9. Generating Resource Findings, Conclusions & Recommendations

This chapter describes the Council's findings, conclusions and recommendations regarding generating resource development over the period of the plan.

Generating Resource Development Criteria

The highest priority resource for meeting future needs is cost-effective conservation. The Council recommends development of generating resources only if equally cost-effective conservation is insufficient to meet need, or if generating resource development in advance of need will secure a cost-effective lost opportunity project, or if the development of a generating project appears to be the best course of action to resolve uncertainties associated with a promising generating resource.

The approach used in this plan to the assessment of need and cost-effectiveness of new generation has been refined from approaches used in earlier plans. The selection and timing of resources is based on the tradeoff of the system cost and risk consequences of adding the resource to the Northwest power system. New resources are tested in the context of the power system using the portfolio risk model described in Chapter 5. Important uncertainties are explicitly modeled. These include future loads, imports at wholesale market prices as alternatives to new resource development, exports at wholesale market prices as a source of revenue, fuel price uncertainty and volatility, hydro generation, effects of global climate change policy and resource development incentives. The result is believed by the Council to be a greatly improved understanding of the costs and benefits of resource timing and selection.

Because of data requirements and model run time considerations, the portfolio analysis is limited to new resource options having the potential to become significant players during the 20-year period of the plan. Generating resource options selected for the portfolio risk analysis are those forecast to have reasonably competitive costs during the period of the plan, reasonable prospects for successful development and operation and sufficient quantity to measurably impact overall system costs. These resources, described in Chapter 3, include natural gas combined-cycle gas turbines, natural gas simple-cycle gas turbines, wind power plants, coal-fired steam-electric power plants and coal-fired gasification combined-cycle power plants. Potential new coal and wind resources in eastern Montana are modeled with the costs of upgrading lon-distance transmission needed to bring their output to regional load centers. Also included are natural gas fired cogeneration plants sited in the Alberta oil sands region with new high voltage DC transmission to the Northwest region.

Other generating resources, though unlikely to provide bulk energy supply and not evaluated in the portfolio risk analysis may become cost effective during the period of the plan. These, also described in Chapter 3 include industrial and commercial cogeneration projects, projects using biomass residue fuels, the occasional small hydropower or geothermal project, solar photovoltaics to serve small isolated loads and simple-cycle gas turbines or reciprocating engine-generators for peaking or emergency service. Though these were not specifically assessed in the portfolio analysis, they should be identified as they available and acquired if economic.

Uncertainties

The uncertainties and assumptions associated with future load, electricity markets, fuel prices and hydro generation are described in Chapter 2. This section describes three additional uncertainties of particular importance to generating resource choice.

Global climate change

The preponderance of scientific opinion, based on empirical data and large-scale climate modeling holds that the Earth is warming due to atmospheric accumulation of carbon dioxide, methane, nitrous oxide and other greenhouse gasses. The effects of warming may include changes in atmospheric temperatures, storm frequency and intensity, ocean temperature and circulation, and the seasonal pattern and amount of precipitation, with the effects more pronounced toward the poles. Possible beneficial aspects to warming, such as improved agricultural productivity in cold climates, on balance appear to be outweighed by adverse effects including increased frequency of extreme weather events, flooding of low-lying coastal areas, ecosystem stress, increased frequency and severity of forest fires and extension of the ranges of warm climate disease vectors. Coloring this are significant uncertainties regarding the rates and ultimate magnitude of atmospheric warming and its effects.

The regional effects of climate change are less well understood. Global models seem to agree that Northwest temperatures will be higher, but they disagree regarding levels of precipitation. Current thinking by Northwest scientists leans towards a warmer and wetter climate. The proportion of winter precipitation currently falling as high elevation snow is expected to decline and peak runoff expected to shift from springtime to late winter. Summer flows would decline. The warming trend would lead to a relative decline in winter electricity demand and an increase in summer peaks.

The increasing atmospheric concentration of greenhouse gasses appears to be largely attributable to the production of carbon dioxide (CO_2) by combustion of fossil fuels. Nationwide, the power system is a prime contributor, responsible for about 39% of U.S. anthropogenic CO_2 production in 2002[1]. Any significant reduction of greenhouse gas production would require substantial reduction in net power system CO_2 production. This could be achieved most effectively by a combination of improved end use efficiencies, improved fossil plant thermal efficiencies, addition of generating resources having low or no production of CO_2, and CO_2 sequestration. Because it is unlikely that significant reduction in power system CO_2 production can be achieved without at least a moderate increase in cost, future climate control policy presents an uncertain cost risk to the power system.

Because of the high proportion of hydropower in its resource mix, the Northwest is somewhat less sensitive to climate change policy than systems more dependent on coal. However, it would

[1] U.S. Environmental Protection Agency. Inventory of U.S. Greenhouse Gas Emissions and Sinks1990 - 2002. April 2004.

be unwise to ignore the effects of possible climate change policy actions when assessing the cost and risk implications of future resource choices. For this reason, the portfolio risk assessment of this plan considers the cost and risk effects associated with future climate policy. Northwest power system faces climate change uncertainties in addition to greenhouse gas policy. These are the loss of natural hydro storage in the form of snow and shifting of the peak loads from winter to summer. Information regarding possible changes in seasonal Northwest temperatures and hydrologic patterns are being developed by the Climate Impacts Group at the University of Washington[2], but were not sufficiently complete to permit consideration of these uncertainties in the draft plan.

Analytical consideration of the effects of climate change requires plausible estimates of the timing and magnitude of possible climate change actions. The current state of climate change policy was summarized for the Council by Dr. Mark Trexler of Trexler Climate + Energy Services.[3] **(Add link in footnote)** He noted that while the United States is not a signatory to the Kyoto Climate Protocol which establishes targets for reduction of greenhouse gas emissions, there is a good deal of climate policy action both in the US and internationally. Canada, for example, has signed on to Kyoto, and compliance is a significant factor in Canadian energy policy. Elsewhere, a pilot cap-and-trade system for carbon dioxide is to be implemented in Europe in 2005 with a mandatory system in place by 2008[4].

Here in the United States, half of the states have or are developing climate change mitigation strategies. Oregon, Massachusetts, New Hampshire and Washington require offsets of CO_2 produced as a result of power generation.[5] The governors of the West Coast states have also initiated an effort to address a common regional policy. Nationally, the United States Senate in late 2003 came within a very few votes of passing the McCain-Lieberman bill that would have established a cap and trade system for the United States.[6] CO_2 reduction appears to be one of the primary drivers of efforts to reauthorize the federal renewable energy production credits and to expand state renewable portfolio standards and other renewable energy incentives.

Dr. Trexler presented three scenarios for climate change policy. One scenario portrayed collapse of efforts to implement climate change policy. He viewed the probability of this to be low. A second scenario looked at the likelihood that a combination of factors would generate the political will to seriously tackle climate change. He viewed the probability of this as “modest” although perhaps somewhat greater than the probability of total collapse of climate change mitigation efforts. The third scenario was one that postulates that the issue will not go away and that there will be continue to be efforts to enact mitigation policy. He viewed the likelihood of this scenario to be high.

The Council’s estimates of plausible cost of future climate control policy were guided by current state CO_2 offset requirements, the conclusions of a May 2003 Council-sponsored workshop, a June 2003 MIT study of the cost of implementing the McCain-Lieberman proposal[7] and an

[2] http://cses.washington.edu/cig/
[3] Link to Trexler presentation 4/08/04
[4] Define Cap and Trade
[5] Reference these actions.
[6] S139
[7] Massachusetts Institute of Technology Joint Program on the Science and Policy of Global change. Emissions Trading to Reduce Greenhouse Gas Emissions in the United states: The McCain-Lieberman Proposal. June 2003.

August 2003 MIT study of the costs of CO2 sequestration[8]. A cap and trade allowance system, as in the McCain-Lieberman proposal and as effectively used for control of sulfur emissions appears to be the most cost-effective approach to CO2 control. Because of modeling limitations, however, a fuel carbon content tax in $/TonCO2, was used to model the cost of climate change policy. The results are believed to be representative of any effort to control CO2 production using carbon-proportional constraints on both existing and new generating resources.

We have modeled carbon dioxide control costs ranging from zero to $30/ton of CO_2 emissions beginning as early as **2005 (2008??)** and with the possibility of change every 4 years. Thus some futures will have no carbon tax; a (very) few will have $30/ton in beginning in **2005 (2008??)**, and the rest will represent other possibilities between those extremes. Based on Dr Trexler's scenarios, the estimated probability of some level of CO2 control (i.e, a non-zero cost) by the end of the planning period (2024) is about **80% (50%??).** The lower bounding value for the non-zero cases is less than $1.00/ton, on the order of current Oregon or Washington offset requirements, but here applied to all fossil resources. The high-end bounding cost of $30/ton is the mid-point estimate of CO2 offset costs for the 2010 - 2025 period proposed by the Council's May 2003 workshop. While less than the cost of some scenarios of the MIT assessment of McCain-Lieberman, it is higher than many CO2 sequestration cost estimates of the second MIT study. Because of the great uncertainties regarding the aggressiveness of possible climate change policies and the cost to achieve the policy objectives, we assume non-zero outcomes to be equally probable across the range. Possible revenues generated by a CO2 tax are assumed to flow out of the power system (e.g., are not used to subsidize low-carbon resources). The distribution of outcomes over the study period is illustrated in Figure 9-1.

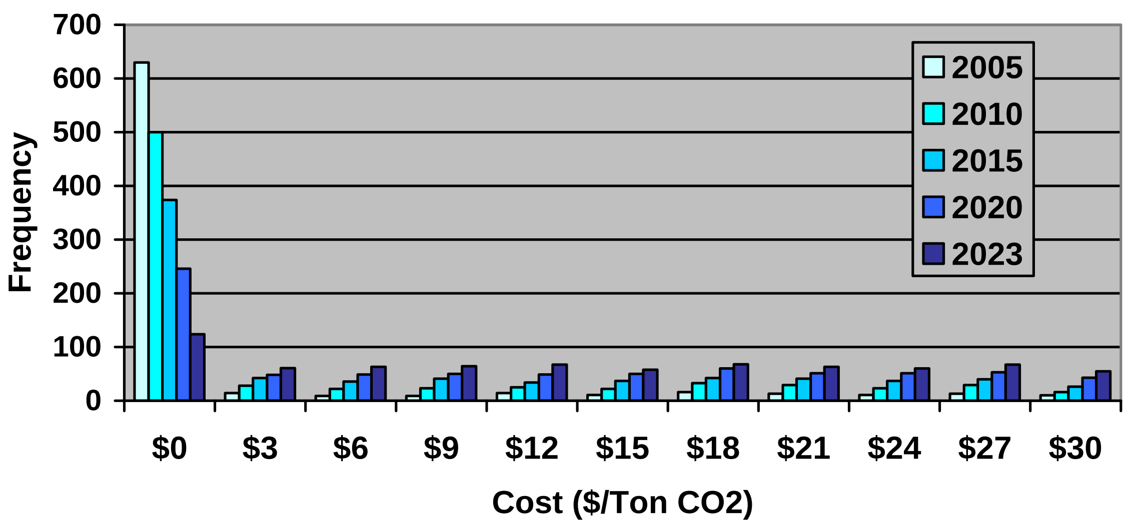

Figure 9-1: Carbon dioxide cost over the 20-year plan

[8] Massachusetts Institute of Technology Laboratory for Energy and the Environment. The Economics of CO2 Storage. August 2003.

Federal Renewable Energy Production Tax Credit

Resource development incentives can influence the apparent cost and risk benefits of resources to which they apply. The most important of these incentives is the federal renewable energy production tax credit and the companion renewable energy production incentive for tax-exempt entities. Originally enacted as part of the 1992 Energy Policy Act, as a means of commercializing wind and certain biomass technologies, these incentives, amounting to approximately $12/MWh on a levelized basis (year 2000 dollars) have been repeatedly renewed and extended, even after the target technologies have commercially matured. Recent extensions are likely to have been driven as much by climate change and local economic development concerns as by commercialization. Though the federal production incentives expired in 2003, it appears likely that they will be reauthorized in federal energy legislation. The longer-term fate of the production credit is less certain. While we expect reauthorization and possibly expansion to resources other than wind and closed-cycle biomass in the near-term, it seems likely that pressure to reduce the federal deficit will eventually force reduction or termination of the incentive, especially as the target technologies become more competitive and especially if general CO_2 control measures are enacted.

The Council has modeled the renewable energy production incentive as applicable to windpower at its most recent levelized value in $/MWh, escalating with inflation. The probability that the credit will exist is assumed to decline over time (Figure 9-2). In addition, the credit is linked to climate change policy assumptions and is assumed to discontinue if any level of CO_2 control is enacted.

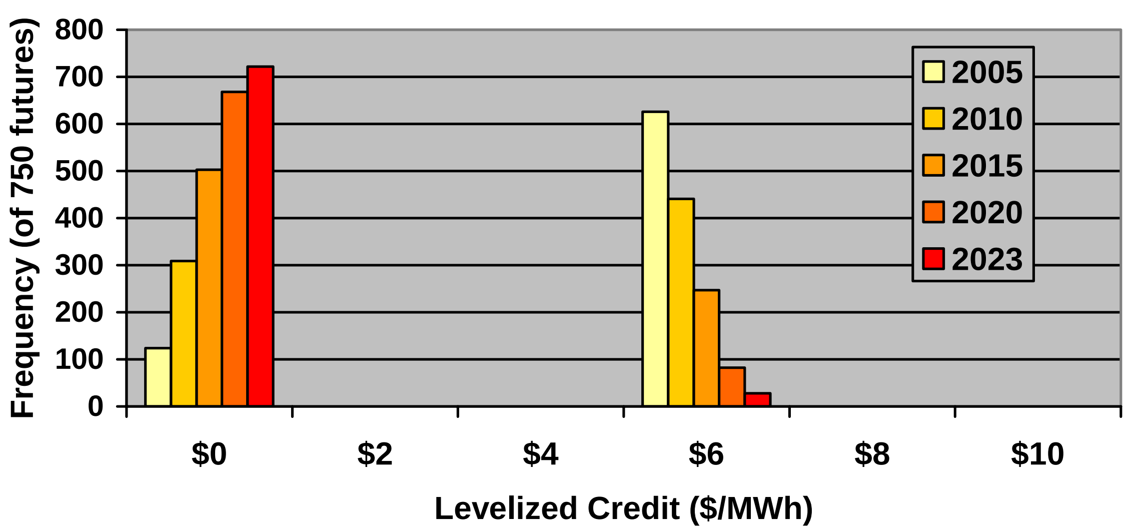

Figure 9-2: Renewable energy production credit over the 20-year plan

Green power market

(Paragraph re green power market assumptions)

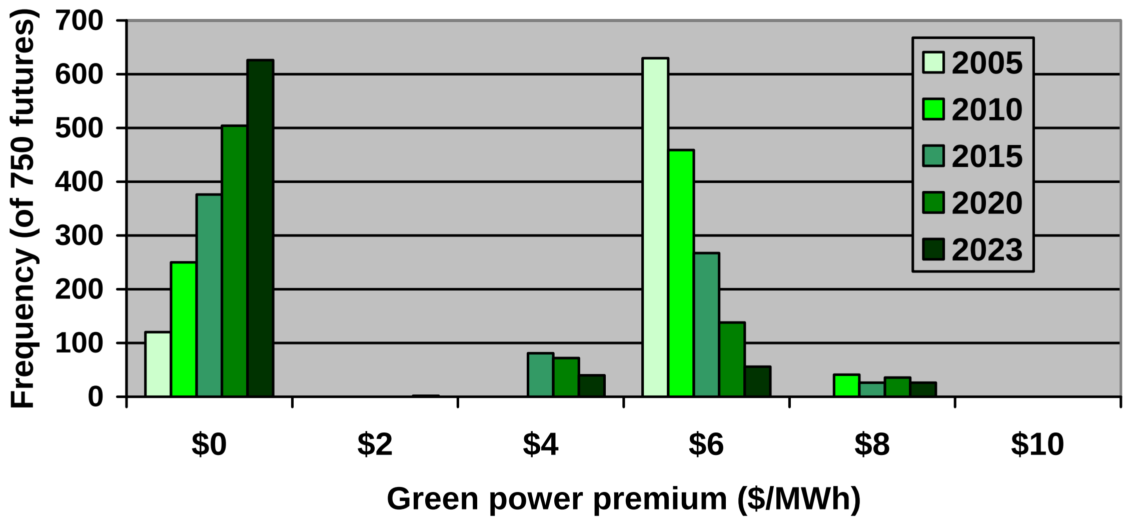

Figure 9-3: Green power market premium over the 20-year plan

Findings

The principal findings of the portfolio risk analysis and other assessments regarding generating resources are the following:

No apparent need for major generating resource development before 2010

The Council has concluded that unless there is an unanticipated and significant loss of existing generation, there is no apparent need on a regionwide basis for large-scale development of new generating capacity through the remainder of this decade. Two factors drive this conclusion. One is the significant surplus of generating capacity currently enjoyed by the region. This surplus is to a large extent a relic of the power price excursions of 2000 and 2001. High prices lead to both a substantial loss of regional load and construction of over 4200 megawatts of new regional generating capacity. The effects of lost load persist - energy loads have not recovered to 1999 levels. Much new capacity remains underutilized, especially independently owned gas-fired combined-cycle projects. Even at forecast medium-high rates of load growth, the current resource inventory appears sufficient to maintain a regional load-resource balance of -1500 average megawatts, or less, through 2011, the amount needed to maintain system reliability (Figure 9-4)[9]

[9] The Northwest can maintain reliability at a regional deficit of 1500 – 2000 aMW, assuming adequate import capability.

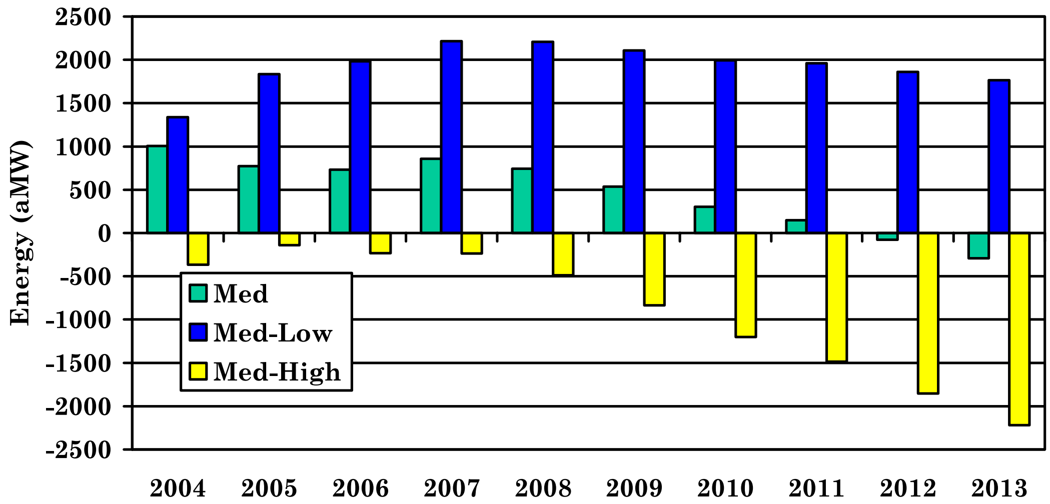

Figure 9-4: Regional load-resource balance

The second factor is the abundance of cost-effective conservation available for development. Not only is a substantial quantity of low-cost conservation available for development, but this conservation is free of natural gas price risk and the cost risk of possible carbon dioxide control measures. Aggressive acquisition of the conservation resource provides a lower risk, lower cost regional resource mix than alternatives containing large new generating resources of any kind.

(Paragraph re assumed retirements)

Some individual generating projects may become available and cost-effective prior to 2010

Opportunities for development of specific cost-effective renewable energy and combined heat and power projects are likely to surface prior to 2010. Examples might include landfill, animal waste or wastewater treatment plant energy recovery, hydropower renovations, forest residue energy recovery, remote photovoltaics and industrial or commercial combined heat and power projects. The opportunity to economically develop these projects is often created by needs not directly related to electric power production, such as a waste disposal problem, process or equipment upgrading or new commercial and industrial development. These opportunities should be monitored and secured if cost-effective as they arise.

Because of the diversity of potential projects, these types of resources were not included in the portfolio risk analysis. Several examples of these types projects are described in Chapter 3 and their costs compared to forecast electricity prices. That comparison suggests that there will likely be cases for which these types of projects will be cost-effective. For cogeneration projects, factors leading to superior cost-effectiveness in comparison to the generic resources considered in the portfolio risk studies include higher thermal efficiency, supplementary revenue streams and avoided transmission and distribution costs. Higher thermal efficiency reduces the exposure of these projects to fuel price and carbon dioxide risk. Likewise biomass, small hydropower, geothermal and other renewable resources not considered in the portfolio risk analysis offer the fuel and carbon dioxide risk reduction qualities of wind and in addition produce higher-quality (non-intermittent) power and in the case of projects using biomass residues, may benefit from offset waste disposal costs.

During the preparation of this plan, the Council has become aware of the need to improve the ability to identify, evaluate and develop cost-effective CHP and small-scale renewable resources. These issues include:

- Lack of routine processes for identifying potentially cost-effective customer-side CHP and small-scale renewable energy resources.

- Lack of commonly accepted resource cost-effectiveness criteria that accurately reflect all significant costs and benefits of acquiring the resource. This includes the energy value, possible value of capacity and other ancillary services, offset transmission and distribution costs and losses and environmental effects.

- Disincentives to utility acquisition of power from projects owned or operated by others. The inability for an investor-owned utility to receive a return on risk or for use of funds associated with power purchase agreements or investment in generation owned or operated by others generation may create an economic disincentive for securing these resources.

- Lack of uniform interconnection agreements and technical standards. Standard agreements should be transparent, free of unnecessary complexity and expeditiously processed. Standby tariffs should accurately and equitably reflect the costs and benefits of customer-side generation.

- Impediments to the sale of excess customer-generated power

Gas combined-cycle and wind are most attractive resources when new bulk power supplies needed

The portfolio risk analysis indicates that when needed, the most attractive new generating resources will be a mix of wind power and natural gas combined-cycle plants. The attractiveness of windpower appears to be the result of forecast cost reduction, absence of fuel price risk and immunity to climate change policy risk. The preferred plan would involve being prepared to begin construction of up to XXXX MW of new wind power capacity by 20__ (Figure 9-4). On average, over the futures examined YYYY megawatts of windpower are developed by 20__.

Sensitivity analyses on assumed windpower cost reduction, natural gas prices and carbon dioxide control costs did not significantly affect these conclusions?? (Discuss when complete)

The attractiveness of natural gas combined-cycle plants in this period of high gas prices appears somewhat contrary to recent conventional wisdom. The attractiveness of combined-cycle plants appears to be the result of forecast cost reductions and performance improvements partly offsetting fuel price risks and the lower sensitivity to climate change policy risk than coal-fired power plants. The preferred plan would involve being prepared to begin construction of up ZZZZ MW of new combined-cycle capacity by 20__ (Figure 9-4). On average, over the futures examined WWWW megawatts of windpower are developed by 20__.

Sensitivity analyses on assumed natural gas prices and carbon dioxide control costs did not significantly affect these conclusions?? (Discuss when complete)

Maintain inventory of sites and partly completed plants ++++

Uncertainties regarding large-scale windpower development need to be resolved

The portfolio risk analysis suggests the large-scale development of windpower will provide significant cost and risk reduction benefits. For wind to provide these benefits requires a large high quality developable resource, continued wind plant cost reduction and wind turbine technology improvements, relatively low shaping and firming costs, the ability to expeditiously extend transmission service to promising wind resource areas and a robust wind development infrastructure. The Council has included large quantities of wind in the plan despite uncertainties associated with these assumptions because of the benefits wind can provide to the regional power system. Because large-scale development of new resources is not required before the end of the decade, adequate time is available to resolve these uncertainties.

The most effective approach to resolving uncertainties associated with large-scale deployment of wind generation appears to be the development of a series of commercial-scale pilot wind power projects at a diverse set of wind resource areas. These projects would provide the means to (1) confirm the development potential of several wind resource areas including wind resource assessment, assessment of environmental issues and planning for transmission and other infrastructure requirements; (2) monitor wind power cost and performance trends; (3) assess the cost of firming and shaping large amounts of windpower, including the possible benefits of geographic diversity; (4) improve understanding of the capacity value of wind; (5) secure the necessary environmental assessments and permits for development of the ultimate potential of a wind resource area and (6) strengthen regional wind development infrastructure.

Development of commercial-scale pilot projects is not necessarily the least expensive approach to resolving these uncertainties. In theory, many of these objectives could be achieved by lower cost research and development activities, as advocated in the Council's 1991 plan. In practice, resolution of wind power uncertainties through research and development projects proved difficult, a situation made even more difficult with the subsequent evolution of greater competition in the utility industry and a largely independent windpower sector that has persisted even with retrenchment of industry restructuring.

The cost of developing of a series of commercial-scale projects in advance of need was tested using the portfolio risk model. The objective of this test was not to explore the benefits of sustained development in resolving uncertainties, which would be rather difficult to quantify, but rather to understand the cost implications. Sustained annual development of **XXX** megawatts, on average was found to ... **(cost & risk effects when sensitivity analysis available)**

Other promising bulk power alternatives may become available

Other promising bulk power options (discuss)

Coal gasification
Oil sands CHP
CO2 sequestration

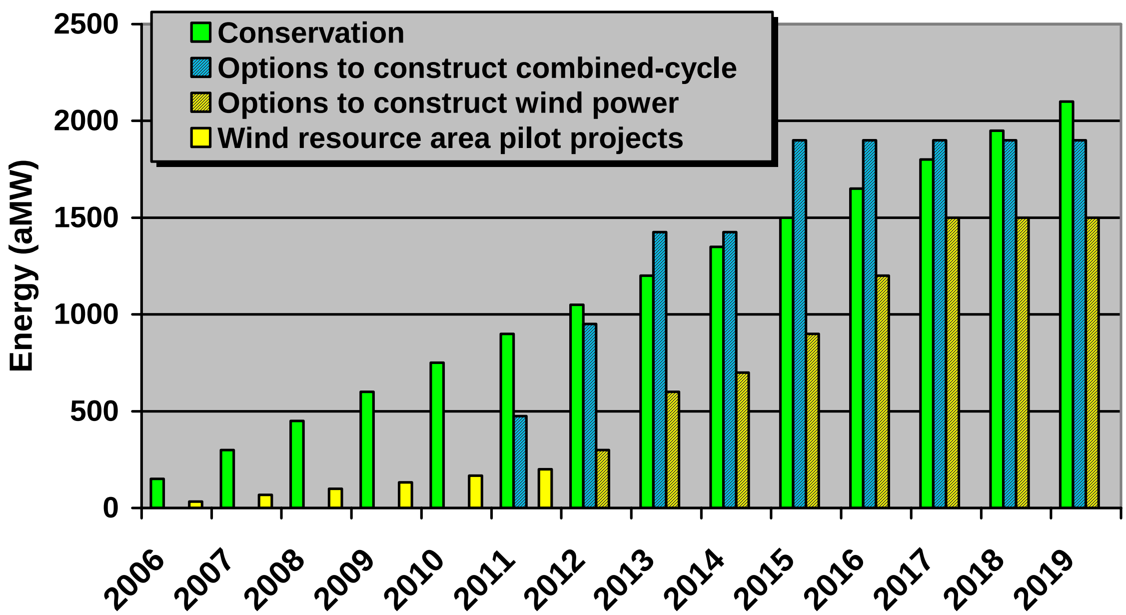

Figure 9-5: Recommended resource development schedule

Individual utility needs may differ

Though no large-scale generating resource development appears to be needed at the regional level, the circumstances of individual utilities may be such that the near-term development or acquisition of new generating resources may be desirable or necessary. Some utilities may be in resource deficit, having experienced more rapid load growth than the regional average or having not have lost load to the extent of the regional average. The conservation potential available to some utilities may be insufficient to meet near-term loads. A utility may have been purchasing a major portion of supply on short-term contract, and may find it desirable to increase the amount of generation owned or on long-term contract. Some of the recent Request for Proposals for generation may be attempts to secure such supplies at the lowest cost. Finally, some utilities may be encountering peak period capacity needs that cannot be dealt with through demand response. Any of these situations may result in a specific utility needing to acquire generating resources before regionwide needs are present.

Likewise, the preferences cited here for wind power and gas-fired combined-cycle plant are based on the overall regional situation and may not be suitable for all utilities. A utility may already have a large amount of gas-fired capacity, for example and it would be unwise to extend natural gas price risk by acquisition of additional gas-fired supply. Climate change risk, though very important in arriving at the recommendations of this plan, is very uncertain, and a utility may have a different view of the magnitude or timing of climate change risk, leading to different valuation of resource qualities. Finally, because of its geographical, transmission or service territory situation, an individual utility may have different resource choices than considered here, or the cost of resources may differ from the assumptions used here. For any of these reasons, the resource choices of individual utilities may differ from the recommendations of this plan. However, whatever the timing and nature of resource choice, resource decisions should be made using the best available information and analytical tools.