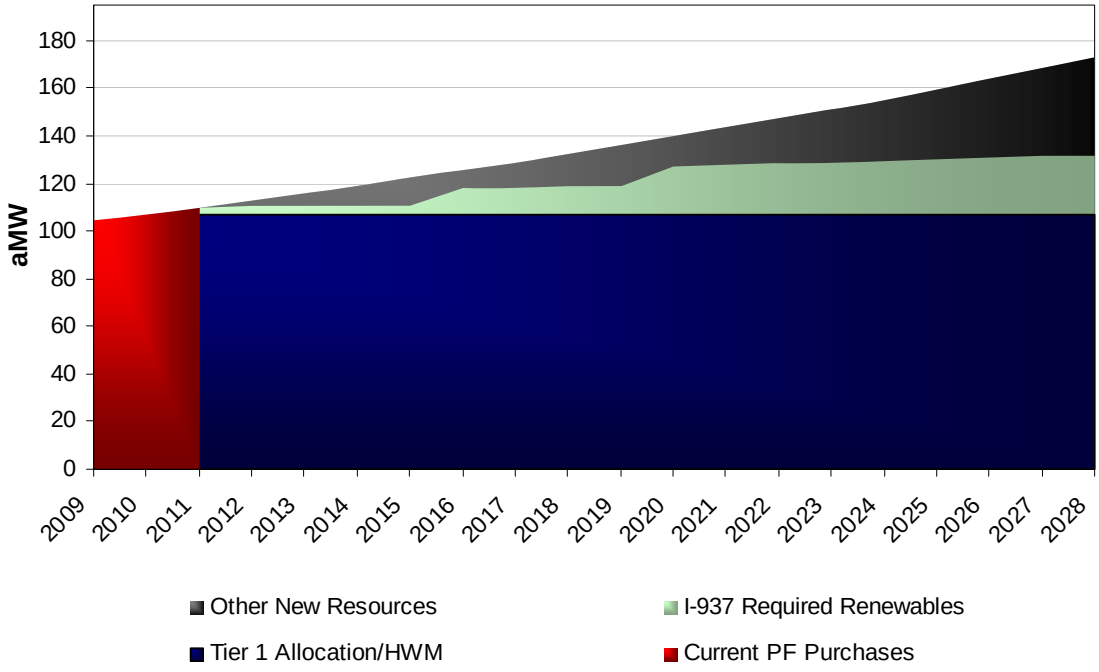
* Note: An annual average megawatt (aMW) is calculated by dividing annual energy consumption in megawatt-hours (MWh) by the number of hours in a year (8,760).

Inland currently relies on BPA for all of its power needs with the exception of a small number of distributed generation facilities on its system. When BPA implements tiered rates beginning in 2012. BPA power supply will be separated into two tiers. As currently proposed by BPA, Tier 1 purchases will be equal to Inland's actual 2010 power requirements, its High Water Mark (HWM), with adjustments for conservation and weather. As forecast Inland's Tier 1 allocation will be sufficient to serve approximately 95 percent of Inland's total projected load in 2012. Inland will then have the option of purchasing power from BPA Tier 2 rate alternatives, non-BPA sources or a combination of the two to meet its power purchase requirements above its HWM. Due to the low cost of power for existing federal (BPA) resources compared to market prices and alternative resource costs, it is assumed that Inland will elect to purchase its full Tier 1 entitlement up to its HWM. At this time, BPA's existing power resource mix is 85 percent

hydroelectric, 10 percent nuclear, and 5 percent from wind and other types of resources or market purchases.

Figure ES-2 graphically shows the base load forecast for Inland. Inland would be eligible to purchase approximately 107.2 aMW of Tier 1 power under the base case load forecast and will require increasing amounts of power above Tier 1. Inland's additional power requirements are forecast to increase from 5.8 aMW to 65.6 aMW from 2012 through 2028. The "Other New Resources" category includes new DSM.

Figure ES-2
Resource Stack Base Load Forecast - ENERGY



Demand-Side Resource Options

Two changes will impact how public utilities in Washington State deal with issues related to energy conservation. Two new laws, HB 1010 and I-937, both require reporting and documenting the amount of cost-effective conservation and efficiency resources Inland plans to achieve. The I-937 requires utilities to establish conservation targets (beginning in 2010) and then document how these targets are met.

In addition, BPA's proposal to change its rate structure by establishing a 2-tier structure gives utilities a strong incentive to compare conservation resource costs against supply-side resource costs. Increasing the amount of conservation in a utility service territory can potentially be a significant benefit to ratepayers due to the avoidance of higher priced supply-side resource purchases. Inland currently offers an array of conservation program options and participates in the BPA Conservation Rate Credit Program.

I-937 related rules allow the option of using the Northwest Power Planning Council's "Conservation Calculator" to obtain default target estimates for Washington utilities. The "Conservation Calculator" is based on region-wide conditions and while it is easy to use, it does not account for all the unique circumstances of an individual utility's service territory and retail load mix. The target level of annual conservation from the "Conservation Calculator" is 0.70 aMW for Inland. The calculator's estimated costs to achieve this annual level of conservation are $1.07 million in 2008 dollars. Recent levels of conservation at Inland include a high of 0.31 aMW in 2003 and more recently 0.12 aMW in 2007. The I-937 rules provide options for utilities to establish their own targets. Inland could set their own conservation targets by using the "Modified Conservation Calculator" or the "Utility Analysis" options included in I-937. These methods may allow the unique features of Inland's service territory to be recognized.

Inland has a unique service territory when compared to some other Northwest utilities. Many of the unique features may make conservation acquisition more difficult, including:

- Service territory is a large, sparsely populated area (approximately 5 customers per mile)
- Service territory covers multiple counties
- The customer base is predominantly residential (93 percent)
- The load is predominantly residential (79 percent)
- Possible disproportionate share of residential sector is mobile/manufactured homes
- Possible disproportionate share of residential sector is rental homes
- Notable portion of the population is considered low-income
- Overall achievability of conservation is low due to customer acceptance

In the interests of both achieving the I-937 requirements and reducing the impact of future power cost increases, Inland should actively pursue all feasible cost-effective conservation measures and programs. Cost-effective measures can play a large role in mitigating the impact of higher-cost Tier 2 rates and resources.

Federal Supply-Side Resource Options

Under BPA's current rate structure, when BPA acquires additional resources to serve its customers' increasing loads (load growth), the cost of purchasing additional power is averaged or "melded" with the cost of the existing resources. As a result, BPA's current rates reflect the average cost of both its existing and new resources. In order to serve load in excess of 2010 loads, BPA will need to acquire additional resources to augment its current resource stack.

Beginning in October 2011, Tier 1 is intended to capture the costs of BPA's current resources and Tier 2 is intended to capture the costs of additional resources acquired by BPA to serve its customers' loads in excess of their Tier 1 allocation. The general structure of the products that BPA intends to make available at Tier 1 rates will remain essentially unchanged from the products that it currently provides. The current BPA power products are Load Following, Block, and Slice.

Forecast BPA Tier 1 rates were developed assuming that BPA's rates are unlikely to decline over time. As such, low, medium, and high Tier 1 rates were developed based upon low, medium, and high inflation factors.

BPA is proposing to offer a number of Tier 2 power rate alternatives and associated features including a market-based and a renewable Tier 2 rate alternative. Load following customers will also have an opportunity to select the Shared Rate Plan (SRP) if they have committed to purchase 100 percent of their Tier 2 loads from BPA. Under the SRP approach a melded Tier 1 composite rate and Tier 2 load growth rate will be calculated and participating utilities will purchase power at one rate.

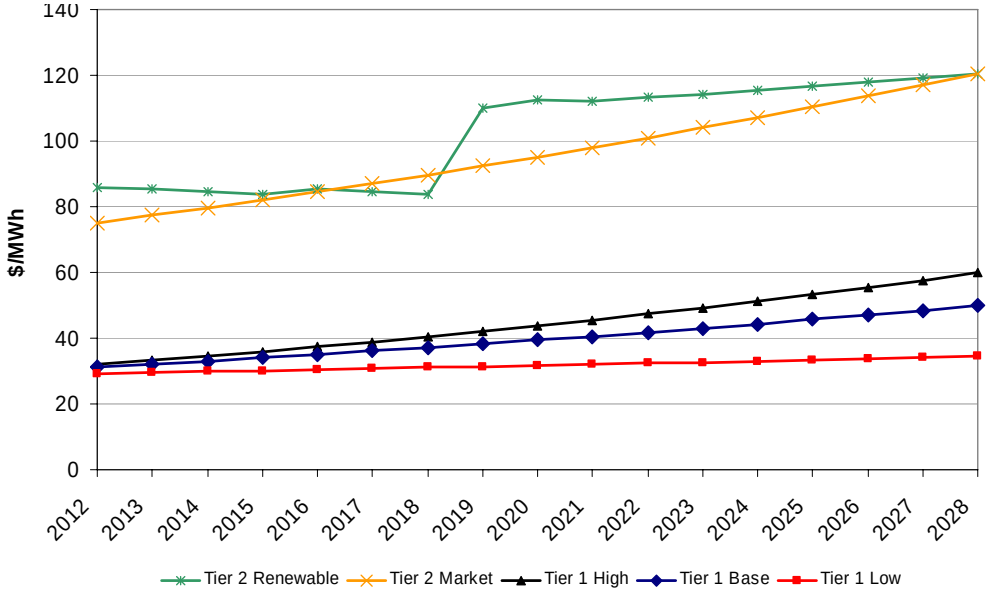
For this study, the following Tier 2 rate forecasts were developed:

- Tier 2 Vintage Renewable: Includes wind firming and integration costs, operation and maintenance costs, wind capacity factors, the federal production tax credit and capital costs based on current market prices for equipment and construction costs and a borrowing rate of 6 percent and a borrowing term of 20 years. The cost increase in 2018 shown in Figure ES-3 below is due to the expiration of the Production Tax Credit (PTC) which is only applicable during the first ten years of operation. The analysis assumes the renewable project begins commercial operation in 2009 and, as such, the PTC expires at the end of 2018.

- Tier 2 Market: Includes forecast market prices based on a snapshot of forward Mid-Columbia market prices. It should be noted that forward market prices are volatile and change hourly. Actual market prices depend on the time of the transaction.

Figure ES-3 demonstrates the lower cost of Tier 1 resources compared to both Tier 2 renewable and Tier 2 market price forecasts. The advantage of a Tier 2 renewable product over a Tier 2 market-based product is that the Tier 2 renewable product could be used to meet I-937 targets beginning in 2012.

Figure ES-3
BPA Tier 1 and Tier 2 Forecasts
Nominal Dollars



On a preliminary basis EESC has concluded that the Slice and Block products are unlikely to be a reasonable match for Inland given the significant increase in complexity and operational responsibility these products entail for the purchasing utility. After consulting with Inland staff, it was determined that this IRP should focus on BPA's Load Following product which is most commonly used by BPA's small and medium sized utility customers. Subsequent analysis of this matter may be warranted should significant changes occur in policy and contractual matters associated with BPA's long term power supply arrangements.

Non-Federal Supply-Side Resource Options

Non-federal supply-side resource options include a wide array of generation technologies and market mechanisms. Generation technologies include fossil-fueled resources (e.g., gas-fired and coal plants), nuclear, and renewables (e.g., wind, solar, geothermal). Wholesale market purchases are also included as a supply-side resource option. The impact of Renewable Energy Credits (RECS) and Production Tax Credits (PTCs) on resource costs is also included. Power pool participation through which utilities join forces with other utilities in power resource acquisition is another possible option.

The first step in the development of resource strategies is an initial screening of both demand- and supply-side resource options on the basis of levelized costs. A levelized cost basis allows for the comparison of options with different useful lives on an equal footing.

Estimated cost information for both renewable and non-renewable resources is based on current market prices for plant equipment and a survey of published resource planning studies. The Council's 5th Power Plan (updated January 2007) and IRPs developed by regional utilities in the Pacific Northwest in 2007 were surveyed to provide a benchmark for capital, fixed and variable O&M, and environmental mitigation costs. Due to recent technological advancements in wave and tidal powered generation, studies from the Electric Power Resource Institute (EPRI) were employed to estimate the cost of wave and tidal powered generation. Cost estimates were reviewed by internal EESC engineers to ensure that the cost assumptions are consistent with current market construction costs for the various resources considered. Using this data, average costs were calculated and used as estimates for base case resource costs.

Non-Renewable Resources

Non-renewable resources considered include coal, Integrated Gasification Combined Cycle (IGCC), nuclear, Combined Cycle Combustion Turbine (CCCT), Simple Cycle Combustion and Turbine (SCCT). Fuel costs associated with these resources were based on average fuel prices included in regional studies and published forward natural gas prices.

Renewable Resources

Renewable resources considered include wind, wave, and geothermal, landfill gas, biomass cogeneration, dairy-based anaerobic digesters and solar. The benefit of renewables lies in the expectation that most resource options have environmentally appealing aspects. In addition, renewable projects can provide protection against fuel price risk. Renewable projects also

provide diversification of fuel consumption limiting the risks associated with relying on one type of fuel which may have volatile prices.

Increasing renewable energy requirements under California, Oregon and Washington renewable portfolio standards will only add to the increased demand and scarcity of supply, making it increasingly difficult and costly for utilities like Inland to find power purchase agreements from renewable generation projects. Futhermore, it should be noted that I-937 provisions impose a significant artificial barrier to the acquisition of renewable resources, particularly wind resources, located outside the Pacific Northwest. In addition, the cost of wind power is currently driving the renewable energy market as other renewable technology project owners tend to price their power near the price of wind projects when negotiating power purchase agreements.

Renewable Energy Credits (RECs)

RECs, also known as "green tags", are market mechanisms that represent the environmental benefits associated with generating electricity from renewable resources. In states that have a REC program, renewable energy providers are credited with one REC per year for every 1,000 kWh of renewable energy produced. The renewable energy is then fed into the electrical grid, and the accompanying REC can then be sold on the open market. A REC market has been developed to support the development of renewable resources. A utility with a renewable resource that does not need to keep the full "green value" of its renewable resource has the option of marketing the "green aspect" of its resource by selling RECs. RECs can be sold to other utilities that do not have sufficient renewable resources in their portfolios to allow utilities a means of including "virtual" renewable resources in their power supply portfolios.

The current wholesale value of a REC is in the range of $5/MWh to $12/MWh. For purposes of the IRP base case, it is assumed that Inland will sell RECs surplus to its I-937 requirements on a wholesale basis at a base case 2008 price of $7.73/MWh. The revenues from REC sales diminish as Inland's I-937 mandated renewable energy purchase targets increase from 2012 (3 percent) to 2016 (9 percent) to 2020 (15 percent). In post-2011 Inland will also likely have surplus RECs in most years due to renewable energy quantities that are purchased based on forecast load requirements that do not exactly match Inland's actual requirements in a given year.

For the non-renewable resources included *in the screening analysis*, it is assumed that Inland will purchase enough RECs to meet its I-937 targets beginning in 2012. The REC costs associated with the non-renewable resources increase as the I-937 targets step up to 9 and 15 percent in 2016 and 2020, respectively. The REC costs are included in the 20-year levelized costs shown below in Figure ES-4.

Production Tax Credits

The Energy Policy Act of 2005 provided for the renewal of the Production Tax Credit (PTC) for renewable resources placed in service by December 2007. In December 2006, Congress extended the PTC so that renewable resources placed in service by December 2008 are eligible. In its current form, the PTC provides a credit of 1.9 cents/kWh of actual energy generated

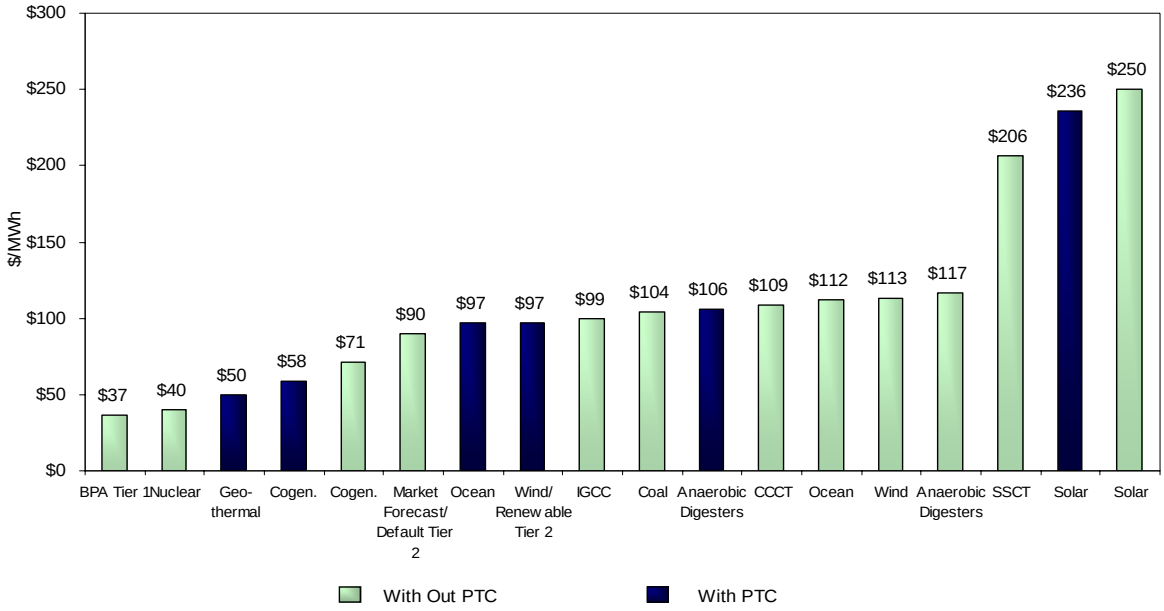
applicable to the first 10 years of operation. Currently, PTC legislation is being reviewed by Congress. The latest proposed PTC extension is through December 2009.

The IRP base case assumes that all I-937 eligible renewable resources will be eligible for the PTC. However, the PTC would only be applicable for the first ten years of commercial operation. Due to the uncertainty of acquiring power from a renewable resource that has qualified for the PTC, renewable project costs are analyzed with and without the PTC.

20-Year Levelized Cost Projections for Screened Resources

Figure ES-4 summarizes the nominal 20-year levelized costs of the supply-side resources considered in the screening analysis. Forecast BPA Tier 1 rates are included for comparison purposes. Renewable resource costs are shown with and without the federal production tax credit. The PTC is a significant cost factor as illustrated by the fact that wind power with the PTC has a lower cost than a CCCT, IGCC and coal and a higher cost if the project is not eligible for the PTC.

Figure ES-4
Resource 20-Year Levelized Costs
2008 Dollars



Power Pool Alternative

As an alternative to acquiring resources on its own, Inland should give careful consideration to participating in a power pool to meet future resource requirements. Power pools allow for greater efficiencies as member utilities share the administrative and capital costs burdens associated with new resources. Going it alone allows for the greatest flexibility regarding resource type and location. However, going it alone does not allow utilities to take advantage of economies of scale and scope. In addition, scheduling and purchasing power in increments of at least 25 megawatts can result in savings via economies of scale. Buying and selling power on the open market in relatively small pieces can be administratively burdensome and result in paying premiums for purchases and related services.

Because power pools allow for larger purchase quantities they also allow for greater resource diversity. Acting alone, Inland would have to purchase small amounts of multiple resources in order to diversify its power supply portfolio. The small purchase quantities would pose scheduling difficulties and Inland would likely pay high premiums for both the small amounts of power purchased and scheduling services. A power pool would allow for a group of utilities to purchase relatively large amounts of power from a pool of diverse resources. The diversity of the resource pool would lessen the group's risk exposure. The "go it alone" option may be the only option for utilities that are unable to find utilities with similar resource needs, funding and/or proximity. Inland is currently exploring opportunities to participate in a non-federal power pool.

Resource Portfolios and Strategies

Based on the screening analysis, resource strategies are developed in order to compare the options for meeting Inland's load requirements above Tier 1 with different resource combinations. These strategies are designed to assess the impact of different resource combinations.

Based on the results of the screening analysis, seven resource strategies were identified for further analysis. The base case for each portfolio assumes Inland will expand the current level of DSM programs up to the base case of 0.35 aMW per year (as discussed in the "Demand-Side Resource Options" section). The strategies developed include the following:

- Portfolio 1: BPA Tier 1 plus Market Purchase or Short-Term Tier 2
- Portfolio 2: BPA Tier 1 plus Purchase of Output from Wind Resource or Tier 2 Vintage Wind Resource
- Portfolio 3: BPA Tier 1 plus Combination of Wind Resource and Market Purchase
- Portfolio 4: BPA Tier 1 plus Purchase of Output from CCCT Resource
- Portfolio 5: BPA Tier 1 plus Combination of a Wind Resource and a CCCT Resource
- Portfolio 6: BPA Tier 1 plus Purchase of Output from Coal Resource
- Portfolio 7: Least Cost Portfolio (includes BPA Tier 1 plus Purchase of Output from Coal Resource and High Level of DSM)

All seven strategies assume Inland purchases its full Tier 1 allocation from BPA. Portfolios 1 through 6 assume base level DSM while Portfolio 7 assumes a high level DSM resources. The base level of DSM provides 0.35 aMW per year at a 20-year levelized cost of $40/MWh, while the high level of DSM provides 0.55 aMW per year at a 20-year levelized cost of $48/MWh.

Portfolio 7 (Least Cost Portfolio) is included to provide a benchmark of what Inland's power costs could be absent recent legislative mandates regarding the purchase of output from coal-fired resources. This scenario includes coal as the preferred resource to serve load growth above Inland's Tier 1 allocation. In reality, due to I-937, SSB6001 and the potential for future costs and risks associated with abating greenhouse gases and carbon emissions, the purchase of output from a coal project is not a realistic option. Portfolio 6 assumes that the cost of coal would include the impact of carbon dioxide mitigation costs and other regulatory challenges and risks facing coal-fired power projects.

Scenarios utilizing nuclear, ocean power, geothermal, IGCC resources, and an SCCT were not developed for several reasons. It is unlikely that power from new nuclear, geothermal and ocean power resources will be available for purchase by 2012. Carbon sequestration technology for IGCC plants is not fully developed, and several regulatory hurdles exist for this technology. Lastly, the overall costs calculated in the screening analysis for SCCT resources were high compared to the other resource options available to Inland.

Figure ES-5 demonstrates that given the base case assumptions, and excluding the Least Cost Portfolio, Portfolio 1 (Market Purchases) is the lowest cost portfolio. However, the 20-year levelized costs for portfolios 1 through 6 are not significantly different. The cost spread between the portfolios is not significant because the bulk of power purchases are made at forecast Tier 1

prices in all portfolios. Over the 20-year period 80 percent of energy is purchased at Tier 1 rates assuming the base case load forecast.

Figure ES-5
Portfolio Costs 2008 Dollars
Base Case Assumptions

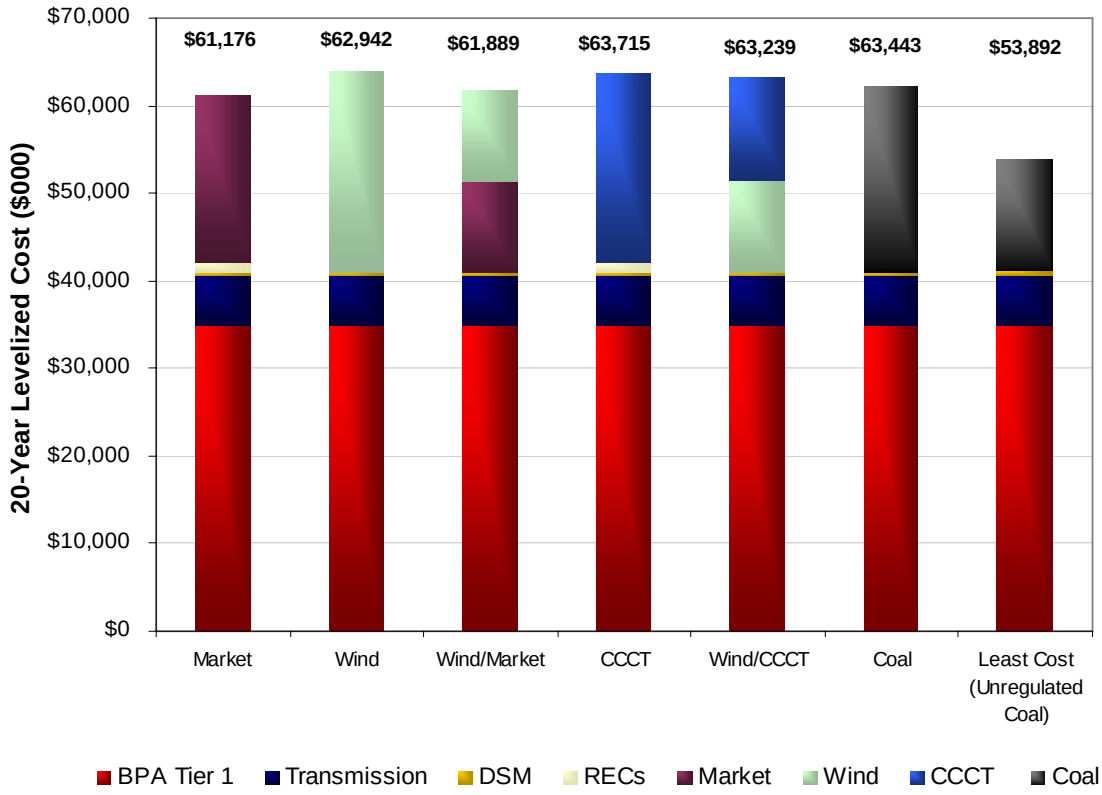
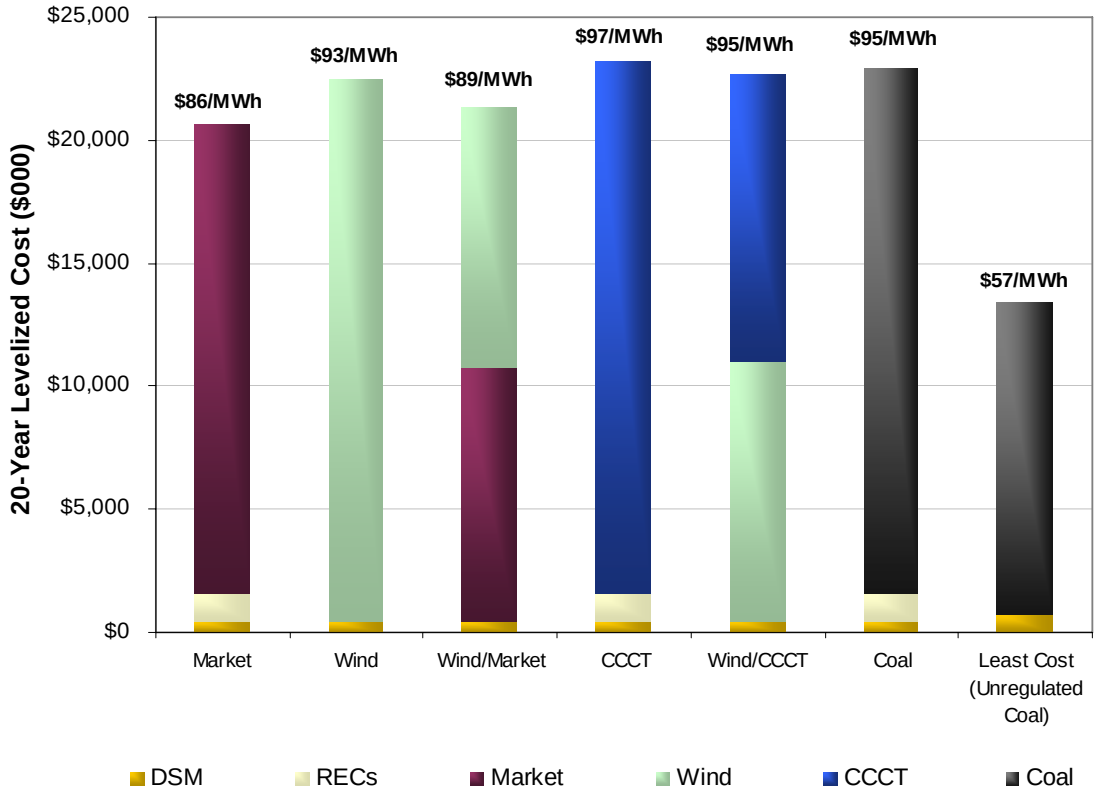


Figure ES-6 compares levelized portfolio costs above Inland's BPA Tier 1 resource costs. The values shown are 20-year levelized costs for the supply- and demand-side resources used to serve load above Inland's Tier 1 supply. Since DSM resources are generally less expensive than supply-side resources, including DSM to the mix lowers the average cost slightly. As, such the levelized costs are slightly lower than the costs for the supply-side resources on a stand-alone basis since DSM costs and savings are included.

Figure ES-6
Portfolio Costs 2008 Dollars
excluding BPA Tier 1 and Transmission Costs



Risk Assessment

Resource costs include uncertainties with respect to capital costs, operating costs, fuel costs and unit reliability and facility operation projections. In addition to these issues that resource planners have been dealing with for decades, resource planning now includes the consideration of environmental costs such as green house gases (GHG), potential carbon taxes and the operating characteristics of new resource technologies.

Each portfolio includes a combination of different risks. As a consequence, risk assessment methodology generally does not identify the optimal resource strategy but does identify the resource strategies with the greatest risk exposure. The first step in risk assessment is to identify the risks that Inland may face depending on the strategy selected. The quantitative risks included in our assessment are:

- Retail load growth forecast variations
- Electricity market price fluctuations
- Fuel price fluctuations
- Renewable Portfolio Standards requirements
- Availability of tax incentives for renewable resources

- Environmental adder costs
- REC markets
- DSM resource achievement and availability
- Wind firming/integration costs
- Wind capacity factors

Figure ES-7 below shows the relative risk level of each of the resources included in the portfolios.

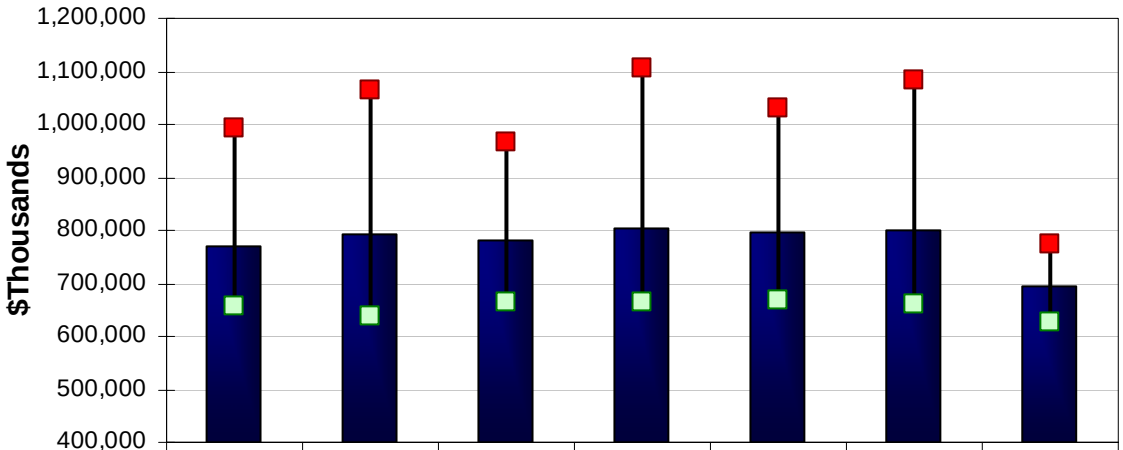
Figure ES-7
Summary of Risk Levels Associated with Resource Alternatives

Resource Type	CCCT	Coal	IGCC	Wind	Market	Energy Efficiency/ DSM
Fuel Price Risk	High	Medium	Medium	Low	Medium	Net Reduction
Development Risk	Low	High - Siting/ Regulatory Challenges	High - Immature Technology	Low	NA	Flexible/ Divisible
Environmental Impact	Medium	High	Medium	Low	Medium Low	Low or Net Positive
Operations	Dispatchable	Baseload	Baseload	Intermittent	Baseload	Depends on Measure

Quantitative risks can be defined by a range of values which are summarized below in Figure ES-7. The high cases for each portfolio includes all high cost assumptions with respect to fuel and market prices, environmental adders, wind firming/integration costs, RECs, and wind project capital costs. The high cases also include low wind capacity factors, no extension of the production tax credit and the low case for future DSM investments. The low case for each portfolio includes the low cost assumptions, high wind capacity factors, an extension of the production tax credit (also true in the base case) and the high case for future DSM investments.

The Least Cost Portfolio was included in the analysis for benchmarking purposes. The variations in 20-year NPV costs shown below in Figure ES-8 for this portfolio are solely due to variations in retail load growth. This portfolio was not subjected to sensitivity analysis via variations of the other quantitative risk factors identified above.

Figure ES-8
Total Risk
20-Year NPV 2008 Dollars



	Market	Wind	Wind/Market	CCCT	Wind/CCCT	Coal	Least Cost (Unregulated Coal)
Base	770,404	792,649	779,388	802,380	796,393	799,865	692,601
High	992,108	1,064,335	964,759	1,104,435	1,029,282	1,082,851	772,834
Low	657,622	638,816	664,681	664,737	667,688	659,305	626,207

Aside from the Least Cost Portfolio, Portfolio 3 with combination of the purchase of output from a wind project and a market purchases has the lowest risk. This lower level of risk is attributed to both the diversification of the portfolio and no REC market risk. Portfolio 3 includes the purchase of output from a wind project equal to Inland's I-937 requirements, so RECs are neither bought nor sold.

Recommended Resource Strategy

The risk assessment step provided the following information:

- Portfolio 2 (Wind), Portfolio 4 (CCCT) and Portfolio 6 (Coal) have the greatest risk exposures due to variabilities with respect to capacity factors, capital costs and the extension of the PTC for wind, natural gas (fuel) costs, REC prices and environmental regulations for the CCCT and REC prices and environmental regulations (most notably carbon dioxide) for coal.

- The risk of cost variabilities is lessened with diversified portfolios such as Portfolio 3 (Wind/Market) and Portfolio 5 (Wind/CCCT).

- Portfolio 1 (Market) is exposed to REC market and wholesale market price risks.

- The risks associated with Portfolios 1 (Market) and 4 (CCCT) are lessened when wind is added to the resource mix as in Portfolios 3 (Wind/Market) and 5 (Wind/CCCT).

- The inclusion of high conservation levels generally reduces risk exposure because DSM effectively displaces higher cost supply-side resources such as wind, CCCT, coal and market power purchases.

The salient point made above is that a diversified resource portfolio reduces risk exposure. Relying solely on wind power, market power, coal power or a CCCT to serve load above Inland's Tier 1 allocation results in risk exposure that is greater than the risk exposure of a more diversified resource portfolio.

Portfolio Recommendation: Portfolio 3 (Tier 1 Allocation plus Wind/Market)

Based on the risk analysis detailed above, Portfolio 3 (Wind/Market) is recommended. This entire portfolio can be purchased from BPA utilizing a combination of the proposed short-term and vintage resource Tier 2 products. Alternatively, Inland's load requirements above its Tier 1 allocation could be served entirely by a non-federal wind resource and wholesale market purchases.

RPS requirements under California, Oregon and Washington laws have added to the increase in the demand for and scarcity of renewable generation. Wind developers are reporting that the limited supply of labor and turbines compared to the demand for these items is driving up project costs. The cost escalation is likely to continue in the near term. In addition, the most advantageous sites for locating wind turbines are being developed first. The I-937 limitation to out of region wind purchases should be addressed to increase Inland's access to wind resources with high capacity factors and potentially lower unit costs.

Conservation Recommendation: Maximize Cost-Effective Conservation Expenditures

In addition to a combination of wind and market purchases per Portfolio 3, Inland should seriously consider increasing its conservation efforts to incorporate as much cost-effective conservation as possible given its specific service territory and retail customer mix. This would reduce the amount of energy and demand purchased from comparatively high cost wind and market power.

Action Plan

Given the numerous ongoing activities that will change the Pacific Northwest power supply landscape, Inland will be advantaged by preserving its resource options in the short-term. To this end Inland should focus its short-term planning efforts during the next five years on the following:

- Continue to follow the BPA Tiered Rates Methodology process and monitor the impact on Inland. Continue to participate in the regional discussions relating to the development of tiered rates and, to the extent possible, shape the policy to continue to meet Inland's goal of acquiring power supply in the most reliable and cost-effective manner.

- Assess power purchase requirements above BPA's Tier 1 allocation when more information is available and the final allocation methodology has been determined.

- Explore Pooling or Joint Resource Acquisition Opportunities. It will be advantageous to work with a group of similarly sized BPA customer utilities to issue a joint RFP for Tier 2 power supply. This RFP would be submitted to select non-federal suppliers to determine if there is a provider that can supply renewable power that will be compete with the BPA Tier 2 supply option and allow Inland to meet its I-937 requirements.

- Continue to stay abreast of regional resource developments and forecast resource costs. State, regional and national policies will influence the type and cost of new resources available.

- Assess resource requirements that result from new or revised State or Federal requirements.

- Explore opportunities within the region to purchase from renewable (wind, geothermal, solar, biomass) projects as opportunities present themselves.

- Assess additional conservation opportunities: A detailed DSM evaluation study and related assessments should be performed by January 1, 2010 per I-937 to explore the specific programs that are well suited to Inland's residential, commercial and irrigation customers. The DSM project evaluation method should be updated as more information becomes available regarding the structure and cost of Tier 2 power and non-federal supply-side resource options. An increase in Tier 2 rates and non-federal resource costs could make some borderline DSM projects become cost-effective.

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