FORTISBC

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May 29, 2009

Ms. Erica M. Hamilton
Commission Secretary
BC Utilities Commission
Sixth Floor, 900 Howe Street, Box 250
Vancouver, BC V6Z 2N3

Dear Ms. Hamilton:

Re: FortisBC Inc. 2009 Resource Plan

FortisBC Inc. ("FortisBC" or the "Company') submits its long term Resource Plan for the period 2009 - 2028 (the "2009 Resource Plan"), and seeks an order by the Commission pursuant to Section 44.1(6)(a) of the Utilities Commission Act (the "Act) that the Commission accepts the 2009 Resource Plan (including, without limitation, the Company's preferred resource portfolio described in Section 8 of the 2009 Resource Plan), and determines that carrying out the 2009 Resource Plan would be in the public interest. The Company also seeks an order by the Commission pursuant to Section 44.2(3)(a) of the Act that the Commission accepts the schedule of proposed expenditures described in Section 9 of the 2009 Resource Plan and determines that making the expenditures would be in the public interest.

With regard to regulatory process, FortisBC requests that the Commission refrain from setting a regulatory timetable for the disposition of this Application at this time. FortisBC and British Columbia Hydro and Power Authority ("BC Hydro") are currently engaged in negotiations to renew the long-term power purchase agreement between them (the "BC Hydro PPA"), the current term of which expires on September 30, 2013. The disposition of

this Application relating to the Company's 2009 Resource Plan is, in part, dependent on the prior resolution of the terms on which the BC Hydro PPA will be renewed. As stated in Section 3.3.2 of the 2009 Resource Plan, FortisBC intends to file no later than 30 days hence, a report which will include:

(a) a summary of the status, as at the date of the report, of negotiations for the renewal of the BC Hydro PPA; and

(b) a request for:

  (i) approval of a form of renewed BC Hydro PPA agreed to by BC Hydro and FortisBC;

  (ii) fixing of a timetable that would allow the parties to complete their negotiations; or

  (ii) disposition by the Commission of any issues at that time unresolved and outstanding between BC Hydro and FortisBC in relation to the proposed renewal of the BC Hydro PPA.

The report to be filed at that time will also contain FortisBC's recommendations regarding process and timetable for disposition by the Commission of this Application.

If further information is required, please contact the undersigned at (250) 717 0890.

Sincerely,

Dennis Swanson
Director, Regulatory Affairs

FORTISBC

2009 Resource Plan

May 29, 2009

1 EXECUTIVE SUMMARY

FortisBC Inc. (the "**Company**" or "**FortisBC**") is an integrated regulated electric utility that generates, transmits and distributes electricity to customers in the southern interior of British Columbia. The Company serves over 157,000 customers directly and indirectly, focusing on the delivery of safe, reliable and cost effective electricity. FortisBC's customer base represents approximately 8% of British Columbia's electric utility customer total[1] and accounts for about 6%[2] of total provincial domestic sales.

The purpose of this 2009 Resource Plan is to guide FortisBC over the 20-year period from 2009 to 2028 in its acquisition and management of new generation resources to supplement the Company's current resource base.

This 2009 Resource Plan researches and analyzes the context (including regulatory, commercial and operational) within which FortisBC operates, its load and peak demand forecasts, its current resource capabilities and the potential generation resource options available to it to meet forecast needs during the 20-year planning period of this 2009 Resource Plan, all with a view to assisting the Company to achieve its goals of:

1. moving towards self-sufficiency through the acquisition of firm-capacity generation resources sufficient to ensure long-term, reliable power for FortisBC's customers;

2. mitigating the uncertainty and risks inherent in the Company's current market purchase strategy; and

3. balancing cost effectiveness with the BC Energy Plan's directions and Policy Actions.

This 2009 Resource Plan satisfies the applicable requirements of Section 44.1 of the Act and is in the interests of FortisBC's customers. The P3-HYBRID resource portfolio described in Section 8 of this 2009 Resource Plan as the Company's preferred resource strategy satisfies the applicable requirements of Section 64.01 of the Act.

FortisBC has prepared and is filing this 2009 Resource Plan with the British Columbia Utilities Commission (the "**Commission**") in accordance with the applicable requirements of the *Utilities Commission Act*, R.S.B.C. 1996 c.473, as amended (the "**Act**"), and in accordance with the Commission's "Resource Planning Guidelines".

[1] FortisBC / (BC Hydro + FortisBC) customers. BC Hydro customer count is from its 2008 Annual Report.

[2] FortisBC / (BC Hydro + FortisBC) domestic sales. BC Hydro sales information is from its 2008 Annual Report.

1.1 BC Energy Plan

FortisBC has had regard to the Government of British Columbia's BC Energy Plan[3] in its preparation of this 2009 Resource Plan. Table 3.5.2.1 below lists those Policy Actions set out in the BC Energy Plan which FortisBC believes have direct impact on the Company's resource planning process. Further details are set out in Section 3.5.2.

Table 3.5.2.1: BC Energy Plan Policies

Target Area	BC Energy Plan Policy Action
Energy Conservation and Efficiency	1. Set an ambitious conservation target, to acquire 50 per cent of BC Hydro's incremental resource needs through conservation by 2020. **(Policy Action 1)** 2. Ensure a coordinated approach to conservation and efficiency is actively pursued in British Columbia. **(Policy Action 2)** 3. Encourage utilities to pursue cost effective and competitive demand side management opportunities. **(Policy Action 3)** 4. Explore with BC utilities new rate structures that encourage energy efficiency and conservation. **(Policy Action 4)**
Energy Security	1. Ensure self-sufficiency to meet electricity needs, including "insurance". **(Policy Action 10)**
Environment	1. All new electricity generation projects will have zero net greenhouse gas emissions. **(Policy Action 18)** 2. Zero net greenhouse gas emissions from existing thermal generation power plants by 2016. **(Policy Action 19)** 3. Require zero greenhouse gas emissions from any coal thermal electricity facilities. **(Policy Action 20)** 4. Ensure clean or renewable electricity generation continues to account for at least 90 per cent of total generation. **(Policy Action 21)** 5. No nuclear power. **(Policy Action 23)**

1.2 Capacity and Supply / Demand Gaps

FortisBC owns four hydroelectric generating plants on the Kootenay River (the "**FortisBC Plants**"). The Company is also party to a long term power purchase agreement with each of British Columbia Hydro and Power Authority ("**BC Hydro**") and Brilliant Power Corporation. The FortisBC Plants and the power purchase agreements with BC Hydro and Brilliant Power Corporation together constitute the bulk of the Company's existing power supply resources, providing a total winter peak capacity of approximately 551 MW. In 2008 these resources served about 74% of FortisBC's December 2008 winter peak of 746 MW, resulting in a shortfall of 195 MW which was met through short term, market based contracts. In 2009,

[3] "The B.C. Energy Plan: A vision for clean energy leadership", published by the Government of British Columbia on February 27, 2007

FortisBC's load forecast predicts a capacity shortfall of about 145 MW. The peak capacity shortfall grows to approximately 239 MW in 2028 based on expected loads. Further, as described in Section 5.3, a peaking capacity shortfall is forecast for six months of the year in 2009, eight months of the year by 2013 and ten months of the year by 2026.

The energy shortfall associated with the peak capacity gap – currently at about 18 GWh of annual requirements – will grow to approximately 131 GWh by 2028 net of demand side management ("**DSM**") savings.

1.3 Demand Side Management

The Company has implemented plans to accelerate realization of energy savings from existing DSM programs, to expand energy savings program offerings, and to investigate and offer appropriate and effective Demand Reduction programs with the objective of achieving the target set out in Policy Action 1 of the BC Energy Plan (relating expressly to BC Hydro) of meeting 50% of incremental resource needs through DSM measures by 2020 (the "**Energy Plan DSM Target**"). Meeting the Energy Plan DSM Target will require FortisBC to reduce by 50% the 553 GWh/year increase that FortisBC forecasts will have occurred by 2020. (It should be noted that this forecast is inclusive of existing levels of DSM activity). FortisBC's target, in the context of the Energy Plan DSM Target is, therefore, to achieve 277 GWh/year of additional, cumulative DSM savings by 2020.

FortisBC expects to achieve this target without taking into account energy savings that may be attributed to government-mandated codes and standards, price elasticity response, rate design impacts or energy savings incidental to Demand Reduction measures.

FortisBC is a capacity constrained utility. Accordingly, this 2009 Resource Plan is to a large measure focused on meeting FortisBC's forecast capacity shortfalls. Although the DSM activities that have been described in this 2009 Resource Plan are largely energy-focused, there are nevertheless associated capacity reductions resulting from proposed DSM activities. In this 2009 Resource Plan, FortisBC has applied these Demand Reductions as the first resource solution, and the Company's preferred resource strategy described in Section 8 of this 2009 Resource Plan provides the balance of the required solution.

1.4 Market Reliance

FortisBC relies on the wholesale electricity market to meet an increasing proportion of its capacity and energy requirements. The Company feels its strategy of making market purchases to close the gap between its supply and demand has generally been successful. Nevertheless, in its 2005 Resource Plan the Company stated its intention to conduct a study of the wholesale electricity market in the Western Electricity Coordinating Council ("**WECC**") region (in which the FortisBC service territory is

located) in order to assess the continuing viability of its market purchase strategy. In the Action Plan set out in FortisBC's 2005 Resource Plan, therefore, the Company undertook to complete such a study.

The Company engaged Willis Energy Services Ltd. to complete a wholesale electricity market analysis. That analysis (the "**Willis Market Analysis**") was completed in August 2007. Section 4 of this 2009 Resource Plan summarizes the results of the Willis Market Analysis, and a complete copy of the Willis Market Analysis is contained in Appendix E.

WECC's 2008 Power Supply Assessment (the "**2008 WECC PSA**") is an assessment of generation resource capacity in the WECC region, with projections to 2017. The 2008 WECC PSA also includes an assessment of generation resource capacity margins for the various WECC sub-regions.

Specific to the "Canada" sub-region summer capacity is expected to be sufficient until 2015, at which time current and currently planned resources will no longer provide sufficient capacity. The shortfall at that time is projected to be about 336 MW. Winter capacity in Canada is expected to be in deficit in 2009. By 2017, it is forecast that Canadian winter capacity will be in deficit by about 4,550 MW.

The 2008 WECC PSA includes the following caveats[4]:

Transmission Constraints:

- "This assessment is based on the physical ability of the interconnection to supply all loads regardless of contractual obligations. This means that the model uses economic relationships to calculate transfers between zones within the assigned limits. In reality, the ideal solutions may be difficult to duplicate in the operational environment. System operation for contract obligations and other conditions could adversely affect the availability of resources, and could impact the amount and timing of power supply deficiencies in specific zones".

Capacity Constraints:

- "Surplus generation in the Pacific Northwest zone was often stranded due to transmission limitations... However, neither the summer nor the winter analysis for the Northwest sub-region captures the limitations on the ability of the hydro system to sustain output levels beyond a single hour. Because of this limitation, the reported surpluses, both for Northwest sub-region's load and for potential export to other sub-regions of the West, may be unrealistically high."

Section 3.7 of this 2009 Resource Plan examines the market supply / demand forecast within the WECC region, and Section 4 provides further analysis.

[4] WECC 2008 Power Supply Assessment (Appendix D-2) page 50

FortisBC acknowledges that the market environment has changed substantially since the publication of the 2008 WECC PSA . Specifically, FortisBC understands that the short term forecast gap between regional loads and resources has been reduced. The May 2009 forecast of the Energy Information Administration (US Department of Energy)[5] notes that although energy consumption is expected to be reduced in 2009, it is expected to return to a more normal growth rate in 2010. Given that the planning period of this 2009 Resource Plan is twenty years, and that it contemplates new resources that require extended implementation timeframes, FortisBC believes it is still prudent to continue to use WECC's long term assessment of the wholesale electricity market. On this basis, over the longer term, an overall tight supply is forecast in the WECC region.

As demonstrated in Section 4.1.1.1, electricity prices from the wholesale market are volatile. Since 2003 the Mid-Columbia Light Load Hour price per MWh has varied between $0 and $150+, while Heavy Load Hour price per MWh has swung between $0 and $400+.[6] Alberta Power Pool price volatility was even greater.

FortisBC's continued reliance upon the wholesale electricity market to meet current and future needs is not a prudent strategy. The market is volatile and the cost of purchases is expected to trend upward. Availability of capacity products, as well as transmission capability necessary to move the power to FortisBC's market, is in question. Finally, the Act requires each public utility, in its resource planning, to consider the government's goal that British Columbia be self-sufficient by 2016.

1.5 Planning Margin

WECC requires utilities in the WECC region to have positive Operating Reserve Margins (hourly margins) in place at all times. WECC recommends (but does not require) that utilities also plan for positive margins on a long-term basis (called "**Planning Margin**"). A Planning Margin protects against the possibility of loss of supply owing to unplanned generating unit outage, transmission outage or unexpectedly high loads.

FortisBC currently complies with WECC's hourly Operating Reserves requirements which provide for an immediate, short term power supply reserve. However, FortisBC does not currently incorporate a Planning Margin. The risk associated with the lack of a physical Planning Margin is two-fold. First, if a single generating unit or portion of the transmission system goes out of service, FortisBC must make potentially expensive market purchases for as long as required to source a replacement supply. Second, given that power supply requirement forecasts are based on "normal" weather patterns (as described in Section 5.3), if the service territory were to experience extremes of weather (extended hot or cold periods) beyond those contemplated by the forecast, there is potential for insufficient power

[5] Energy Information Administration *Short-Term Outlook*, May 12, 2009

[6] Light Load Hours are 0100-0600 and 2300-2400 hours. Heavy Load Hours are 0700-2200 hours.

supply (that is to say that the resources planned to meet the expected forecast may prove insufficient). Accordingly, FortisBC believes it consistent with good utility practice to consider as well the additional load implied by a Planning Margin.

The Company commissioned two studies, the first by Willis Energy Services Ltd. and the second by Manitoba Hydro's HVDC Research Center, to help analyze the situation. Both reports, completed in late 2007, are attached as Appendices H-1 and H-2, respectively.

As a result of reviewing standard utility practice and following review of the two Planning Margin studies that it had commissioned, FortisBC concludes that it is prudent and necessary to acquire and maintain a Planning Margin resource in excess of forecast / load gaps. Accounting for the nature of FortisBC's resource stack, the Company recommends the implementation of a Planning Margin requirement of 45 MW to 55 MW[7] (see Table 6.3) – which is the sum of FortisBC's single largest generating unit at the Brilliant hydro facility, plus 5% of load responsibility. The recommended Planning Margin range equates to approximately 9% of FortisBC's capacity.[8]

However, the Company recognizes that an immediate implementation of the recommended Planning Margin would create a significant rate impact. Therefore, the preferred resource strategy described in Section 8 envisions the gradual, phased-in acquisition of a market based planning margin initially which will be replaced by a physical Planning Margin, effective in 2019.

Section 6.3 provides further details.

1.6 Transmission

From a transmission planning perspective, FortisBC's service territory consists of two distinct regions: the Okanagan region and the West Kootenay region. The West Kootenay region can be considered as a "generation-surplus" region with no requirement for reliability or capacity driven reinforcement within the planning period of this 2009 Resource Plan. By contrast, the Okanagan region faces both reliability and capacity constraints within the planning period of this 2009 Resource Plan. In normal operations (all transmission elements in service) the Okanagan system is forecast to accommodate load growth until 2020. Prior to 2020, the Okanagan transmission system will no longer meet N-1 reliability when the combined Kelowna/Penticton area demand exceeds approximately 615 MW. This load level is currently forecast to be reached in about 2015. A localized N-1 capacity violation occurs in the Kelowna area in approximately 2011/2012 as a result of insufficient transformation capacity. Finally, an N-1 violation occurs in approximately 2016 as a result of insufficient transformation capacity at the Vaseux Lake Terminal Station. By 2020 new supply solutions will require new transmission infrastructure, and there are a number of potential solutions to this issue – as set out in Table 3.9.2.2.4 – with costs ranging from

[7] The Planning Margin requirement is a "range" that grows with projected load growth over the planning period.

[8] For comparison, BC Hydro's reserve Planning Margin is 14%.

$70 million to $500 million+. There are also reliability-related, and local area (Kelowna) load reinforcements required. These forecast reinforcements are summarized as follows:

Table 3.9.3: Transmission Timing/Cost Summary

Type	In-Service	Capital Cost ($2009)
Kelowna Transformer	2011	$8 million
150 MVar static var compensator (SVC)	2013	$35 million
Vaseux Transformer	2016	$8 million
New Supply	2020+	$70 million - $500 million+

While, due to the time required to place new generation resources, the Kelowna-area transformer cannot be avoided, Kelowna-area new generation resource would provide potential to defer or eliminate the installation of the Vaseux transformer and the SVC, in addition to its inherent contribution to a solution for new supply requirements.

FortisBC's Preferred Resource Strategy envisions locating power generation in the Company's North Okanagan service territory, thereby potentially avoiding the last three items on the Table 3.9.3 list: the SVC, the Vaseux transformer, and new supply infrastructure.

1.7 Stakeholder Consultation

FortisBC considered it important to try to determine its customers' priorities with respect to what type of resourcing strategy those customers might support. As one would expect, there are many and varied opinions on the subject and it is difficult to draw definitive conclusions. The different consultation techniques FortisBC employed included the following:

1. presentations to 15 local government bodies;
2. 3 workshops; and
3. a broadly based telephone survey.

Despite the expected varied reactions, the following themes were prevalent:

- conservation should be considered first;
- environmentally sound solutions are important;

- transmission impacts are of concern;
- incremental cost is a concern; and
- lessening dependence on external, especially United States markets is favoured.

Subsequent to filing, FortisBC intends to present this 2009 Resource Plan to interested customers through a series of open houses within its service territory. Notification of the open houses will be published in area newspapers and a stakeholder consultation report summarizing the meetings will be filed as part of the regulatory process.

FortisBC will continue to ensure that this 2009 Resource Plan reflects its customers' input.

The stakeholder consultation process is summarized in Section 3.7 and additional detail is provided in Appendix C.

1.8 Resource Portfolios

FortisBC developed four criteria for its assessment of resource options portfolios. Those criteria are:

1. Does the portfolio, after new resources are in place and after application of DSM, close the forecast capacity and energy gaps, and provide a Planning Margin?
2. Does the portfolio minimize environment impacts?
3. How well does the portfolio meet the relevant Policy Actions set out in the BC Energy Plan (see Table 3.5.2.1)?
4. Is the portfolio economical?

The Company examined the relative merits of three portfolios of resource options, as described below:

Resource Option Portfolio 1 ("P1 – BC MARKETS")

This portfolio assumes that FortisBC will satisfy its existing and forecast capacity and energy gaps, and its need for a Planning Margin, pursuant to new power purchase agreements entered into with British Columbia-based power suppliers. These suppliers could be any of BC Hydro, Columbia Power Corporation/Columbia Basin Trust, Teck and/or other Independent Power Producers. New generation resources may have to be built to supply FortisBC's requirements, and it is the Company's expectation that it would have to pay market prices for the capacity and energy so supplied. This portfolio of generation resources is modeled to mimic the operational characteristics of those resources that may have to be built to supply FortisBC's load.

Resource Option Portfolio 2 ("P2 – GAS")

This portfolio assumes that FortisBC will satisfy its existing and forecast capacity and energy gaps, and its need for a Planning Margin, through construction of a series of Simple Cycle Gas Turbine units, the sizes and timing-of-acquisition of which are determined by the growing size of the Company's forecast capacity gap.

Resource Option Portfolio 3 – ("P3 – HYBRID")

This portfolio assumes that FortisBC will satisfy its existing and forecast capacity and energy gaps, and its need for a Planning Margin, through construction of a combination of clean, renewable resources with a gas-fueled peaking resource. Small Hydro with Capacity and Pumped Storage Hydro facilities provide the peaking and storage capacity necessary to shape energy to meet FortisBC's requirements. Later in the planning period, a source of intermittent Clean energy (for modeling purposes, Wind) is added to the portfolio. A Simple Cycle Gas Turbine provides short term peaking capability pending the Pumped Storage Hydro's in-service date and then converts to a standby Planning Margin role.

The portfolios are listed below in Table 7.3.1. The complete portfolio review process is detailed in Section 7.3.

Table 7.3.1: Portfolio Summary

Portfolio	Description	Installed Capacity (MW)	Dependable Capacity (MW)	Firm Energy Generated (GWh/yr)	Project Life (yrs)	Capital Cost (C$2009 millions)
P1 - BC Markets	Could include any of BC Hydro, Teck, Columbia Power Corp, and/or other BC-based Independent Power Producers	334	326	N/A	N/A	N/A
	Avoidable Transmission:					
	- SVC, Kelowna in **2013**					$35
	- Vaseux Transformer in **2016**					$8
	Total:	**334**	**326**	**N/A**		**$43**
P2 - Gas	- 2 x 42 MW Simple Cycle Gas Turbines (SCGT), and 2x 103 MW SCGT in **2014**	290	272	Only as required	30	230
	- 1 x 42 MW SCGT in **2020**	42	38	Only as required	30	$44
	Total:	**332**	**310**	**N/A**		**$274**
P3 - Hybrid	- 2 x 42 MW SCGTs in **2014**	84	76	Only as required	30	$88
	- Small Hydro with Capacity in **2017**	40	37	154	40+	$149
	- Pumped Storage Hydro (PSH) in **2019**	200	200	Only as required	50+	$510
	- Clean (Wind) in **2021**	30	8	66	20	$62
	Total:	**354**	**321**	**220**		**$809**

Table 7.4.4.4 below sets out the cost elements that make up the total cost, on a net present value basis (at 8% in $2009), of the three portfolios. A detailed explanation of the cost elements shown in Table 7.4.4.4 can be found in Section 7.4.4.4.

Table 7.4.4.4: Portfolio Cost Summary

Portfolio Cost Elements (NPV @8% in $2009 millions)	A	B	C	D	E	F		
Portfolio	Cost for Market Purchases	Power Cost for New Resources	Surplus Energy Sales	Capital Related Cost	Planning Margin	Total	Average Annual Rate Impact	20 Year Cumulative Rate Impact
P1 - BC MARKETS	$7.6	$311.3	$0.0	$24.9	$12.8	**$356.6**	1.12%	24.65%
P2 - GAS	$7.5	$51.6	$0.0	$143.8	$9.0	**$211.9**	0.66%	13.54%
P3 - HYBRID	$7.8	$61.3	($31.8)	$272.7	$11.8	**$321.9**	1.18%	25.75%

Column A - cost of purchasing capacity and energy from the wholesale electricity market prior to new portfolio resources coming on-line.
Column B - represents the costs associated with power production, including variable O&M, fuel, and GHG-related costs. In P1 - BC MARKETS this includes both the cost of capacity and cost of energy, as discussed in Section 7.3.5.2.. For P3 - HYBRID this includes the refill costs associated with the PSH, as discussed in Section 7.3.1.
Column C - represents potential surplus sales revenues, based upon the forecast in Table 7.6.
Column D - represents all rate requirement capital-related costs associated with new capital investment.
Column E - represents the cost associated with the market-based interim Planning Margin product purchased prior to a portfolio having a physical Planning Margin in place.
Column F is the total of Columns A through E

Table 7.4.4.4 also includes the average annual and total 20 year cumulative rate impacts for all three portfolios.

The portfolios were compared via a Decision Matrix exercise (Section 7.4) – the objective of which was to assist in identifying the solution which optimally balanced all four criteria. Table 7.4.6 below shows the relative performance of the three portfolios.

Table 7.4.6: Portfolio Performance v. Selection Criteria

Criteria	Portfolio		
Possible Total 4 - 24. "4" is Best; "24" is Worst	**P1 - BC MARKETS**	**P2 - GAS**	**P3 - HYBRID**
A) Gap Closure + Planning Margin	**3.0**	**1.0**	**2.0**
B) Environment	**5.0**	**5.0**	**2.0**
C) BC Energy Plan	**1.0**	**2.0**	**1.0**
D) Economics	**4.0**	**1.0**	**2.0**
Total of A + B + C + D =	**13.0**	**9.0**	**7.0**

Decision Matrix Legend

First =	
Second =	
Last =	

Complete details on criteria, weightings and portfolio scores in the Decision Matrix can be found in Section 7.4.6.

1.9 Preferred Resource Strategy

The P3 – HYBRID portfolio is, in FortisBC's opinion, a balanced solution to the Company's forecast capacity and energy gaps. It represents the resource portfolio that, through implementation of a blend of available technologies, provides the best solution in terms of environmental protection, operating flexibility and long term generation capacity sustainability. **Consequently, the P3 – HYBRID is FortisBC's Preferred Resource Strategy**.

The P3 – HYBRID portfolio contemplates the acquisition of resources as follows:

- 2014 - 2 x 42 MW Simple Cycle Gas Turbines to provide peak capacity support and to provide transmission support to the North Okanagan region. When no longer needed in the peak capacity support role (after the Pumped Storage Hydro comes on line) these facilities would be placed on standby in the Planning Margin role while continuing to provide transmission support.

- 2017 - 40 MW Small Hydro with Capacity.

- 2019 - 200 MW Pumped Storage Hydro facility to take over the peaking role from the Simple Cycle Gas Turbines and allow for storage to support both customer-owned and other system intermittent renewables such as Wind.

- 2021 - 30 MW of Clean Resource. Such a resource might be Wind (which FortisBC has used for modeling purposes) but could include other forms of clean power.

The Pumped Storage Hydro facility would be a net user of energy, requiring approximately 1.3 GWh in refilling energy for every 1.0 GWh of energy production. As the Pumped Storage Hydro facility would produce energy during Heavy Load Hours to match FortisBC's peak demands, refilling would take place during non-peak Light Load Hours. The refill energy would come primarily from FortisBC's existing and new clean renewable resources during those Light Load Hours.

1.9.1 Preferred Resource Strategy Load / Resource Balance

Figures 8.2.3-A and 8.2.3-B below following provide graphical representations of the P3-HYBRID portfolio's ability to meet both energy and capacity growth for high, expected and low forecasts over the planning period of this 2009 Resource Plan.

Figure 8.2.3-A: Preferred Resource Strategy – Energy Load / Resource Balance

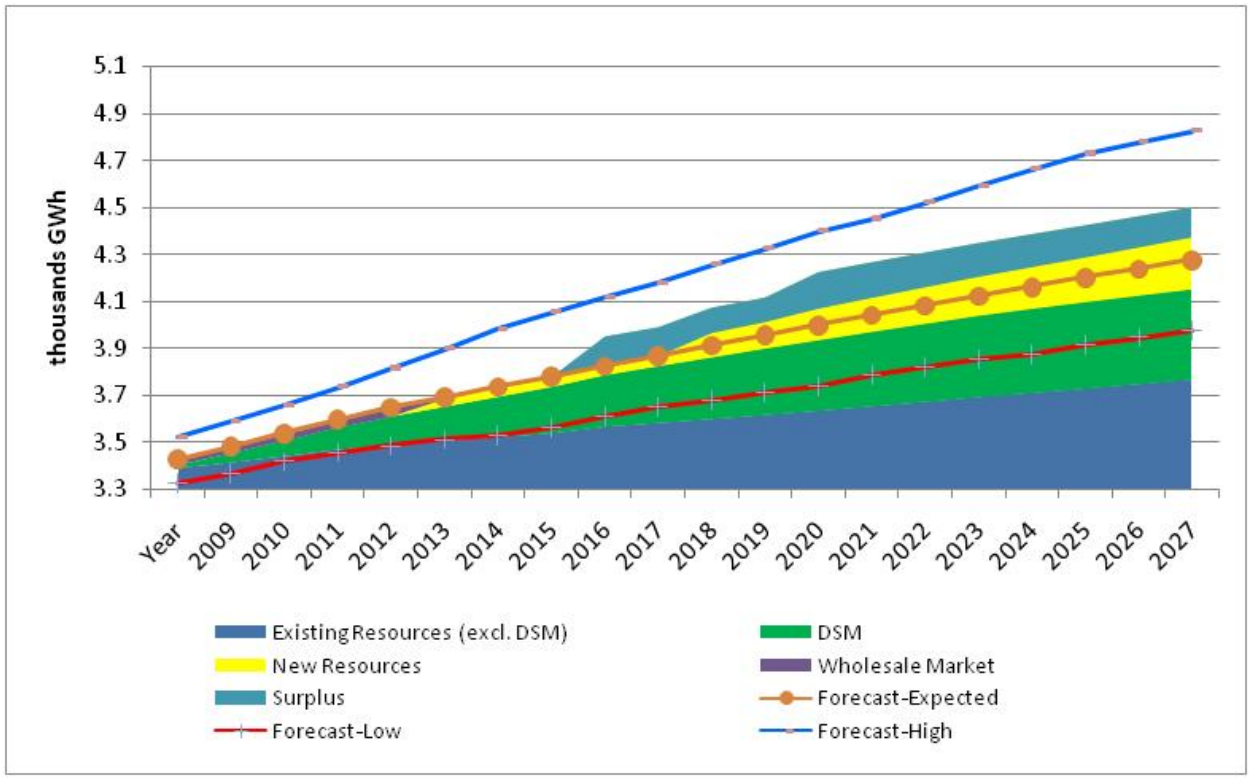
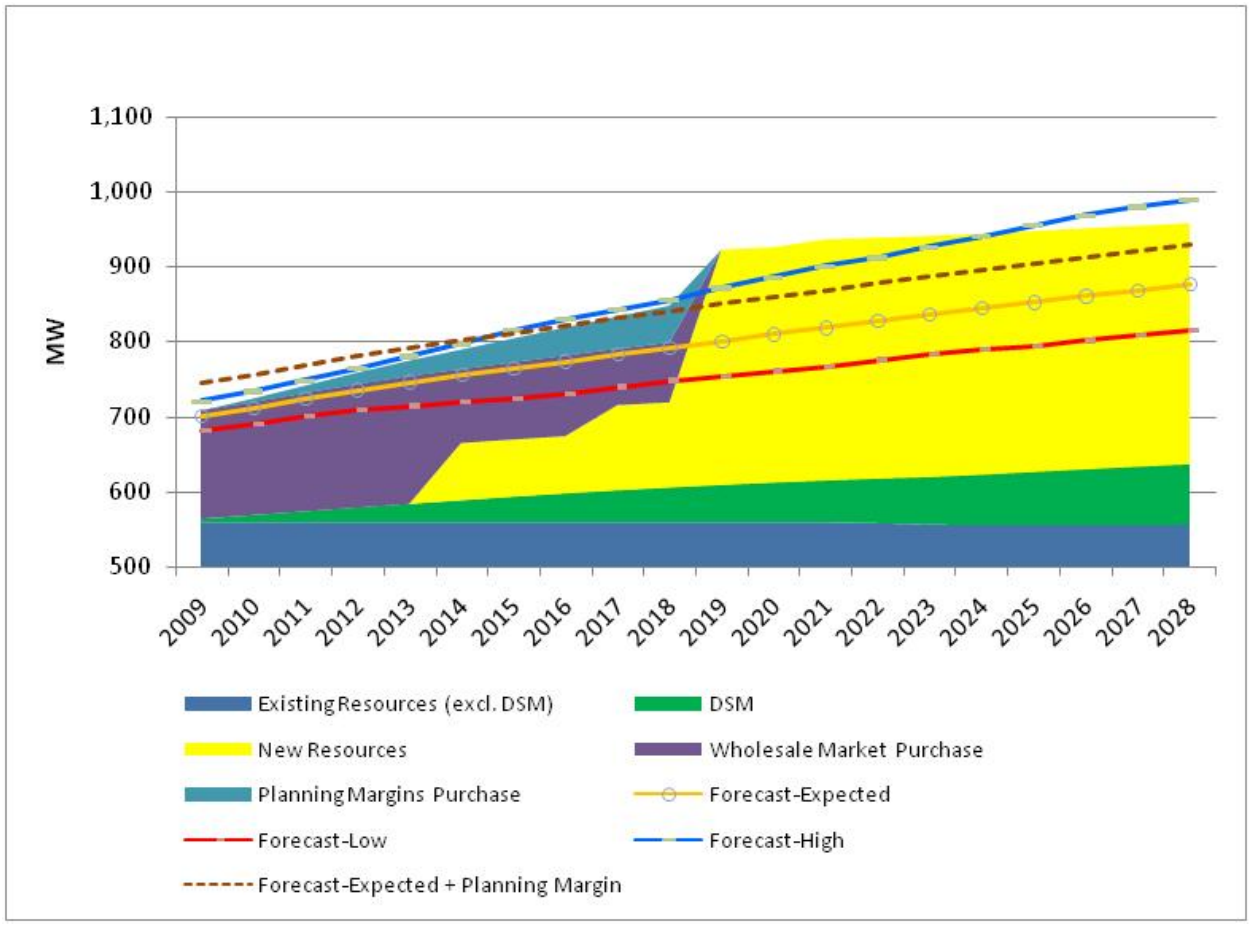


Figure 8.2.3-A above demonstrates that, after satisfying the forecast load, a portion of new resource energy goes to refill the Pumped Storage Hydro reservoir, with the balance becoming surplus.

Figure 8.2.3-B below demonstrates how the P3 - HYBRID portfolio deals with the capacity supply / demand gap over the planning period of this 2009 Resource Plan. The Low, Expected and High peak capacity forecasts are displayed by the red, orange, and blue lines, respectively. Until new resources start to come on line in 2014, the capacity supply / demand gap is covered by DSM and market purchases (green and purple areas). From 2014 until 2019, as new resources are introduced (the yellow area) the peak capacity gap is reduced and then finally eliminated. The blue area represents the market-based interim Planning Margin until it is replaced by conversion of the Simple Cycle Gas Turbines to the Planning Margin role in 2019. Finally, the brown dotted line represents the sum of the Expected peak capacity requirements, plus Planning Margin.

Figure 8.2.3-B: Preferred Resource Strategy – Capacity Load / Resource Balance



1.9.2 Transmission Considerations

FortisBC's ability to locate new generation in the Kelowna area is a key determinant of impacts associated with transmission infrastructure. The key to successful amelioration of potential transmission impacts (environmental and economic) is to defer or eliminate the need to construct transmission infrastructure. As discussed in Section 3.9 above, FortisBC has assumed that additional transmission infrastructure will be required to support the Okanagan load center. The P3 - HYBRID portfolio assumes that the Simple Cycle Gas Turbines will be located in the North Okanagan, although the viability of such a location needs to be the subject of further study. As a result the P3 - HYBRID portfolio may defer or eliminate the need to construct the additional transmission infrastructure necessary to move new generation to the Kelowna load – estimated to cost in the range $70 million to $500 million+.

1.9.3 Environmental Considerations

The P3 - HYBRID portfolio requires the construction of Simple Cycle Gas Turbines which will produce some greenhouse gas emissions. However, the emissions are limited, and by 2019, in normal

operations, would cease. Those emissions will be minimized by running the Simple Cycle Gas Turbines primarily as a peaking facility for the period 2014 to 2018 until the Pumped Storage Hydro facility takes over peaking operations. Peaking operations equate to less than 1% average effective capacity of the Simple Cycle Gas Turbines, with the peak year being 5.9% in 2016. From 2019 the Simple Cycle Gas Turbines are placed on standby in the Planning Margin role. Total greenhouse gas emissions will be approximately 115 thousand tonnes over the planning period of this 2009 Resource Plan – which equates to approximately 25% of the greenhouse gas emissions that would be produced by continuing to rely upon the wholesale electricity market. Running the Simple Cycle Gas Turbines in excess of peaking requirements could occur if electricity market economics indicate that surplus sales would benefit FortisBC's ratepayers. Run time in excess of planned peaking operations would produce additional greenhouse gas emissions at the rate of approximately ½ tonne per MWh.

FortisBC's environmental performance will be improved by the P3 – HYBRID portfolio's green resources of the Pumped Storage Hydro facility, Small Hydro, and Clean energy facilities when they come on line, and enhanced by the use of new and existing clean and renewable resources to provide the energy necessary to refill the Pumped Storage Hydro facility during Light Load Hours.

The storage and energy shaping capabilities provided by both the Small Hydro and Pumped Storage Hydro facilities would enable FortisBC to incorporate more intermittent clean resources to its system as required in the future. These attributes of the P3 – HYBRID portfolio's storage resources are necessary enablers for FortisBC's customers to pursue, on a larger scale, distributed generation sources such as backyard wind turbines, and rooftop solar systems. Further, these storage attributes could provide FortisBC with an opportunity to support clean and renewable resources outside the Company's service territory.

Therefore, when the entire portfolio is considered, the overall environmental benefits of the P3 – HYBRID portfolio are, in the Company's opinion, considered favourable.

1.9.4 BC Energy Plan

The P3 – HYBRID portfolio meets the objectives of all of the BC Energy Plan Policy Actions enumerated in Table 3.5.2.1 above, including Policy Action 20 (zero greenhouse gas emissions from coal), 18 (zero net greenhouse gas emissions) and 19 (zero net greenhouse gas emissions from existing thermal by 2016).[9] 100% of dependable capacity is from clean energy sources[10]. This meets the Policy Action 21 goal of 90%. Further, the P3 – HYBRID portfolio contributes to provincial self-sufficiency goals (Policy Action 10).

[9] FortisBC has included the costs of greenhouse gas – related offsets applicable to its planned operations of the Simple Cycle Gas Turbine in its economic analysis, as noted in Section 7.2.2.3

[10] Inclusive of existing power purchase agreements, and excluding the Planning Margin.

1.9.5 Capital Costs and Rate Requirements

1.9.5.1 Capital Expenditures

The capital expenditures for the PRS are noted in Table 8.6.1-A below:

Table 8.6.1-A: Preferred Resource Strategy Capital Expenditure

Preferred Resource Strategy	Year in Service	Capital Cost (C$2009 million)
Simple Cycle Gas Turbine (SCGT)	2014	$88.0
Small Hydro with Capacity	2017	$148.0
Pumped Storage Hydro (PSH)	2019	$510.0
Wind	2021	$63.0
Total		**$809.0**

1.9.5.2 NPV Calculations and Associated Rate Requirements

Table 8.6.2 below repeats the cost elements that make up the total cost, on a net present value basis (at 8% in $2009) of the Preferred Resource Strategy. Table 8.6.2 also includes the average annual and total 20 year cumulative rate impacts.

Table 8.6.2: Preferred Resource Strategy Net Present Value Cost Elements

	Portfolio Cost Elements (NPV @8% in $2009 millions)							
	A	B	C	D	E	F		
Portfolio	Cost for Market Purchases	Power Cost for New Resources	Surplus Energy Sales	Capital Related Cost	Planning Margin	**Total**	Average Annual Rate Impact	20 Year Cumulative Rate Impact
Preferred Resource Strategy	$7.8	$61.3	($31.8)	$272.7	$11.8	**$321.9**	1.18%	25.75%

Column A - cost of purchasing capacity and energy from the wholesale electricity market prior to new portfolio resources coming on-line.
Column B - represents the costs associated with power production, including variable O&M, fuel, and GHG-related costs. For the Preferred Resource Strategy this includes the refill costs associated with the PSH, as discussed in Section 7.3.1.
Column C - represents potential surplus sales revenues, based upon the forecast in Table 7.6.
Column D - represents all rate requirement capital-related costs associated with new capital investment.
Column E - represents the cost associated with the market-based interim Planning Margin product purchased prior to a portfolio having a physical Planning Margin in place.
Column F is the total of Columns A through E

The P3 – HYBRID portfolio will, (for the "expected" load, the net present value of Revenue Requirements @ 8% discount rate in 2009 dollars, over the planning period of this 2009 Resource Plan) cost approximately $322 million, including $12 million for the interim market-based Planning Margin, and approximately $32 million in surplus sales.

In order to manage and minimize both rate implications and reliability risk related to the Planning Margin, FortisBC has chosen to phase-in the acquisition of the market-based, interim Planning Margin pending the Simple Cycle Gas Turbines conversion to the Planning Margin role in 2019.

FortisBC has investigated the potential economic benefit of running the Simple Cycle Gas Turbines to take advantage of market opportunities. Even though there appear to be few predictable opportunities to engage in profitable off-system sales, the Company would be well positioned to take advantage of short term market excursions and this could generate economic benefits to offset the rate impact of the P3 – HYBRID portfolio. Of course, this would also require the acquisition of the required environmental offsets.

The Pumped Storage Hydro facility provides FortisBC with similar opportunities to take advantage of short term market price excursions to generate economic benefits to offset the rate impact of the P3 – HYBRID portfolio. Additionally, the storage attributes of the Pumped Storage Hydro facility are considered to have economic potential in the sale of related ancillary services to shape and firm otherwise intermittent power from other renewable resources. The as-yet-unformed market for these services could include both British Columbia as it continues to develop renewable sources of electricity and the United States as it seeks capacity to support its Renewable Portfolio Standards.

The rate impact for the P3 – HYBRID portfolio, without consideration for potential revenue streams as discussed above, equates to an annual average of 1.18%. The twenty year cumulative rate impact is 25.75%.

Full details of the preferred resource strategy can be found in Section 8.

1.10 Action Plan

To implement the Preferred Resource Strategy, FortisBC proposes the following Action Plan:

1. The Company will implement its preferred resource strategy, as outlined in Section 8, pursuant to the following:

    (a) FortisBC requests that the Commission accept this 2009 Resource Plan (including, without limitation, the P3 – HYBRID portfolio described in Section 8 of this 2009 Resource Plan as the Company's preferred resource strategy), and determine that carrying out this 2009 Resource Plan would be in the public interest, all pursuant to Section 44.1(6)(a) of the Act; and

    (b) FortisBC requests that the Commission accept the following schedule of proposed expenditures, and determine that making the expenditures would be in the public interest, all pursuant to Section 44.2(3)(a) of the Act:

(i) **Planning Margin:** expenditures of up to **$150,000 required in 2010**. These funds are for the preparation and implementation of an RFP process that will result in the identification of a preferred planning margin (capacity product) resource for which FortisBC will file with the Commission an application pursuant to Section 71 of the Act. The interim Planning Margin is required as a medium term, bridging resource until the acquisition of the Pumped Storage Hydro facility as noted below.

(ii) **Simple Cycle Gas Turbine:** expenditures of up to **$1.5 million required in 2010 and 2011**. These funds are to complete pre-CPCN work necessary to prepare and file a CPCN application in time to meet an in-service date of 2014. This pre-CPCN work will include (a) site evaluations and acquisition, (b) environmental assessment, and (c) pre-engineering cost assessment work. The pre-engineering cost assessment work will develop the detailed cost assessments required to identify the funds necessary to develop a CPCN application for a Simple Cycle Gas Turbine plant. The pre-engineering cost assessments, an update on the status of the environmental assessment, as well as a request for CPCN development funds will be filed with the Commission by the end of 2010. A full CPCN application will be filed in 2011.

(iii) **Small Hydro:** expenditures of up to **$500,000 required in 2010**. These funds are to complete the pre-CPCN work necessary to prepare and file a CPCN application in time to meet an in-service date of 2017. This work will include (a) site evaluations and acquisition, and (b) pre-engineering cost assessment work. The pre-engineering cost assessment work will develop the detailed cost assessments required to identify the funds necessary to develop a CPCN application for a Small Hydro with Capacity facility. The pre-engineering cost assessments, as well as a request for CPCN development and environmental assessment funds will be filed with the Commission by the end of 2010. A full CPCN application will be filed in 2012.

(iv) **Pumped Storage Hydro:** expenditures of up to **$500,000 required in 2010** are in the public interest. These funds are to complete the pre-CPCN work necessary to prepare and file a CPCN application in time to meet a proposed in-service date of 2019. The pre-CPCN work will include (a) site evaluations, selection and acquisition work, and (b) pre-engineering cost assessments. The pre-engineering cost assessment work will develop the detailed cost assessments required to identify the funds necessary to develop a CPCN application for a Pumped Storage Hydro facility. The pre-engineering cost

assessments, as well as a request for CPCN development and environmental assessment funds will be filed with the Commission by the end of 2010. A full CPCN application will be filed in 2012.

(v) **Clean:** expenditures of up to **$250,000 required in 2012**. These funds are required for the investigation of the potential for a new Clean Energy resource(s) suitable for FortisBC are in the public interest. It is anticipated that this investigation may take the form of a Clean Call for Power, however, further study is required. A report on this investigation, as well as timetable for development necessary to bring this resource into service by 2021 will be filed with the Commission in 2014.

2. In accordance with Section 44.1(2) of the Act, the Company proposes to update this Resource Plan in two years (that is, by 2011), or sooner, if circumstances materially change prior to that time or at such other time as the Commission requires.

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2 GLOSSARY

BC Clean Energy: Resources and technological applications that may qualify as a source for Clean or Renewable Electricity production may include: Biogas Energy, Biomass Energy, Energy Recovery Generation (ERG), Geothermal Energy, Hydrocarbon Energy, Hydro Energy, Hydrogen, Municipal Solid Waste (MSW), Solar Energy, Tidal Energy, Wave Energy, and Wind Energy, if they meet the definition of clean as prepared by the Ministry of Energy and Mines. This refers to energy technologies that result in a net environmental improvement relative to existing energy production.

BC Energy Plan: A statement of British Columbia government policy related to provincial energy matters issued by the Minister of Energy and Mines in February 2007.

Canal Plant Agreement (CPA) Entitlement: In return for predefined monthly amounts of power (the "entitlement"), FortisBC allows BC Hydro to divert water from the FortisBC generating stations to a BC Hydro owned generating station.

Capacity:
(1) The instantaneous power plant output at any given time, normally measured in kilowatts (kW) or megawatts (MW), of a power plant.
(2) The instantaneous system electricity demand at any given time, normally measured in kilowatts (kW) or megawatts (MW).
(3) A transmission facility's ability to transmit electricity, at any instant.
Related terms:

- **Maximum Capacity** - The highest generating plant output or transmission loading that can actually be achieved in situ.
- **Dependable Capacity** - The amount of megawatts a plant can reliably produce when required, assuming all units are in service. Factors external to the plant affect its dependable capacity. For example, streamflow conditions can restrict the dependable capacity of hydro plants and fuel supply constraints can impact thermal plant dependable capacity. Planned and forced outage rates are not included.
- **Installed Capacity** - (Also referred to as Nameplate Rating). The maximum rating of a generator or transmission station equipment identified by the manufacturer under specified conditions.

Capacity Purchase: The purchase of capacity without energy.

Certificate of Public Convenience and Necessity (CPCN): A certificate issued to a public utility by the British Columbia Utilities Commission for the construction or operation of a generating plant or other facility.

Columbia River Treaty: A treaty signed in 1961 between Canada and the United States of America that enabled storage reservoirs to be built and operated in British Columbia to regulate Columbia River flows to the United States for power production and flood control.

Demand Reduction: A Demand Side Management (DSM) action taken to reduce consumer electricity demand, in response to price, monetary incentives, or utility directives so as to maintain reliable electric service or avoid high electricity prices.

Demand-Side Management (DSM): Actions that modify customer demand for electricity, helping to defer the need for new utility energy and capacity supply additions.

Discount Rate: A rate used to determine the present value of receipts and/or expenditures that will occur over a period of time, reflecting the cost of capital.

Distributed Generation Resources: individual-use generation resources, such as solar or small wind turbines, distributed amongst and utilized by customers. Typically offsets individual customer power consumption and is hooked to the utility system via some form of net metering facility.

EIA: Energy Information Administration (US).

Energy: The electricity produced or used over a period of time, usually measured in kWh, MWh or GWh.

Entitlement Adjustment Agreement (EAA): An agreement related to the CPA that defines FortisBC entitlements. See also Canal Plant Agreement Entitlement.

Firm Market Purchase: The highest degree of reliable market power that can be purchased. It can only be curtailed due to the most severe contingencies such as the loss of the transmission path. See also Long-Term Firm Resource.

Gigawatt-Hour (GWh): One billion watt hours, one million kilowatt hours (an amount of electric energy that will serve about 100 residential customers for one year).

Green Energy: is a term describing what are thought to be environmentally friendly sources of power and energy. Typically, this refers to renewable and non-polluting energy sources. Green energy includes natural energetic processes that can be harnessed with little pollution. Anaerobic digestion, geothermal power, wind power, small-scale hydropower, solar power, biomass power, tidal power and wave power fall under such a category. Some versions may also include power derived from the incineration of waste.

Greenhouse Gases (GHG): Gases that are thought to contribute to global climate change, or the greenhouse effect, including carbon dioxide (CO2), carbon monoxide (CO) and methane (CH4).

Heavy Load Hours (HLH): The time of day in which peak demand occurs. Heavy Load Hours are from 0600h through 2200h, Monday to Saturday, excluding holidays.

Heat Rate: A measure of generating station thermal efficiency, computed by dividing the heat content of the fuel by the resulting net electric energy generated.

Heritage Contract: A 49,000 GWh per year contract (in perpetuity) between BC Hydro's Generation and Distribution Lines of Business to ensure BC Hydro customers (including FortisBC) benefit from the existing low-cost hydroelectric and thermal resources in the BC Hydro system.

Independent Power Producer (IPP): A privately owned electricity generating facility that produces electricity for sale to utilities or other customers.

Kilowatt (kW): One thousand watts, the commercial unit of measurement of electric power. A kilowatt is the flow of electricity required to light ten 100-watt light bulbs.

Kilowatt Hour (kWh): One thousand watts used for a period of one hour, the basic unit of measurement of electric energy. On average, residential customers in British Columbia use about 10,000 kWh per year.

Levelized Cost, Levelized Price: Levelizing is a method of converting a non-uniform stream of energy costs (or prices) into a present value equivalent uniform cost (or price).

Light Load Hours (LLH): All hours that are not Heavy Load Hours. See Heavy Load Hours.

Load: The amount of electricity required by a customer or group of customers.

Load Forecast: The expected load requirements that an electricity system will have to meet in the future.

Load Duration Curve: The variation in electrical load over time, usually hour-by-hour for a month or a year. The curve is sorted with the highest load over the period in question first followed by the next highest load and so on. This provides an effective way to determine how many hours loads exceeded a certain level.

Long-Term Firm Resource: A generation facility, Market Energy Block purchase or other power contract intended to meet load more than five years in advance. See also Firm Market Purchase.

Market: The network of electricity trading options that allows the purchase of wholesale electricity.

Market Volatility: Market prices vary considerably depending on the time of day, weather, fuel costs, and regional resource availability. This leads to potential market price shock risk.

Medium-Term Purchase: Energy Block market purchases made three to five years in advance.

Megawatt (MW): One million watts, one thousand kilowatts. A unit commonly used to measure both the capacity of generating stations and the rate at which energy can be delivered.

Megawatt Hour (MWh): 1,000 kWh.

Nominal Dollars: Amounts that have not been adjusted to remove the effect of changes in the purchasing power of the dollar.

Non-spinning Reserve: The non-spinning or supplemental reserve is the extra generating capacity that is not presently connected to the system but can be brought online after a short delay. This typically equates to the power available from fast-start generators, however could also include the power available on short notice by importing power from other systems or retracting power that is presently being exported to other systems.

Off-Peak: See Light Load Hours.

Operating Reserve: the operating reserve is the generating capacity available to the system operator within a short interval of time to meet demand in case a generator is lost or there is another disruption to the supply. Most power systems are designed so that, under normal conditions, the operating reserve is always at least the capacity of the largest generator plus a fraction of the peak load.

The operating reserve can be divided into two kinds of reserve power: the spinning reserve and the non-spinning or supplemental reserve:

Generators that intend to provide either spinning or non-spinning reserve should be able to reach their promised capacity within ten or so minutes.

Peaking Plant: A generation plant that typically only runs at times of peak demand. See also Super-Peaking.

Peaking Purchase: The purchase of energy that is required to meet load due to system capacity constraints during peak load days.

Planning Margin: Planning margin is the difference between the electricity supply capacity available and the capacity required to serve the load over a planning period. Intended to protect against a 1 day in 10 year loss of load possibility, the planning margin typically is between 10–30% over forecast load requirements, dependent upon the mix of generation resources employed.

Power: The instantaneous rate at which electrical energy is produced, transmitted or consumed, typically measured in watts (W), kilowatts (kW), or megawatts (MW). See also Capacity.

Pumped Storage Hydro: A Pumped Storage Hydro facility (PSH) is a method of storing and producing electricity to supply high peak demands by moving water between reservoirs at different elevations.

Present Value (PV): Today's discounted value of future receipts and/or expenditures. Often also called net present value. See also Discount Rate.

Real Dollars: In economics, the nominal values of something are its money values in different years. Real values adjust for differences in the price level in those years. Examples include a bundle of commodities, such as gross domestic product, and income. For a series of nominal values in successive years, different values could exist because of differences in the price level, an index of prices. But nominal values do not specify how much of the difference is from changes in the price level. Real values remove this ambiguity. Real values convert the nominal values as if prices were constant in each year of the series. For 2008 Real $, all nominal values are given in terms of 2008 prices.

Reliability: A measure of the adequacy and security of electric service. Adequacy refers to the existence of sufficient facilities in the system to satisfy the load demand and system operational constraints. Security refers to the system's ability to respond to transient disturbances in the system.

Resource: A source of electricity that is available to help meet or reduce electricity demand, including generation, purchases,

demand-side management and transmission facilities.

Short-Term Purchase: Energy Block market purchases made several months, up to a year, in advance.

Spinning Reserve: the extra generating capacity that is available by increasing the power output of generators that are already connected to the power system.

Spot Market: Real-time (hourly) and day-ahead market purchases and sales of electricity.

Super-Peaking Purchase: Electricity required to meet Load during peak usage periods. Generally considered to be approximately four to six hours out of the standard HLH block.

Upgrade: An improvement to an existing facility, which generally results in an increased performance of the integrated system.

Watt: The basic unit of measurement of electric power, indicating the rate at which electric energy is generated or consumed. (1 watt=1 joule per second).

Watthour (Wh): An electrical energy unit of measure equal to one watt of power supplied to, or taken from, an electric circuit steadily for one hour.

3 INTRODUCTION, PURPOSE & CONTEXT

3.1 Introduction to FortisBC Inc.

FortisBC Inc. (the "**Company**" or "**FortisBC**") is an integrated regulated electric utility that generates, transmits and distributes electricity to customers in the southern interior of British Columbia. The Company serves over 157,000 customers directly and indirectly, focusing on the delivery of safe, reliable and cost effective electricity. FortisBC's customer base represents approximately 8% of British Columbia's electric utility customer total[11] and accounts for about 6%[12] of total provincial domestic sales.

In 2008 FortisBC had revenues of $221 million from sales of 3,087 GWh. FortisBC's 2008 peak capacity requirement was 746 MW in December 2008. FortisBC's system set a new summer peak requirement record of 569 MW in July 2007.

The Company owns four hydroelectric generating plants located on the Kootenay River between Nelson and Castlegar, British Columbia, with a combined installed capacity of 223 MW, and approximately 7,000 kilometers of transmission and distribution power lines.

3.2 Purpose of 2009 Resource Plan

The purpose of this 2009 Resource Plan is to guide FortisBC over the 20-year period from 2009 to 2028 in its acquisition and management of new generation resources to supplement the Company's current resource base.

This 2009 Resource Plan researches and analyzes the context (including regulatory, commercial and operational) within which FortisBC operates, its load and peak demand forecasts, its current resource capabilities and the potential generation resource options available to it to meet forecast needs during the 20-year planning period of this 2009 Resource Plan, all with a view to assisting the Company to achieve its goals of:

1. moving towards self-sufficiency through the acquisition of firm-capacity generation resources sufficient to ensure long-term, reliable power for FortisBC's customers;

2. mitigating the uncertainty and risks inherent in the Company's current market purchase strategy; and

3. balancing cost effectiveness with the BC Energy Plan's directions and Policy Actions.

[11] FortisBC / (BC Hydro + FortisBC) customers. BC Hydro customer count is from its 2008 Annual Report.

[12] FortisBC / (BC Hydro + FortisBC) domestic sales. BC Hydro sales information is from its 2008 Annual Report.

FortisBC has prepared and is filing this 2009 Resource Plan with the British Columbia Utilities Commission (the "**Commission**") in accordance with the applicable requirements of the *Utilities Commission Act*, R.S.B.C. 1996 c.473, as amended (the "**Act**"), and in accordance with the Commission's "Resource Planning Guidelines".

3.3 Order Sought and Process-related Matters

3.3.1 Order Sought

FortisBC requests that the Commission make an order that:

(a) the Commission accepts this 2009 Resource Plan (including, without limitation, the P3 – HYBRID resource portfolio described in Section 8 of this 2009 Resource Plan as the Company's preferred resource strategy), and determines that carrying out this 2009 Resource Plan would be in the public interest, all pursuant to Section 44.1(6)(a) of the Act; and

(b) the Commission accepts the schedule of proposed expenditures described in Section 9 of this 2009 Resource Plan, and determines that making the expenditures would be in the public interest, all pursuant to Section 44.2(3)(a) of the Act.

A copy of the Draft Order proposed by FortisBC is attached as Appendix A.

3.3.2 Process-related Matters

For the purposes of this 2009 Resource Plan, FortisBC has assumed that its long-term power purchase agreement with British Columbia Hydro and Power Authority ("**BC Hydro**") made as of October 1, 1993 (the "**BC Hydro PPA**"), the current term of which expires on September 30, 2013, will be renewed on the basis described in Section 6.1.2.2 below, for a term that will extend at least to the end of the planning period of this 2009 Resource Plan. As described in Section 6.1.2.2 below, FortisBC and BC Hydro are currently engaged in negotiations to renew the BC Hydro PPA. Those negotiations have not, to date, resulted in agreement on terms satisfactory to both parties. In fact, FortisBC is not encouraged by the most recent exchange of correspondence between the parties, and does not believe that any such agreement is imminent. Still, the disposition of this Application relating to the Company's 2009 Resource Plan is, in part, dependent on the prior resolution of the terms on which the BC Hydro PPA will be renewed. Therefore, FortisBC hereby requests that the Commission refrain from setting a regulatory timetable for the disposition of this Application until after FortisBC has filed with the Commission, by no later than 30 days after the date hereof, a report which will include at least the following:

(a) a summary of the status, as at the date of the report, of negotiations for the renewal of the BC Hydro PPA;

(b) a request for:

(i) approval of a form of renewed BC Hydro PPA agreed to by BC Hydro and FortisBC; or

(ii) fixing of a timetable that would allow the parties to complete their negotiations; or

(iii) disposition by the Commission of any issues at that time unresolved and outstanding between BC Hydro and FortisBC in relation to the proposed renewal of the BC Hydro PPA; and

(c) recommendations regarding process and timetable for disposition by the Commission of this Application.

3.4 Relevant Provisions of *Utilities Commission Act* (British Columbia)

3.4.1 Provisions Relevant to Resource Planning

In 2008 the Government of British Columbia amended the *Utilities Commission Act* (British Columbia) in several respects directly relevant to FortisBC's resource planning process.

3.4.2 Mandatory Contents of Resource Plan

The Act now requires public utilities to file with the Commission a long-term resource plan. Section 44.1 of the Act expressly enumerates the requisite contents of such a plan. They are as follows:

(a) an estimate of the demand for energy the public utility would expect to serve if the public utility does not take new demand-side measures during the period addressed by the plan;

(b) a plan of how the public utility intends to reduce the demand referred to in paragraph (a) by taking cost-effective demand-side measures;

(c) an estimate of the demand for energy that the public utility expects to serve after it has taken cost-effective demand-side measures;

(d) a description of the facilities that the public utility intends to construct or extend in order to serve the estimated demand referred to in paragraph (c);

(e) information regarding the energy purchases from other persons that the public utility intends to make in order to serve the estimated demand referred to in paragraph (c);

(f) an explanation of why the demand for energy to be served by the facilities referred to in paragraph (d) and the purchases referred to in paragraph (e) are not planned to be replaced by demand-side measures;

(g) any other information required by the Commission.[13]

3.4.3 Commission to Review Resource Plan in light of Government's Energy Objectives

The amended Act also requires the Commission, when reviewing any resource plan of a public utility, to consider the principles and objectives of the Government of British Columbia's energy policy in relation to (among other things) long-term planning. In this regard, section 44.1 (8) of the Act states that "in determining … whether to accept a long-term resource plan, the Commission must consider:

(a) the government's energy objectives;

(b) whether the plan is consistent with the requirements under sections 64.01 and 64.02, if applicable;

(c) whether the plan shows that the public utility intends to pursue adequate, cost-effective demand-side measures; and

(d) the interests of persons in British Columbia who receive or may receive service from the public utility."[14]

The "government's energy objectives" (referred to in paragraph (a) of Section 44.1 (8) quoted above) are defined in the Act as meaning the following objectives:

(a) to encourage public utilities to reduce greenhouse gas emissions;

(b) to encourage public utilities to take demand-side measures;

(c) to encourage public utilities to produce, generate and acquire electricity from clean or renewable sources;

(d) to encourage public utilities to develop adequate energy transmission infrastructure and capacity in the time required to serve persons who receive or may receive service from the public utility;

(e) to encourage public utilities to use innovative energy technologies

[13] Act, section 44.1(2)

[14] Act, section 44.1(8)

(i) that facilitate electricity self-sufficiency or the fulfillment of their long-term transmission requirements, or

(ii) that support energy conservation or efficiency or the use of clean or renewable sources of energy;

(f) to encourage public utilities to take prescribed actions in support of any other goals prescribed by regulation.[15]

In relation to paragraph (b) of section 44.1 (8) (quoted above), section 64.01 of the Act requires each "public utility, in planning for (a) the construction or extension of generation facilities, and (b) energy purchases, (to) consider the government's goal that British Columbia be electricity self-sufficient by the 2016 calendar year and maintain self-sufficiency after that year"[16].

In relation to paragraph (c) of section 44.1(8) (quoted above), the Commission must determine whether the long-term resource plan shows that the public utility intends to pursue adequate, cost-effective demand-side measures. The Act defines "demand-side measure" as meaning "a rate, measure, action or program undertaken (a) to conserve energy or promote energy efficiency, (b) to reduce the energy demand a public utility must serve, or (c) to shift the use of energy to periods of lower demand".[17]

3.4.4 2009 Resource Plan consistent with Act

FortisBC has prepared this 2009 Resource Plan with a view to satisfying the requirements of the Act (referred to in Sections 3.4.2 and 3.4.3 above) relating to long-term resource planning.

With specific regard to the list of mandatory contents stipulated by Section 44.1(2) of the Act:

(a) Section 6.1.4 below contains an estimate of the demand for energy that FortisBC would expect to serve if it were not to take the demand-side measures contemplated by this 2009 Resource Plan;

(b) Sections 6.1.4.4 to 6.1.4.9 contain a plan of how FortisBC intends to reduce the demand referred to in paragraph (a) by taking the demand-side measures contemplated by this 2009 Resource Plan;

(c) Sections 6.2 and 6.3 contain an estimate of the demand for energy that FortisBC expects to serve after it has taken the demand-side measures contemplated by this 2009 Resource Plan;

[15] Act, section 1, definition of "government's energy objectives"

[16] Act, section 64.01(2)

[17] Act, section 1, definition of "demand-side measure"

(d) Section 8 contains a description of the facilities that FortisBC intends to construct or extend in order to serve the estimated demand referred to in paragraph (c);

(e) Section 8 contains information regarding the energy purchases from other persons that FortisBC intends to make in order to serve the estimated demand referred to in paragraph (c); and

(f) Sections 6, 7 and 8 contain an explanation of why the demand for energy to be served by the facilities referred to in paragraph (d) and the purchases referred to in paragraph (e) are not planned to be replaced by demand-side measures.

With reference to Section 44.1(8) of the Act, FortisBC believes that this 2009 Resource Plan is responsive to the government's energy objectives in that it sets out the Company's proposed efforts:

(a) to reduce greenhouse gas emissions (see Sections 7.4.2 and 8.4);

(b) to take demand-side measures (see Section 6.1.4);

(c) to produce, generate and acquire electricity from clean or renewable sources (see Sections 7.4.2, 8.3 and 8.4);

(d) to develop adequate energy transmission infrastructure and capacity in the time required to serve its customers (see Sections 3.8, 3.9 and 8.3); and

(e) to use innovative energy technologies

(i) that facilitate electricity self-sufficiency or the fulfillment of their long-term transmission requirements, or

(ii) that support energy conservation or efficiency or the use of clean or renewable sources of energy

(see Sections 7.1 and 7.4).

With respect to Section 64.01 of the Act, FortisBC believes that this 2009 Resource Plan furthers the government's goal that British Columbia be electricity self-sufficient by the 2016 calendar year and maintain self-sufficiency after that year (see Section 7.4.3).

With respect to Section 44.1(8)(c) of the Act, FortisBC believes that FortisBC intends to pursue adequate, cost-effective demand-side measures (see Section 6.1.4).

With respect to Section 44.1(6) of the Act, FortisBC believes that this 2009 Resource Plan is in the public interest and, in particular, in the interest of FortisBC's customers.

3.5 Governmental Policy and Legislation Regarding Environment

Recent policy initiatives of government at both the federal and provincial levels in Canada, in relation to the environment, directly impact on FortisBC's resource planning process.

Also of direct relevance are certain regional collaborative policy initiatives of provincial and state governments on each side of the Canada-United States border.

Also of relevance, though not directly applicable to FortisBC, are various legislative and policy initiatives of the federal and certain state governments in the United States. Since the wholesale electricity market in the United States is of significant size, operates in close proximity to FortisBC's service territory and is a potential source of energy and capacity products for FortisBC, the Company believes it must be aware of, and responsive to, the changing United States regulatory construct governing that market.

All of these governmental initiatives are discussed in the following Sections 3.5.1 to 3.5.3.

3.5.1 *Canadian Federal Regulatory Framework*

3.5.1.1 Framework for Regulating Air Emissions

The Government of Canada's plan to combat climate change is currently embodied in a document entitled "A Regulatory Framework for Air Emissions" (the "**Framework**"). The Government of Canada issued the Framework on April 27, 2007 as part of its overall "Turning the Corner: an Action Plan to Reduce Greenhouse Gases and Air Pollution" regulatory framework for reducing greenhouse gas emissions. The Framework contemplates that greenhouse gas emission reduction regulations will cover facilities in various industrial segments, including plants producing electricity by combustion. For existing facilities the Framework contemplates an improvement in greenhouse gas emissions intensity of 6% each year from 2007 to 2010, yielding an initial required reduction of 18% from 2006 levels in 2010, the year the proposed regulations come into force. Every year thereafter a 2% continuous improvement in emissions intensity will be required. By 2015, therefore, a reduction in emissions intensity of 26% from 2006 levels must be met. The "Turning the Corner" regulatory framework envisions greenhouse gas emission reductions of 60 to 70% by 2050.

On March 10, 2008**,** the Government of Canada published further details of the "Turning the Corner" regulatory framework. This updated plan includes mandatory reductions for industry, along with additional new measures to address two of Canada's key emitting sectors: oil sands and electricity. The details of the plan include:

- establishing a market price for carbon;

- setting up a carbon emissions trading market, including a carbon offset system, to provide incentives for Canadians to reduce their greenhouse gas emissions;

- setting a target that will effectively require oil sands starting operations in 2012 to implement carbon capture and storage; and

- effectively banning the construction of new dirty coal plants starting in 2012.

The details of the plan specify how emissions targets will apply to each industry sector, how the offsets and trading systems will work and how credits will be provided to companies taking early action to reduce their emissions.

3.5.1.2 Renewable Power Incentives Set to Expire

The "ecoENERGY for Renewable Power" program is an incentive program offered by the Canadian federal government. It provides an incentive of one cent per kilowatt-hour[18] for up to 10 years to eligible low-impact, renewable electricity projects built between April 2007 and March 2011. The incentive aims to reduce the cost gap between new technologies and traditional sources of electricity. ecoENERGY for Renewable Power encourages production of clean electricity from renewable sources such as wind, biomass, low-impact hydro, geothermal, solar photovoltaic and ocean energy. Eligibility is limited to projects having a minimum size of 1 MW. Businesses, municipalities, institutions and organizations, electric utilities and independent power producers are eligible.

Since this program is currently set to expire in 2011 FortisBC has, for the purposes of this 2009 Resource Plan, excluded the incentive contribution from its costing when assessing the viability of renewable power resources.

3.5.2 British Columbia Regulatory Framework

3.5.2.1 BC Energy Plan

On February 27, 2007, the Government of British Columbia issued "The B.C. Energy Plan: A vision for clean energy leadership"[19] (the "**BC Energy Plan**"). The BC Energy Plan sets out proposed government action in British Columbia's energy sector, and a strategy for reducing greenhouse gas emissions and investment in alternative technology. The BC Energy Plan outlines conservation, energy efficiency and clean energy goals to make the province of British Columbia energy self-sufficient by 2016.

The BC Energy Plan acknowledges that British Columbia is currently dependent on other jurisdictions for up to 10% of its electricity supply and estimates that provincial demand for electricity will grow by up to

[18] Or $10.00 / MWh

[19] The BC Energy Plan is attached as Appendix B

45% over the next 20 years. Further, it contemplates that 50% of BC Hydro's projected load growth be supplied by demand-side management measures by 2020.

The BC Energy Plan contains detailed prescriptive "Policy Actions" that the government intends to take in the electricity sector. FortisBC has identified a number of those Policy Actions which it believes have direct impact on its resource planning process. Those Policy Actions are identified in Table 3.5.2.1 below.

Table 3.5.2.1: BC Energy Plan Policy Actions Impacting FortisBC Resource Plan

Target Area	BC Energy Plan Policy Action
Energy Conservation and Efficiency	1. Set an ambitious conservation target, to acquire 50 per cent of BC Hydro's incremental resource needs through conservation by 2020. **(Policy Action 1)** 2. Ensure a coordinated approach to conservation and efficiency is actively pursued in British Columbia. **(Policy Action 2)** 3. Encourage utilities to pursue cost effective and competitive demand side management opportunities. **(Policy Action 3)** 4. Explore with BC utilities new rate structures that encourage energy efficiency and conservation. **(Policy Action 4)**
Energy Security	1. Ensure self-sufficiency to meet electricity needs, including "insurance". **(Policy Action 10)**
Environment	1. All new electricity generation projects will have zero net greenhouse gas emissions. **(Policy Action 18)** 2. Zero net greenhouse gas emissions from existing thermal generation power plants by 2016. **(Policy Action 19)** 3. Require zero greenhouse gas emissions from any coal thermal electricity facilities. **(Policy Action 20)** 4. Ensure clean or renewable electricity generation continues to account for at least 90 per cent of total generation. **(Policy Action 21)** 5. No nuclear power. **(Policy Action 23)**

FortisBC also considers that the BC Energy Plan's treatment of BC Hydro's "heritage" resources has an impact upon FortisBC's resource planning process. The Government of British Columbia's 2002 Energy Plan legislated a "Heritage Contract" for an initial term of 10 years to ensure that BC Hydro's customers benefit from existing low cost "heritage" resources. With the 2007 BC Energy Plan, the Government confirmed the Heritage Contract in perpetuity to ensure all of BC Hydro's customers will continue to receive the benefits of this low-cost electricity for generations to come. FortisBC is a customer of BC Hydro's. As discussed in further detail in Section 6.1.2.2, FortisBC is addressing the implications of this issue in its negotiations with BC Hydro for the renewal of the existing Power Purchase Agreement between FortisBC and BC Hydro (the current term of which will expire in 2013).

3.5.2.2 Western Climate Initiative

In 2007 the Government of British Columbia joined the Western Climate Initiative (the "**WCI**"), which is a collaboration of certain Canadian provinces and US states[20] in a market-based climate program to reduce global warming pollution, promote a thriving economy and protect public health. The WCI is committed to the development of a broad multi-sector "cap and trade scheme" as part of a comprehensive regional effort to reduce emissions.

In August 2007, the WCI set an aggregate regional greenhouse gas emission reduction goal of 15% below 2005 levels by 2020. This regional goal is to be achieved by WCI partners through a cap and trade scheme, and complementary measures to reduce greenhouse gas emissions.

3.5.2.3 Greenhouse Gas Reduction Target Act

In 2007 the Government of British Columbia enacted the *Greenhouse Gas Reduction Targets Act,* S.B.C. 2007, c.42 (the "**GHG Targets Act**"). The GHG Targets Act sets targets that are among the most aggressive in North America for reducing greenhouse gases. Under the GHG Targets Act, British Columbia's greenhouse gas emissions are to be reduced by at least 33% below 2007 levels by 2020. A further emissions-reduction target of 80% below 2007 levels is set for 2050.

3.5.2.4 Carbon Tax Act

On May 29, 2008, the Government of British Columbia enacted the *Carbon Tax Act*, S.B.C. 2008, c.40 (the "**Carbon Tax Act**"), which imposes a broadly based carbon tax on the purchase and use in British Columbia of fossil fuels (such as gasoline, diesel, natural gas, heating fuel, propane and coal). The tax rates, effective July 1, 2008, are based on $10 per tonne of carbon dioxide equivalent (CO_2e) emissions from the combustion of each fuel. The proposed tax rates increase over the following four years, per year per tonne of CO_2 emissions. Specific tax rates will vary for each type of fuel, depending on the amount of CO_2e emissions released as a result of its combustion.

3.5.3 US Regulatory Framework

3.5.3.1 Increasing Reliance on Renewable Portfolio Standards

As of October 2008, thirty US states have passed legislation imposing Renewable Portfolio Standards ("**RPS**") on electric generation[21]. A Federal RPS initiative is also being considered. The targets[22] established in these various RPS initiatives are expected to promote a significant boost in the renewable components of each region's various generation base and to change the mix of generation technologies

[20] including British Columbia, Manitoba, Ontario, Quebec, Arizona, California, Montana, Oregon, New Mexico, Utah and Washington (with Saskatchewan, as well as additional US and Mexican states participating as "observer" jurisdictions)

[21] North American Electric Reliability Corporation, *2008 Long-Term Reliability Assessment*, October 2008, page 28.

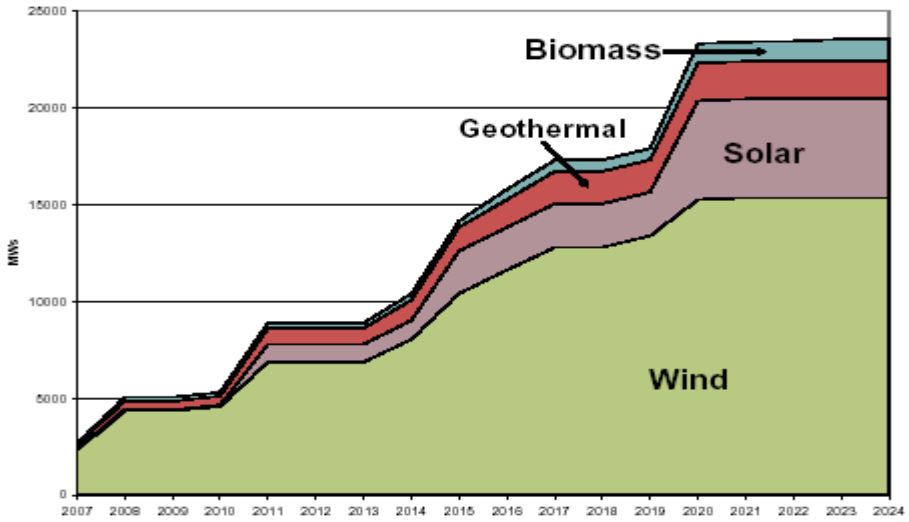
[22] The RPS targets vary, depending upon jurisdiction.

expected to be built over the next two decades. Figure 3.5.3.1 below illustrates the magnitude of the additions required. Assuming that each state's current RPS target will be met, nearly 30,000 MW of renewable generation will need to be added in the Western Electric Coordinating Council region[23] over the next 20 years.

In the Pacific Northwest, wind is the primary renewable resource capable of generating utility-scale power. To meet the new RPS requirements, Washington and Oregon together will have to add 10,500 MW of wind power by 2025.

A challenge created by the RPS initiatives' emphasis on wind power is that while wind can deliver utility-scale power, delivery is intermittent (that is, it is dependent upon the wind). An approximation of "firm" or dependable capacity from a wind generator is only 20% of its nameplate capacity. So, for example, if 1,000 MW of wind generation is installed, it can be relied upon only for about 200 MW of firm capacity. Similar considerations apply to other intermittent renewable resources. The cost corollary to this reality is that in addition to the capital invested to develop the intermittent renewable resource itself, additional capital is required to develop firm capacity-capable resources to deliver power when the renewable resource is unavailable.

Figure 3.5.3.1: Renewable Portfolio Standard Additions in WECC[24]



3.5.3.2 RPS Impacts on Demand-side Resources

RPS and related policies will also increase pressure on demand-side resources in the marketplace, since most RPS initiatives include demand-side as well as renewable resource requirements. In California, for

[23] The region for which the Western Electric Coordinating Council has responsibility includes British Columbia, Alberta, the northern portion of Baja California and all or portions of the fourteen western states in between.
[24] Puget Sound Energy, 2007 Integrated Resources Plan, page 2-2.

example, investor-owned utilities were to have spent $2 billion between 2006 and 2008 on energy efficiency[25].

3.5.3.3 State and Local Initiatives to Limit Greenhouse CO_2 Emissions

Washington, Oregon, and California have each proposed a number of emissions reduction projects under the "West Coast Governors Global Warming Initiative". Currently, both Oregon and Washington require new power plants to offset a certain portion of their anticipated CO_2 emissions. Similarly, the California Public Utility Commission requires that a "carbon adder" (an estimate of the cost of complying with future carbon emission limits) be used by the state's utilities when comparing the costs of alternative generation during resource planning processes.

Local jurisdictions in the Pacific Northwest have also been developing their own climate policies. For example, by 2007, 600 mayors had signed the U.S. Mayors Climate Protection Agreement, which seeks to reduce greenhouse gas emissions from the signatory communities by 7% from 1990 levels, by 2012.[26]

In May 2007, Washington State adopted a new law regulating greenhouse gas emissions (Senate Bill 6001). The law has two key components that affect electric utilities. The first component is a set of guidelines pertaining to emission rates for CO_2 from new electric resources (whether owned or contracted). The second component sets goals to reduce total greenhouse gas emissions in the state to 1990 levels by 2020, 75% of 1990 levels by 2035, and 50% of 1990 levels by 2050.

3.5.4 Summary

Across North America, various levels of government (federal, provincial / state and local) are enacting policies and legislation that seek to regulate greenhouse gas emissions. A complicating factor for industry as it attempts to comply with these new regulations is that recent and anticipated policy directions in Canada and the United States are not necessarily coincidental and are, indeed, in certain respects conflicting.

FortisBC expects that a co-ordinated system for regulated emissions trading[27] will ultimately emerge in North America. While there are several different trading schemes currently in effect, there is not yet a single, unified approach. While a variety of greenhouse gas emissions cost escalations have been suggested, no federal legislation has been enacted to date.

These governmental initiatives will inevitably carry an economic cost that must be considered in making resource planning decisions. Given the lack of comprehensive legislation, or a formalized cost structure

[25] California Public Utilities Commission, *Energy Efficiency California's Highest-Priority Resource*, June 2006.

[26] United States Conference of Mayors: *600 Mayors in all 50 States and Puerto Rico Take Action to Reduce Global Warming*, July 13, 2007

[27] "regulated emissions trading (or "cap and trade") is an administrative approach used to control pollution by providing economic incentives for achieving reductions in the emission of pollutants. http://en.wikipedia.org/wiki/Cap_and_trade

in British Columbia, and in order to maintain comparability and consistency in its assessment of resource options, FortisBC has utilized greenhouse gas cost values based on the Carbon Tax Act in assessing potential greenhouse gas – related costs in this 2009 Resource Plan.

Nevertheless, it should be noted that there remains considerable uncertainty as to the standards which will ultimately apply, and as to the potential economic costs of compliance with such standards.

3.6 Recent Resource Planning proceedings before the Commission

3.6.1 BC Hydro 2006 Integrated Energy Plan

In 2006, BC Hydro submitted to the Commission, for review, an Integrated Electricity Plan and a Long-Term Acquisition Plan. The regulatory review process culminated on May 11, 2007 in the Commission's issuance of Order No. G-29-07. The Reasons for Decision issued concurrently with G-29-07 reinforce the content of the Commission's Resource Planning Guidelines and are instructive for FortisBC in its own resource planning process in a number of respects, including the following:

- **Stakeholder involvement** – While the Commission instructs utilities to engage stakeholders in their resource planning, at the same time it requires those utilities to set the objectives and own the management of their respective plans.[28]

- **Load forecast instructions** – The Commission stated that "more than one forecast would generally be required in order to reflect uncertainty about the future: probabilities or qualitative statements may be used to indicate that one forecast is considered more likely than others."[29]

- **Portfolio analysis as part of the Resource Plan** – The Commission agreed that a portfolio analysis is consistent with the Commission's Resource Planning Guidelines.[30]

- **Self Sufficiency** – The Commission observed that the government's self-sufficiency policy applies to the province, not just to BC Hydro, and is targeted for achievement in 2016.[31]

3.6.2 BC Hydro 2008 Long Term Acquisition Plan

BC Hydro's 2008 Long-Term Acquisition Plan (the "**BC Hydro 2008 LTAP**") is a 10-year plan for meeting electricity demand in British Columbia. It is a follow-up plan to BC Hydro's 2006 Integrated Electricity Plan/Long-Term Acquisition Plan.

[28] BCUC *Decision on BC Hydro 2006 Integrated Energy Plan (IEP) and Long Term Acquisition Plan (LTAP)*. May 11, 2007, Page 31.

[29] BCUC *Decision on BC Hydro 2006 Integrated Energy Plan (IEP) and Long Term Acquisition Plan (LTAP)*. May 11, 2007, Page 43.

[30] BCUC *Decision on BC Hydro 2006 Integrated Energy Plan (IEP) and Long Term Acquisition Plan (LTAP)*. May 11, 2007, Pages 89, 90.

[31] BCUC *Decision on BC Hydro 2006 Integrated Energy Plan (IEP) and Long Term Acquisition Plan (LTAP)*. May 11, 2007, Page 128.

The BC Hydro 2008 LTAP includes the following targets:

- at least 50% of future incremental resource needs are to be met through conservation by 2020;
- 90% of electricity is to come from clean or renewable sources and all new electricity generation projects are to have zero net greenhouse gas emissions; and
- BC Hydro is to be self-sufficient by 2016.

BC Hydro anticipates that demand for electricity will grow by approximately 25 to 40% over the next 20 years, which (without taking into account the measures proposed by the BC Hydro 2008 LTAP) would result in an energy shortage of approximately 22,000 gigawatt hours (GWh) per year and a capacity shortage of 3,000 megawatts (MW) by 2028.

BC Hydro proposes to meet this projected growing demand for electricity through implementation of a variety of measures, including the following:

- Conservation, which is expected to save more than 10,000 GWh per year by 2020;
- BC Hydro will seek power from new sources of clean energy. This includes its Clean Power Call and its two-phase Bioenergy Call for Power;
- BC Hydro plans to continue to rely on the Burrard Thermal generating plant for capacity support and backup energy supply to the Lower Mainland / Vancouver Island region, at least until completion of the proposed Interior-to-Lower Mainland transmission line;
- BC Hydro will complete the definition phase work on “Mica Units 5 and 6”. This could lead to the addition of two generating units at the Mica Dam, which would add new long-term dependable capacity to the BC Hydro system;
- Project definition and consultation phase work on Site C will continue. Site C is a potential third dam on the Peace River, which would take advantage of the large amount of water stored upstream in the existing Williston Reservoir and would have an operating life of more than 100 years. Based on the proposed schedule, the earliest Site C could operate would be 2019; and
- Demand-Side Management. [32]

Final arguments have been filed.

[32] BC Hydro, *Conservation, clean resource options key elements of 2008 Long-Term Acquisition Plan*, press release dated June 13, 2008.

3.7 Stakeholder Consultation

FortisBC considers that the views and concerns of its customers constitute an important part of the overall context within which the Company makes power supply resource decisions. Accordingly, in developing this 2009 Resource Plan, FortisBC engaged in a multi-pronged stakeholder consultation process.

3.7.1 Local Government Presentations

The Company made presentations to the councils of 15 local government entities in its service territory, outlining the power supply / demand context, various resource options under consideration and certain resource portfolios having potential to close FortisBC's forecast energy and capacity gaps. In these presentations FortisBC also addressed the principal factors relevant to the planning process, including:

- energy and capacity gaps;
- environmental considerations;
- transmission considerations;
- economic considerations; and
- BC Energy Plan Policy Actions.

Participants consistently cited system reliability, the environment (and, in particular, green energy), cost, transmission-related impacts, and maximization of conservation efforts as relevant considerations for FortisBC's resource planning process.

Participants identified reliability of potential power sources as a key concern.

Participants expressed concern about the ramifications of changing environmental impacts upon power generation choices, and suggested FortisBC should consider diversifying its generation mix by including alternative sources such as wind energy. Participants also expressed concern about how to "back up" the intermittent nature of certain of such alternative sources. Some suggested that FortisBC consider creating storage capacity, such as new hydro projects, in order to meet that concern.

Participants recognized the challenges involved in balancing costs with environmental considerations, but recognized also that the longer the Company waits to solve its capacity and energy gaps, the greater will be the cost.

Potential transmission impacts (including cost, site-related, and environmental) emerged as a significant concern.

Participants advised FortisBC to do all it can to encourage conservation efforts and demand-side management, including taking measures such as:

- advanced metering to enable "time of use rates", stepped rates and peak control; and
- enabling of Distributed Generation resources such as solar, micro-hydro, bio-mass and co-generation.

3.7.2 Survey and Workshops

FortisBC also engaged Environics Research Group ("**Environics**"), a nationally-recognized opinion research organization, to assist in discovering and analyzing stakeholder perspectives. Environics' information-gathering on FortisBC's behalf took two forms:

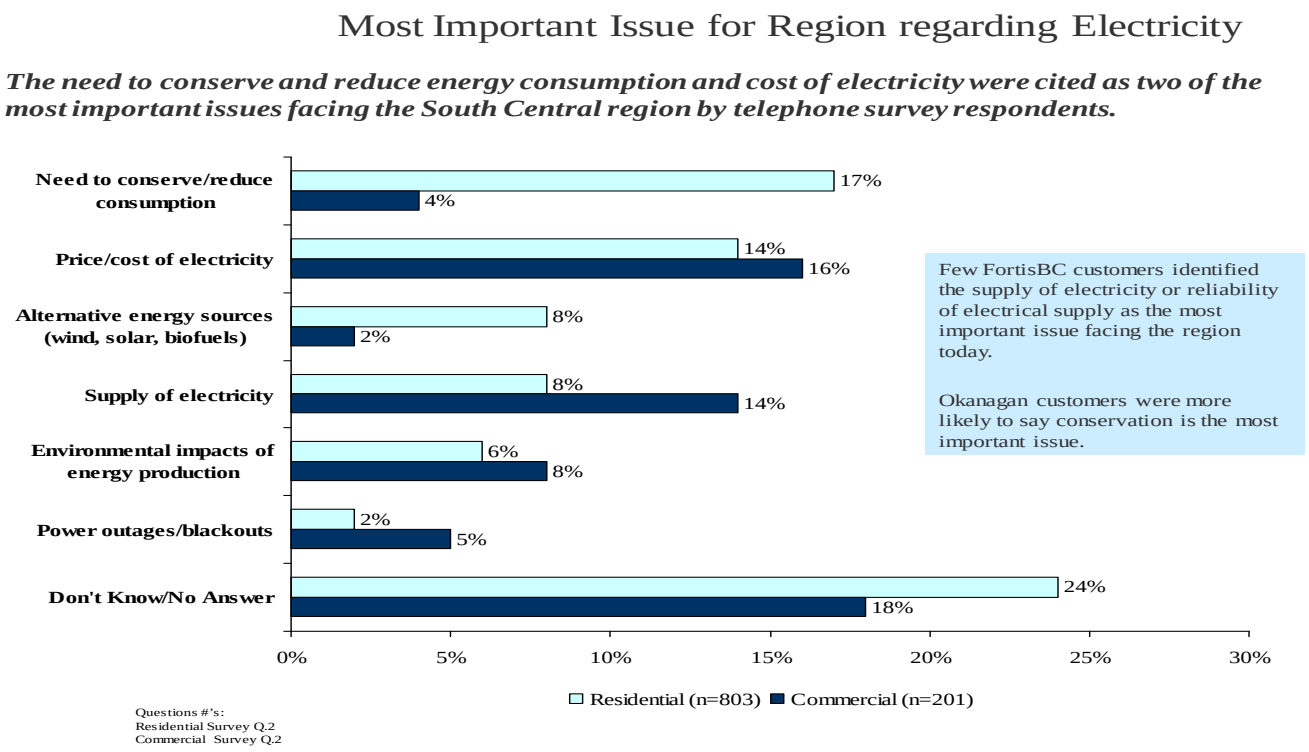
1. a broad-based telephone survey of FortisBC customers, and
2. two "workshops" entailing a pre-presentation questionnaire, a presentation by FortisBC (similar to that provided to local government councils), a question and answer period and a post-presentation questionnaire. This methodology specifically tested the impact of subject-matter education on stakeholder perceptions regarding potential resource solutions proposed by the Company.

The Environics report is attached as Appendix C.

In FortisBC's view, the workshop format was a successful method of achieving community involvement. Many workshop participants were complimentary of FortisBC's efforts to involve them in decision making and advised that they found the experience to be educational.

As Environics states in its report, Canadians typically cite the environment as one of the most important problems facing Canada today. Energy supply issues and conservation tend not to be as prominent. However, as shown in Figure 3.7.2 below, FortisBC's survey respondents cited conservation or reduced consumption and cost of electricity as two of the most important issues facing the region.

Figure 3.7.2: FortisBC Customer Issues Summary



When asked about different electricity supply options, FortisBC customers did not express any unified preference for any single option as the ideal solution. Of all supply options presented to study participants, wind power was favoured by residential and commercial telephone survey respondents as the option having least impact on the environment. Large hydro (both capacity and energy) was the highest-rated option for workshop participants, who believed it to be a clean source of energy with a low impact on the environment.

Purchasing electricity from the wholesale energy market was the least preferred option in both telephone surveys and workshops. Generating power within British Columbia rather than importing it from other jurisdictions and 'minimizing the impacts of power generation' were the top two 'critically important' considerations among telephone survey respondents. Workshop participants indicated that ensuring a reliable source of power was critically important to them.

Concerns about environmental impact were raised with all options.

It appears to FortisBC that workshop participants ultimately preferred supply options that were different to those preferred by telephone survey respondents because through the interactive workshop process participants developed greater understanding of relevant issues. Many workshop participants indicated

that they could understand the complexity of the challenges facing FortisBC. They also expressed a desire to see a wider exploration of the options.

Two-thirds of the residential telephone survey respondents who said that the generation of power created environmental damage in the region or in their community thought that the level of damage was 'fully or somewhat acceptable'.

Over 90% of FortisBC customers said that energy conservation would play a major or moderate role in ensuring a supply of power for the region. Over 90% of customers said that individual consumers can definitely or likely make an important contribution to reducing overall energy use.

3.8 Supply and Demand Overview

3.8.1 Western Grid Supply and Demand Overview

FortisBC is a member of the Western Electricity Coordinating Council ("**WECC**"), which is a voluntary organization responsible for co-ordinating and promoting electric system reliability in the region that includes British Columbia and Alberta, the northern portion of Baja California and all or portions of the fourteen western states in between. Among WECC's purposes are to support efficient, competitive power markets, to assure open and non-discriminatory transmission access among members, to provide a forum for resolving transmission access disputes and to provide an environment for co-ordinating the operating and planning activities of its members. WECC has been delegated authority from the North American Electric Reliability Corporation ("**NERC**") [33] to monitor and enforce compliance with United States reliability standards.

WECC operating practices include requirements relating to maintenance of Operating Reserve margins and automatic control systems on generators, as well as recommendations for longer term Planning Margins. (See Section 6.3 below for a discussion of FortisBC's proposed Planning Margin.)

Since the wholesale electricity market in the WECC region impacts the operation of FortisBC's own system, FortisBC's resource planning process must take into account both the existing generation that is in place (including expected additions), and the forecast load-resource balance, in the WECC region.

WECC published a "10-Year Coordinated Plan Summary: Planning and Operation for Electric System Reliability" in July 2006. (A copy is attached as Appendix D-1). Figure 3.8.1-A, below indicates the

[33] NERC, a nonprofit corporation based in Princeton, NJ, was formed by the electric utility industry to promote the reliability and adequacy of bulk power transmission in the electric utility systems of North America, NERC's mission states that it is to "ensure that the bulk power system in North America is reliable". NERC oversees eight regional reliability entities (including WECC) and encompasses all of the interconnected power systems of the contiguous United States, Canada and a portion of Baja California in Mexico. NERC's major responsibilities include working with all stakeholders to develop standards for power system operation, monitoring and enforcing compliance with those standards, assessing resource adequacy, and providing educational and training resources as part of an accreditation program to ensure power system operators remain qualified and proficient. NERC also investigates and analyzes the causes of significant power system disturbances in order to help prevent future events.

existing generation mix in the WECC region which, as of January, 2006, totals in the aggregate more than 188,000 MW of installed capacity.

Figure 3.8.1-A: 2006 WECC Generation[34]

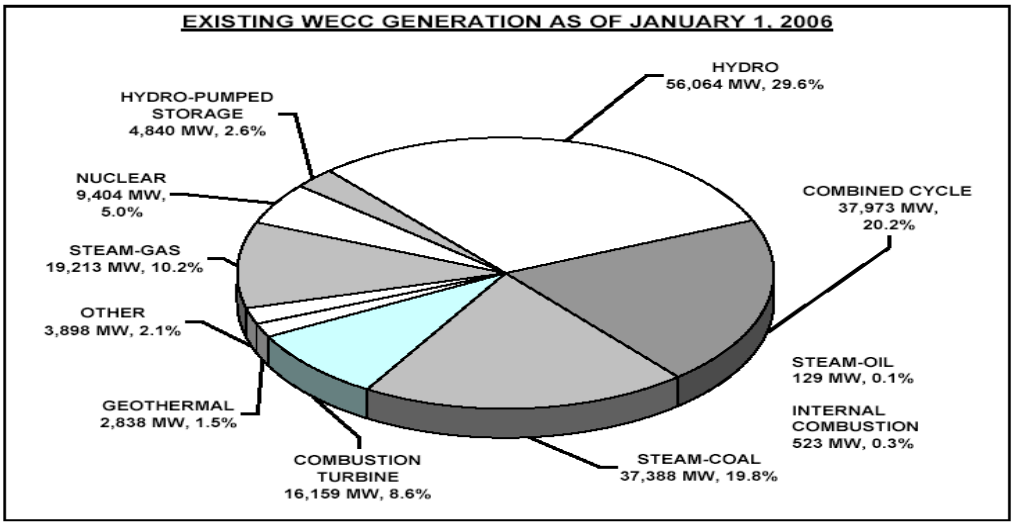
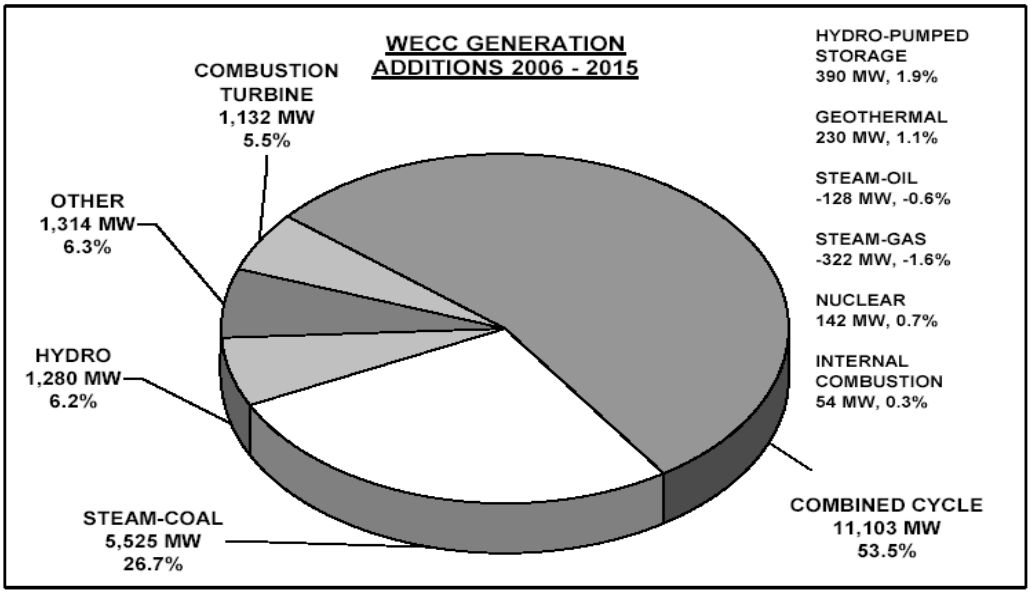


Figure 3.8.1-B below indicates the breakdown of expected generation additions in the WECC region during the period from 2006 to 2015, which in the aggregate totals a further 21,000 MW of capacity. It should be noted that Figure 3.8.1-B is taken from WECC's July 2006 report which predates the establishment of many of the RPS initiatives discussed in Section 3.5.3.1 above. RPS initiatives can, in FortisBC's view, be expected to increase the comparative size of the "other" category (by the addition of wind generation facilities, for example), generally at the expense of the "steam-coal" category. Development of the Combined Cycle Gas Turbine ("**CCGT**") category can be expected to remain consistent with the information set out below. However, a result of the RPS initiatives' focus upon intermittent renewable resources will be that as utilities retain capacity to back up their intermittent renewable resources, that capacity could become less readily available for sale on the wholesale electricity market.

[34] WECC *10-Year Coordinated Plan Summary* (Appendix D-1), page 33, WECC has not produced an update to this report as of May, 2009.

Figure 3.8.1-B: Expected WECC Generation Additions[35]



The Western Electricity Coordinating Council 2008 Power Supply Assessment (the "**2008 WECC PSA**"),[36] a copy of which is attached as Appendix D-2, is an assessment of generation resource capacity in the WECC region, with projections to 2017. The 2008 WECC PSA also includes an assessment of generation resource capacity margins for the various WECC sub-regions. Figure 3.8.1-C below displays the capacity margins by sub-region for summer and winter periods, respectively, showing which sub-regions have the potential for electricity supply shortages based on reported demand, resource, and transmission data.

According to the 2008 WECC PSA, a capacity margin equal to or greater than zero denotes that the load requirement is satisfied. A negative capacity margin means that the sub-region's generation and imports are less than its load requirement. Although the sub-region capacity margin varies significantly throughout the WECC region, the graphs for both summer and winter capacity margins demonstrate a general need for additional resources in the future.

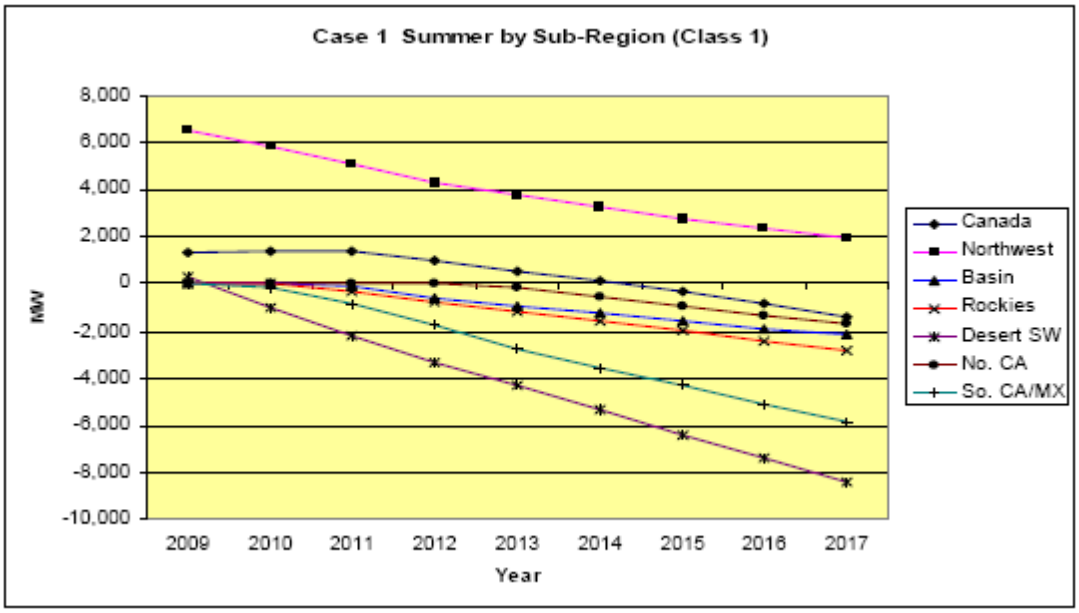
Specific to the "Canada" sub-region, summer capacity is expected to be sufficient until 2015, at which time current and currently planned resources will no longer provide sufficient capacity. The shortfall at that time is projected to be about 336 MW. Winter capacity in Canada is expected to be in deficit in 2009. By 2017, it is forecast that Canadian winter capacity will be in deficit by about 4,550 MW.

[35] WECC *10-Year Coordinated Plan Summary* (Appendix C-1), Page 34

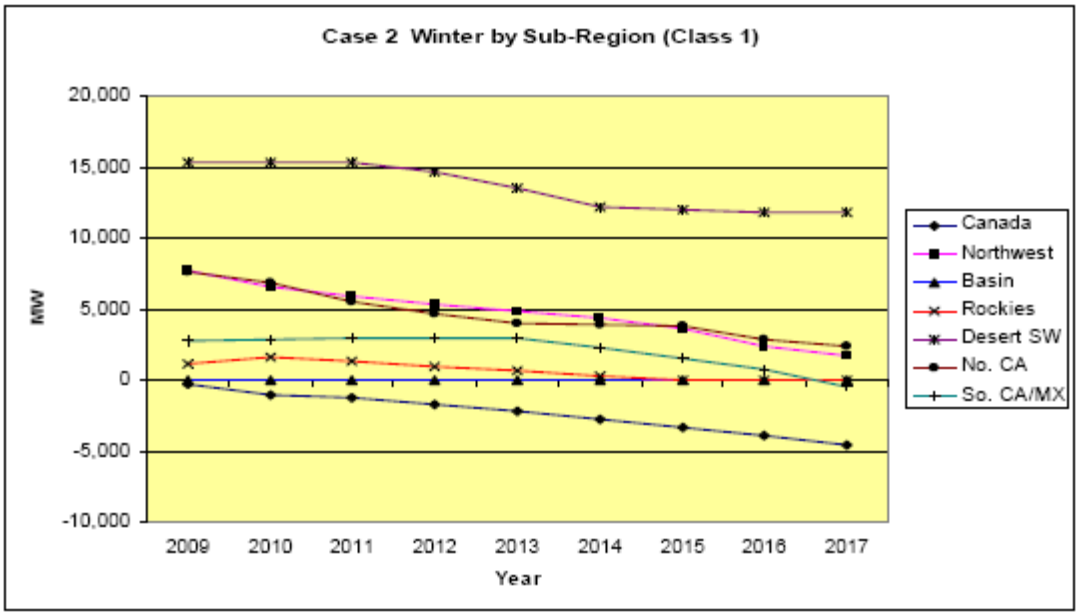
[36] WECC 2008 *Power Supply Assessment* (Appendix D-2), page 2

Figure 3.8.1-C: WECC Capacity Margins[37]

Graph 1 – Sub-Regional Resource Surplus/Deficit Summer Period[38]



Graph 2 – Sub-Regional Resource Surplus/Deficit Winter Period



The 2008 WECC PSA includes the following caveats[39]:

[37] WECC *2008 Power Supply Assessment*, Appendix D-2, Page 52

[38] FortisBC is included in the "Canada" sub-region

Transmission Constraints:

- "This assessment is based on the physical ability of the interconnection to supply all loads regardless of contractual obligations. This means that the model uses economic relationships to calculate transfers between zones within the assigned limits. In reality, the ideal solutions may be difficult to duplicate in the operational environment. System operation for contract obligations and other conditions could adversely affect the availability of resources, and could impact the amount and timing of power supply deficiencies in specific zones".

Capacity Constraints:

- "Surplus generation in the Pacific Northwest zone was often stranded due to transmission limitations... However, neither the summer nor the winter analysis for the Northwest sub-region captures the limitations on the ability of the hydro system to sustain output levels beyond a single hour. Because of this limitation, the reported surpluses, both for Northwest sub-region's load and for potential export to other sub-regions of the West, may be unrealistically high."

FortisBC acknowledges that the market environment has changed substantially since the publication of the 2008 WECC PSA . Specifically, FortisBC understands that the short term forecast gap between regional loads and resources has been reduced. The May 2009 forecast of the Energy Information Administration (US Department of Energy) notes that although energy consumption is expected to be reduced in 2009, it is expected to return to a more normal growth rate in 2010. [40] Given that the planning period of this 2009 Resource Plan is twenty years, and that it contemplates new resources that require extended implementation timeframes, FortisBC believes it is still prudent to continue to use WECC's long term assessment of the wholesale electricity market. On this basis, over the longer term, an overall tight supply is forecast in the WECC region.

While new renewable resources will be added to the regional system, most will have to be supported by some form of firm capacity resource. It appears to FortisBC that natural gas-fired firm capacity will be the most commonly-utilized resource in the WECC region for that purpose. (The relationship between gas prices and electricity prices will be discussed further in Section 4.2 below.)

3.8.2 BC Hydro Load and Resource Forecast

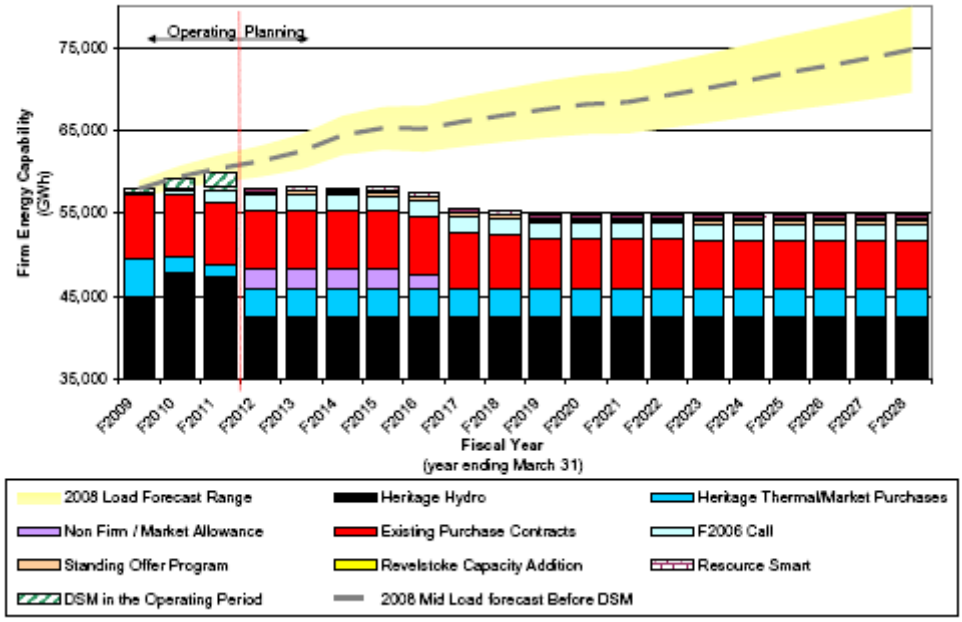
In the BC Hydro 2008 LTAP, BC Hydro set out its load and resource forecasts for both energy and capacity. Figure 3.8.2-A is a copy of BC Hydro's Energy Load Resource Balance, and Figure 3.8.2-B

[39] WECC *2008 Power Supply Assessment* (Appendix D-2), page 50

[40] Energy Information Administration *Short-Term Outlook*, May 12, 2009

1 below is a copy of BC Hydro's Capacity Load Resource Balance. In the case of both energy and
2 capacity, BC Hydro's plans call for new resources to meet forecast deficits.

3 **Figure 3.8.2-A: BC Hydro 2008 LTAP Energy / Load Resource Balance**[41]



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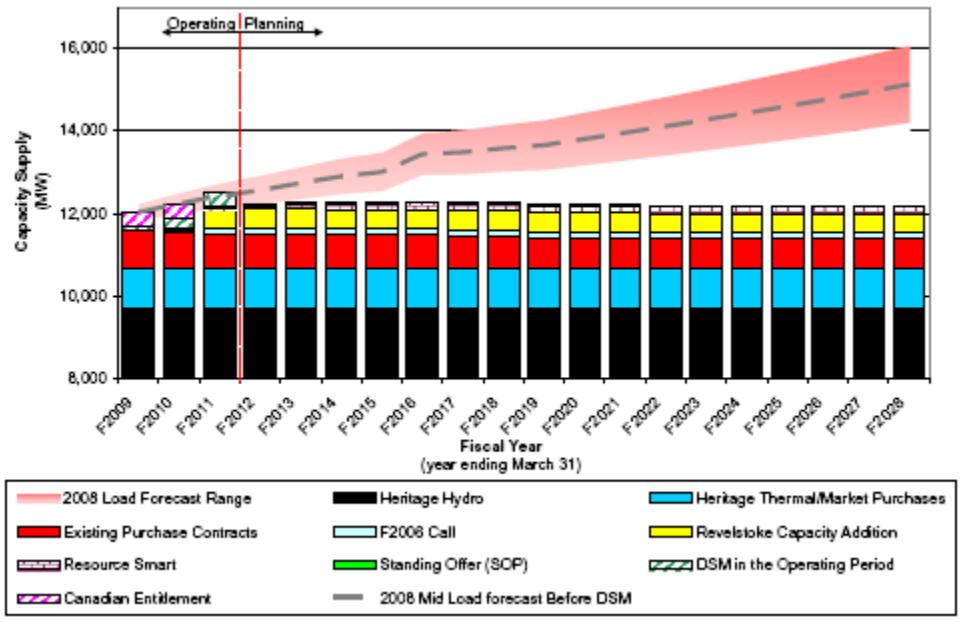
5 **Figure 3.8.2-B: BC Hydro 2008 LTAP System Dependable Capacity Load Resource Balance**[42]



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[41] BC Hydro *2008 LTAP Evidentiary Update*, December 22, 2008, page 17

[42] BC Hydro *2008 LTAP Evidentiary Update*, December 22, 2008, page 18

In 2008, FortisBC accounted for 191 MW of BC Hydro's total available capacity of 11,280 MW, and 826 GWh of BC Hydro's total domestic load of 53,300 GWh[43].

BC Hydro has stated that of its existing resources, heritage assets provide approximately 42,600 GWh of energy, and about 9,800 MW of dependable capacity.[44] Additionally, it has stated, "Heritage Assets are aging and many components of the system are nearing the end of their useful lives. As demand grows relative to supply, utilization of existing assets will increase and will result in less flexibility to deal with unexpected equipment failures."[45]

3.9 FortisBC Transmission Context

FortisBC believes that its resource planning process should include consideration of transmission planning issues. Depending on what choices are made, new generation resources could require significant new or upgraded transmission infrastructure or could, on the other hand, defer or eliminate otherwise necessary transmission infrastructure reinforcements. This Section 3.9 discusses the current state of the FortisBC transmission-related network, currently planned upgrades and the possible transmission costs associated with the addition of new generation resource options.

3.9.1 Existing Transmission System

FortisBC faces challenges related to the long-distance transmission of energy from point of generation to point of consumption. The geography of the FortisBC service territory is such that the majority of the Company's system load is in the Okanagan region while FortisBC's self-owned generating plants are on the Kootenay River in the West Kootenay region.

Until recently, much of FortisBC's transmission system was operated radially. For example, most of the FortisBC load in the South Okanagan was supplied directly from a single transmission line originating in the Trail area. With the completion of the Vaseux Lake Terminal Station in 2006, FortisBC's bulk transmission system can be operated fully meshed from FortisBC's Kootenay River generating plants through to Kelowna. This system meshing provides the benefits of improved system reliability and reduced transmission system losses.

FortisBC has recently added, or is in the process of adding, internal transmission capacity through the following projects:

- Kootenay 230 kV Project – completed in 2003
- South Okanagan (Vaseux Lake) Project – completed in 2006

[43] BC Hydro 2008 *Annual Report*

[44] BC Hydro 2006 *Integrated Electricity Plan*, section 4.4.3.2.

[45] BC Hydro 2006 *Integrated Electricity Plan*, section 4.4.3.3.

- Okanagan Transmission Reinforcement (OTR) Project – scheduled for completion in 2011

Combined, these three major projects create two strong 230 kV bulk-transmission networks: one in the Okanagan region and one in the West Kootenay region (please refer to simplified line diagrams shown below).

Figure 3.9.1-A: Okanagan Bulk Transmission Network (as of 2011)

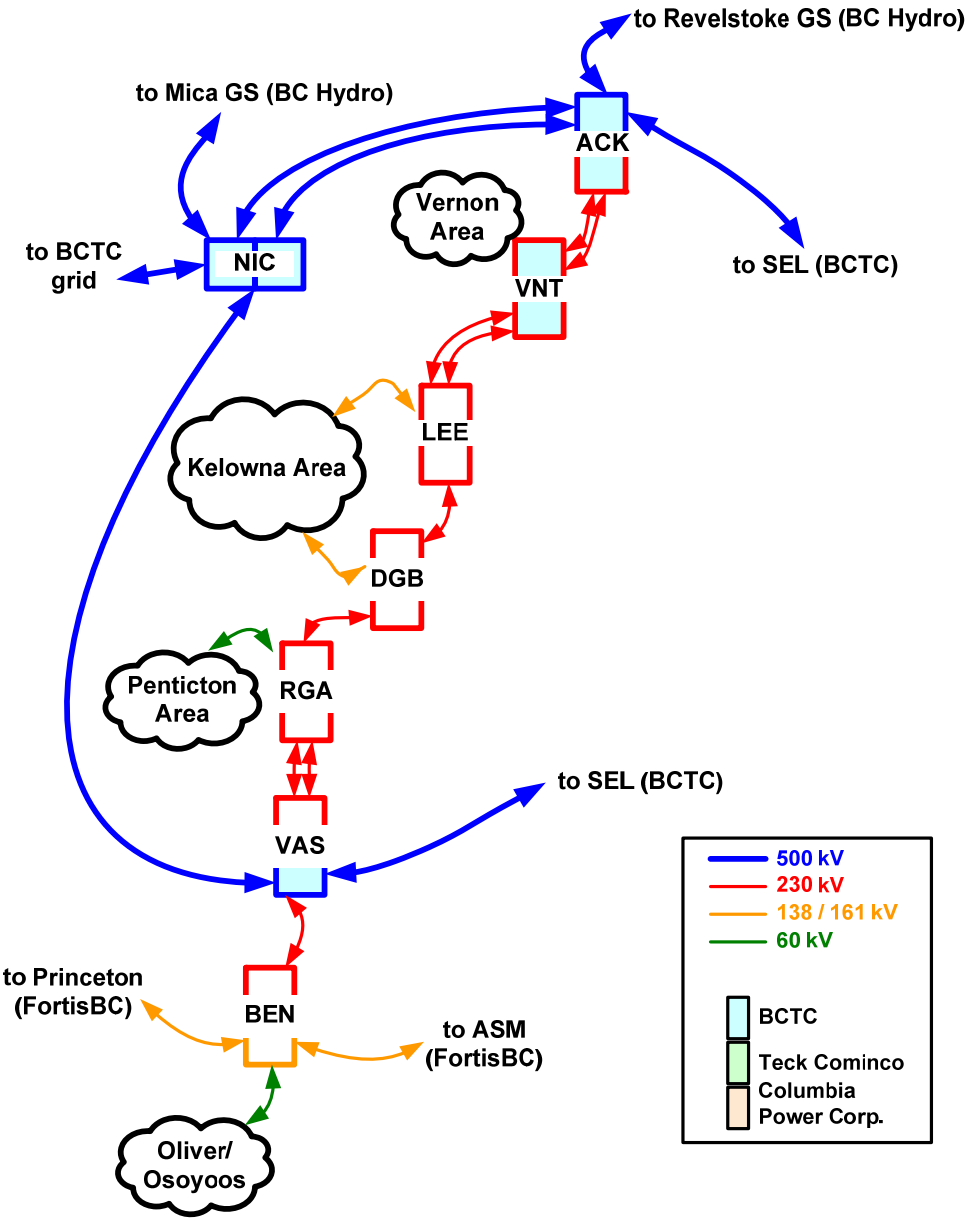
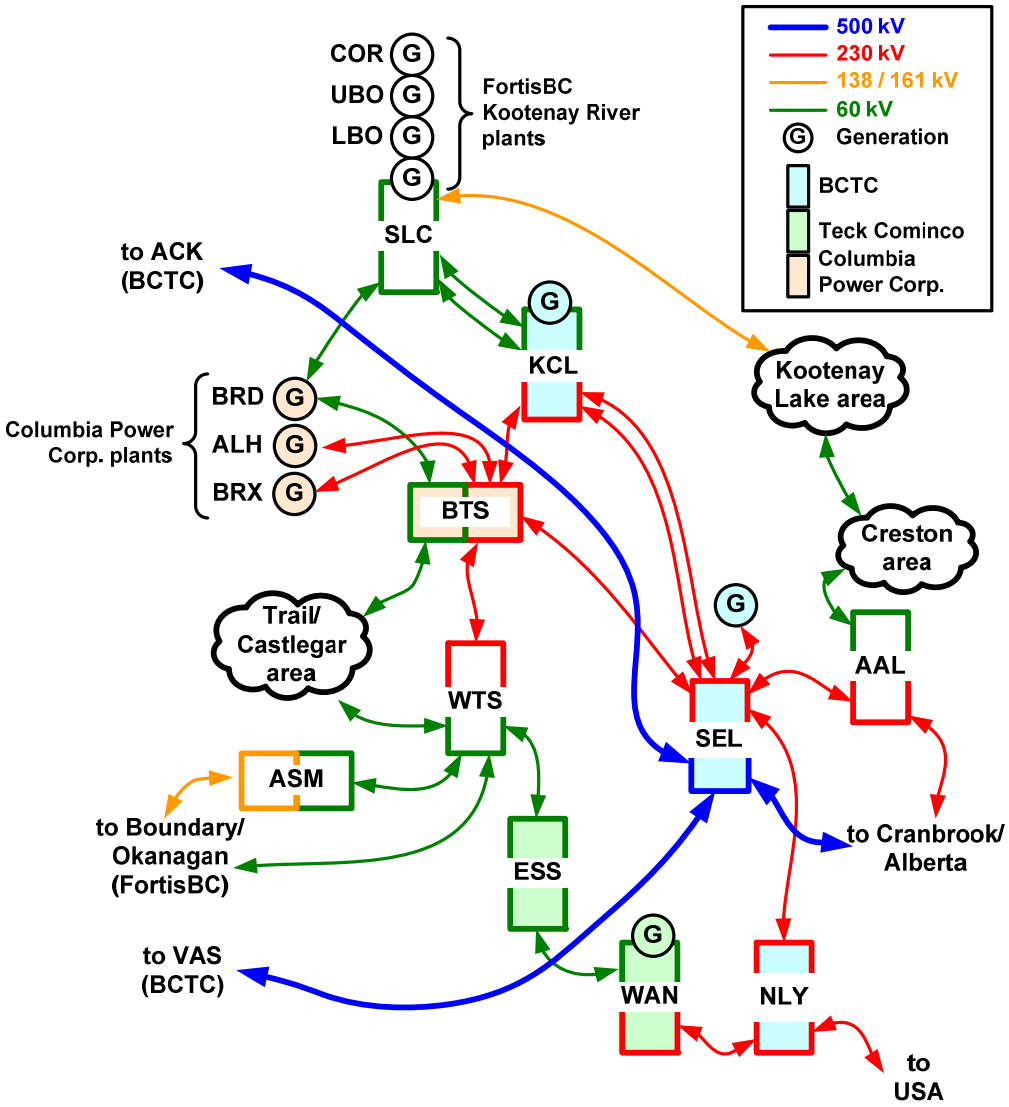


Figure 3.9.1-B: Kootenay Bulk Transmission Network



The only FortisBC-owned interconnection between these two regional networks is a single 161kV transmission line (being No.11 Line – shown in Figure 3.9.1-A above as running between the Bentley Station ("**BEN**") to the A.S. Mawdsley Station ("**ASM**") and in Figure 3.9.1-B above as running between the "ASM" station to "Boundary Okanagan"). The FortisBC transmission system is further supported by the British Columbia Transmission Corporation ("**BCTC**") transmission grid (overlaid on the FortisBC system in Figures 3.9.1-A and 3.9.1-B above). The FortisBC system is interconnected with the BCTC transmission grid at five major interconnection points: Kootenay Canal Generating Station ("**KCL**"), Vaseux Lake Terminal Station ("**VAS**"), Vernon Terminal ("**VNT**"), Selkirk Substation ("**SEL**") (via Arrow Lakes Power Corporation transmission line), and the Nelway Substation ("**NLY**") (via Teck's system). In addition, there are two lower capacity interconnections at Princeton and Creston which are typically only used radially to supply FortisBC load.

FortisBC's Okanagan region network has no generation resources. Thus, all demand in that region is met by external generation delivered either directly through the FortisBC transmission system or wheeled through the BCTC transmission system. BCTC's transmission system is responsible for the bulk of the transfers from the FortisBC generation plants to the Okanagan-area load centre.

The West Kootenay region has a smaller amount of load compared to the Okanagan region, but all of the FortisBC-owned generation plants are in this area. Additionally, the load is well distributed and thus there are fewer critical transmission paths as compared to the Okanagan system. Table 3.9.1-A shows an approximate breakdown of the system load and generation resources in these two regions.

Table 3.9.1: Generation and Load Distribution in the FortisBC System

Region	Generation	Load
Okanagan	0%	70%
West Kootenay	100%	30%
Total:	100%	100%

3.9.2 Near-Term Transmission System Constraints

FortisBC conducts annual assessments of the adequacy of its current and future transmission system. It does so to ensure that the system is compliant with industry standards for both current and forecast loads. The basic criterion is that the bulk electric system must be able to meet the expected system load for all hours of the year without violating transmission capacity limits. This criterion must be met with all transmission elements in service (N-0), and with any single transmission element out of service (N-1).

Transmission capacity limits manifest themselves in one or more of following ways:

- violations of equipment (e.g. transmission line or transformer) thermal ratings;
- violations of steady-state voltage limits; and
- violations of voltage and/or transient stability limits.

When any of these conditions is identified, a mitigation solution must be developed. This would typically require infrastructure additions or upgrades. FortisBC currently expects its transmission system to experience limits starting in about 2011, as discussed in further detail in the following sections.

3.9.2.1 West Kootenay region

In normal operation (all transmission elements in service), the West Kootenay region transmission system is capable of meeting the area load requirements well beyond the planning period of this 2009 Resource Plan. Thus, FortisBC plans no major reliability-driven transmission reinforcements in the West Kootenay region for the next 20 years. From a reliability perspective (N-1 or greater contingencies), outages typically result in overloads due to excess generation, not excess load. These events are typically dealt

with by Remedial Action Schemes or Special Protection Systems which shed an appropriate amount of generation.

3.9.2.2 Okanagan Region

In normal operation (all transmission elements in service) the Okanagan region transmission system is capable of meeting the area load requirements until demand in the combined Kelowna / Penticton area exceeds approximately 680 MW. Current load forecasts show this level being exceeded in approximately 2020. (These forecasts assume the completion of the Okanagan Transmission Reinforcement Project, but no further transmission system improvements in the Okanagan region.)

Prior to 2020, the Okanagan transmission system will fail to meet N-1 reliability when the combined Kelowna / Penticton area demand exceeds approximately 615 MW. This load level is currently forecast to be reached in about 2015. A localized N-1 capacity violation occurs in the Kelowna area in approximately 2011/2012 as a result of insufficient transformation capacity. Finally, an N-1 capacity violation occurs throughout the Okanagan region in approximately 2016 as a result of insufficient transformation capacity at the Vaseux Lake Terminal Station.

Owing to the above system limitations, some form of area reinforcement will be required in the Okanagan Region. The following sections discuss some specific transmission limitations and possible mitigation solutions.

3.9.2.2.1 Reactive Support in the North Okanagan area

As the Okanagan load continues to grow, voltage violations will begin to occur following certain critical N-1 outages. As discussed above, these violations will begin to occur when the combined Kelowna / Penticton area demand exceeds approximately 615 MW (currently forecast to occur in about 2015).

The most cost-effective form of reinforcement in this case is to add reactive support to the transmission system. This is a relatively low-cost method of increasing capacity without having to add additional transmission lines. This approach has limited utility, however, since at some threshold the addition of further reactive support becomes ineffective and reinforcements need to consist either of construction of new transmission lines or conversion to higher voltage transmission.

To provide this reactive support, FortisBC has previously identified the need for a 150 Mvar static var compensator ("**SVC**") to be located in the Kelowna area. A high-level cost estimate for this installation is approximately $35 million (2009 dollars) and, based on current load projections, will be required prior the 2013/14 winter peak in order to maintain N-1 reliability.

However, if firm resources were added in the Kelowna area, they could have the additional benefit of providing or maintaining full N-1 reliability. This would allow deferral or elimination of the SVC installation

(providing a further financial benefit). Thus, new resource portfolios should be evaluated (among other criteria) in terms of their ability to allow deferral or elimination of the cost of installing the SVC.

3.9.2.2.2 Fourth 230/138 kV transformer in the Kelowna area

In addition to the reactive support described in the previous section, there will be a requirement to add a fourth 230/138 kV step-down transformer in the Kelowna area when the demand exceeds approximately 360 MW (currently forecast to occur in about 2011/12). The three existing transformers provide 536 MVA of total transformation capacity and 336 MVA of firm capacity. The additional transformer is needed to meet the N-1 planning criterion following the most severe single contingency (the loss of D.G. Bell Transformer 2) when the peak demand exceeds 336 MVA. The cost of installation of this transformer is estimated at $8 million (2009 dollars), at a conceptual level, depending on where the transformer is sited.

However, if significant firm resources were added in the Kelowna area, they might allow deferral or elimination of the fourth 230/138 kV transformer installation. Thus, new resource portfolios should be evaluated (among other criteria) in terms of their ability to allow deferral or elimination of the cost of installing the transformer.

3.9.2.2.3 Third transformer addition at Vaseux Lake Terminal Station

There are presently two 250 MVA 500/230 kV transformers installed at the Vaseux Lake Terminal Station. As the Okanagan load continues to grow, a thermal limit violation of one of the transformers will occur following the loss of the second transformer at peak times. Current load forecasts show this overload occurring in approximately 2016/17. Thus, a third transformer will need to be installed at Vaseux Lake prior to that time to maintain N-1 compliance. The estimated cost for the installation of the transformer and associated equipment is $8 million (2009 dollars).

However, if firm resources were added in the Okanagan area, they would have the benefit of reducing the load on the Vaseux Lake transformers. This might allow deferral or elimination of the third transformer installation. Thus, new resource portfolios should be evaluated (among other criteria) in terms of their ability to allow deferral or elimination of the cost of installing the transformer.

3.9.2.2.4 Supply reinforcement to North Okanagan area

Once the Okanagan Transmission Reinforcement Project is complete there will be three strong 230 kV transmission sources for the Kelowna area: two transmission lines from Vernon and one transmission line from Penticton. Currently, contractual agreements with BCTC limit FortisBC's imports from Vernon to approximately 330 MW. As the Kelowna load continues to grow, this limit will be exceeded during peak times. This is especially true following a single-contingency outage of the Kelowna-Penticton transmission line when all of the Kelowna area load must be supplied from Vernon. Current forecasts show the limit

being violated in approximately 2013/2014 for N-0 operations and 2010/11 during N-1 contingencies. Resolving this issue will require joint planning discussions between BCTC and FortisBC to determine if the limit can be increased and to settle on the nature of any associated system reinforcements.

The timing of when this limit will be exceeded depends on both the Kelowna peak demand and the supply capacity of the BCTC system in the Vernon area. BCTC has indicated there may be some opportunity to marginally increase the limit, subject to the outcome of detailed planning studies. Beyond that point infrastructure upgrades will be required.

There are a number of possible solutions to this capacity problem. However, all are costly and involve significant amounts of new infrastructure. Table 3.9.2.2.4 below lists a number of possible supply reinforcements to the Vernon/Kelowna area along with their respective estimated costs.

Table 3.9.2.2.4: Recap of Possible Supply Reinforcement Costs

	Project Description	Estimated Cost (conceptual level)
1.	Construction of a second 230 kV line from Kelowna to Penticton	$70 million
2.	Construction of a third 230 kV line between Ashton Creek and Vernon (BCTC-owned line)	$70 million
3.	Construction of a third 230 kV line from BCTC between Ashton Creek and Kelowna (FortisBC-owned line)	$90 million
4.	Construction of a new 500/230 kV supply source in the Kelowna area	$500 million

Numerous factors need to be considered when selecting from the above options. These include:

- the remaining supply capacity (if any) in BCTC's Vernon system;
- the project capital cost and associated rate impact;
- environmental and land issues (i.e. new rights-of-way for transmission lines, etc.);
- any consequential benefits such as improvements in provincial transmission capacity; and
- the length of time for which the project will provide sufficient capacity.

Further, a balancing of objectives relating to these factors may be required. For example, the lowest capital cost project with the least environmental impact may also have the shortest useful lifespan and thus in the long term have a higher total cost (since additional reinforcement may be required sooner).

However, as discussed above in this Section 3.9.2, instead of immediately reinforcing the transmission system through implementation of any of these options, FortisBC might add firm generation resources in the Kelowna area, thereby deferring or eliminating the need for additional transmission infrastructure. Given the uncertainty of the load growth, project timing and costs, it is difficult to assign a value to such deferral or elimination. However, given the scale and range of the potential capital expenditures

associated with the options enumerated above (between $70 million and $500+ million) this issue should be given consideration in the selection of a preferred resource portfolio.

3.9.2.2.5 Double contingency reliability for the Kelowna area

Currently, there is very little coverage for double-contingency (N-2 or N-1-1) events that affect the transmission supply to Kelowna from Vernon. In other words, if the two 230 kV supply lines from Vernon are unavailable for any reason, only a small portion of the Kelowna load can be supplied via the remaining 230 kV transmission line from Penticton. This issue will be substantially resolved by the completion of the Okanagan Transmission Reinforcement Project.

In Order C-5-08 and its accompanying decision, the Commission agreed – based on the historical frequency of the loss of two supply lines from Vernon and the consequences of losing those lines to the loss of load in Kelowna – that the Okanagan Transmission Reinforcement Project was in the public interest. However, the Commission also cited from its previously issued letter L-48-05 to FortisBC:

> "[The Okanagan Transmission Reinforcement Project] *would have the result of increasing the level of reliability for Kelowna beyond what is commonly referred to as an N-1 contingency level but this outcome should not be interpreted as meaning the Commission Panel has set increased design standards of reliability for the City of Kelowna or for other similar load centers.*" [excerpt from BCUC letter L-48-05].

Additionally, in this decision the Commission expressly stated that it does not support the double-contingency reliability planning criterion. On this basis, FortisBC has no future projects planned that would have only the benefit of improving or providing N-2 reliability for the Kelowna area.

One of the outcomes of the Okanagan Transmission Reinforcement Project is that it will greatly improve coverage for Vernon to Kelowna N-2 outages (from approximately only 10% of the year in 2009, to approximately 98% in 2011). Thus, there will still be a number of hours (approximately 175 hours) per year where insufficient N-2 transmission capacity exists to meet the combined Kelowna/Penticton load. A similar problem would occur following an N-2 outage of the 230 kV double-circuit between Vaseux Lake and Penticton. For this latter scenario, all of the Kelowna/Penticton load would need to be supplied from the BCTC Vernon source. (The limits associated with this interconnection are discussed in the previous section.)

As discussed, FortisBC currently plans no transmission system improvements to mitigate these N-2 deficiencies. However, if firm capacity generation resources were added in the Kelowna area, they could have the additional benefit of providing or maintaining full N-2 reliability for little or no incremental cost. Even for non-firm resources, some level of N-2 reliability would be provided while the resources were

online. Thus, appropriate siting of new generation could provide consequential transmission reliability improvements and should be considered in the evaluation of new resource portfolios.

3.9.3 FortisBC Transmission System Summary

From a transmission planning perspective, FortisBC's service territory consists of two distinct regions: the Okanagan region and the West Kootenay region. The West Kootenay region can be considered as a "generation-surplus" region with no requirement for reliability or capacity driven reinforcement within the planning period of this 2009 Resource Plan. By contrast, the Okanagan region faces both reliability and capacity constraints within the planning period of this 2009 Resource Plan. In normal operations (all transmission elements in service) the Okanagan system is forecast to accommodate load growth until 2020. Past that time, new supply solutions will require new transmission infrastructure, and there are a number of potential solutions to this issue – as set out in Table 3.9.2.2.4 above – with costs ranging from $70 million to $500 million+. There are also reliability-related, and local area (Kelowna) load reinforcements required. These forecast reinforcements are summarized as follows:

Table 3.9.3: Transmission Timing/Cost Summary

Type	In-Service	Capital Cost ($2009)
Kelowna Transformer	2011	$8 million
150 MVar static var compensator (SVC)	2013	$35 million
Vaseux Transformer	2016	$8 million
New Supply	2020+	$70 million - $500 million+

While, due to the time required to place new generation resources, the Kelowna-area transformer cannot be avoided, a Kelowna-area new generation resource would provide potential to defer or eliminate the installation of the Vaseux transformer and the SVC, in addition to its inherent contribution to a solution for new supply requirements.

4 ELECTRICITY MARKET ANALYSIS

FortisBC relies on the wholesale electricity market to meet an increasing proportion of its capacity and energy requirements. The Company feels its strategy of making market purchases to close the gap between its supply and demand has generally been successful. Nevertheless, in its 2005 Resource Plan the Company stated its intention to conduct a study of the wholesale electricity market in the WECC region in order to assess the continuing viability of its market purchase strategy. In the Action Plan set out in FortisBC's 2005 Resource Plan, therefore, the Company undertook to complete such a study.

The Company engaged Willis Energy Services Ltd. to complete a wholesale electricity market analysis. That analysis (the "**Willis Market Analysis**") was completed in August 2007. Section 4 of this 2009 Resource Plan summarizes the results of the Willis Market Analysis, and a complete copy of the Willis Market Analysis is contained in Appendix E.

The Company acknowledges that certain aspects of the market environment, such as regional load / resource gaps, have changed substantially since the preparation of the Willis Market Analysis. However, given that the planning period of this 2009 Resource Plan is twenty years, FortisBC considers that the information provided by the Willis Market Analysis is still relevant for purposes of the Company's resource planning process.

4.1 Available Market Supply Sources

As a member of WECC, FortisBC can draw upon a large wholesale electricity market to serve its load requirements. Energy and capacity are available from that market on any of the following bases:

- surplus power is typically available from hydroelectric plants during the spring freshet[46] or on an annual basis during years of above-average precipitation;
- capacity and energy are available from some gas generation projects;
- operators of large coal-fired and nuclear facilities prefer to operate them on a continuous basis — therefore, surplus power from these facilities is usually available during off-peak hours;
- various utilities will have surplus power available from time to time from their generation systems because their own load is not as high as forecast; and
- some utilities (BC Hydro being the most prominent) can store energy and capacity in their hydroelectric resources and are usually able to provide power to the market for the right price or to purchase power from the market at the right price.

[46] Runoff from melting snow

4.1.1 Constraints on Market Availability

Certain constraints limit the availability of power in the wholesale electricity market. Among these constraints are price volatility, market shortages and transmission system transfer limits. Each of these factors is discussed in turn in the following sections.

4.1.1.1 Price Volatility

Significant price volatility typically characterizes wholesale electricity markets. Figures 4.1.1.1-A and 4.1.1.1-B below graphically demonstrate price volatility in the Mid Columbia and Alberta markets, respectively (the two wholesale electricity markets that are geographically closest to FortisBC's service territory). Tables 4.1.1.1-A and 4.1.1.1-B below summarize the extremes experienced in the Heavy Load Hours and Light Load Hours electricity prices for both Mid Columbia and Alberta Power Pool from 2003 to 2008.

Figure 4.1.1.1-A: Price Volatility in Mid Columbia Market, November 2007 to April 2008

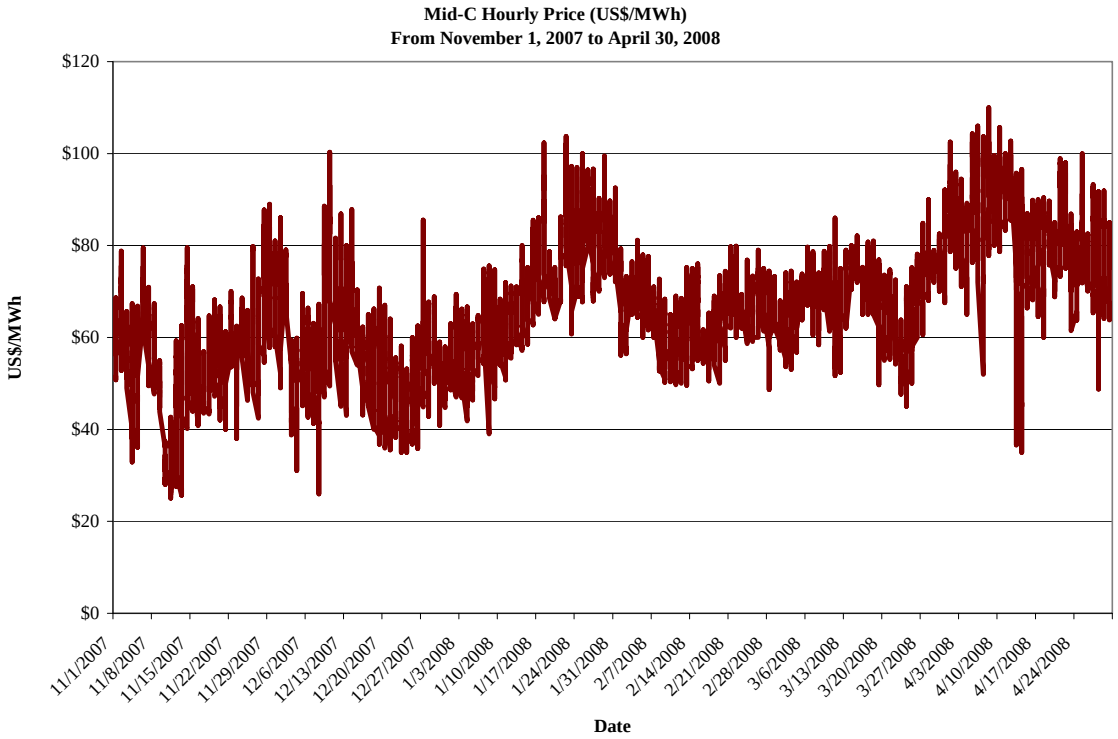


Figure 4.1.1.1-B: Price Volatility in Alberta Market, November 2007 – April 2008

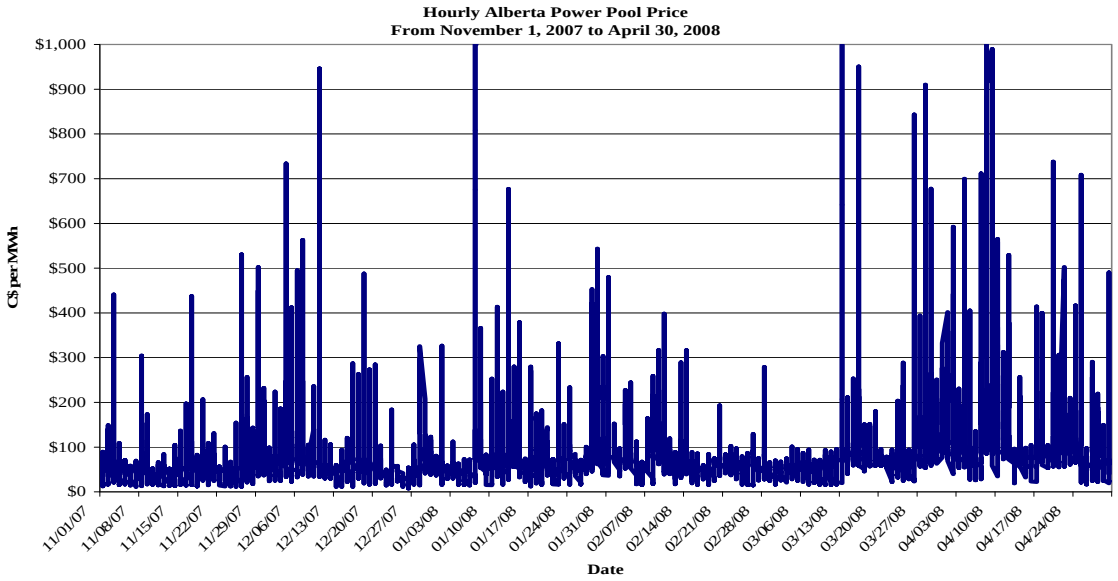


Table 4.1.1.1-A: Price Volatility – Light Load Hours, 2003 to 2008

Year	Mid-Columbia Hourly Price (US$/MWh)			Alberta Power Pool Price (C$/MWh)		
	Average	Minimum	Maximum	Average	Minimum	Maximum
2003	$31.30	$0.00	$95.38	$41.42	$7.07	$687.25
2004	$37.09	$4.82	$69.00	$34.92	$0.00	$411.51
2005	$49.39	$6.72	$150.00	$39.31	$7.48	$533.52
2006	$36.22	$1.22	$157.05	$39.68	$4.61	$986.84
2007	$41.01	$1.00	$81.37	$33.42	$0.00	$480.26
2008	$57.87	$0.38	$102.76	$53.62	$0.00	$502.85

Light Load Hours are 01:00 - 06:00 and 23:00 - 24:00

Table 4.1.1.1-B: Price Volatility – Heavy Load Hours, 2003 to 2008

Year	Mid-Columbia Hourly Price (US$/MWh)			Alberta Power Pool Price (C$/MWh)		
	Average	Minimum	Maximum	Average	Minimum	Maximum
2003	$37.77	$0.00	$120.57	$73.73	$7.07	$999.99
2004	$42.56	$3.80	$85.13	$64.45	$0.00	$998.01
2005	$59.52	$5.00	$167.51	$85.86	$4.66	$999.99
2006	$46.62	$1.49	$408.85	$101.41	$5.47	$999.99
2007	$52.72	$2.40	$187.97	$85.70	$0.00	$999.99
2008	$66.99	$1.05	$110.00	$115.81	$7.74	$999.99

Heavy Load Hours are 07:00 - 22:00

*** Mid-Columbia Hourly Prices for 2008 are from January 1, 2008 to June 10, 2008**

*** Alberta Power Pool Prices for 2008 are from January 1, 2008 to June 11, 2008**

4.1.1.2 Market Shortages

Shortages (that is, differences between supply and demand) can be caused by a number of factors, including extreme or extended weather conditions (which can create higher than planned demand) the effects of hydrology (resulting from periods of low precipitation, for example, which can reduce supply), generation unit or transmission outages (which reduce supply), and structural changes in load growth. The financial impact of a shortage is felt immediately by an electric utility that has insufficient capacity or an inadequate Planning Margin and which must, therefore, have recourse to the wholesale electricity market to close the gap between its supply and demand. For example, in July 2006 FortisBC experienced load 20% higher than the previous year's average July load, and 8% higher than on the

previous year's hottest summer day, resulting in the need to make an unanticipated wholesale market purchase of 1,680 MWh at an average price of $225 per MW.

Market shortages do not, in and of themselves, inevitably result in the construction of new supply resources. Legislative or regulatory constraints may limit the types of resources that can be constructed. Further, new generation projects typically require lengthy planning and construction timeframes. Regulatory uncertainty or changing market rules (as described in Section 3 above) may impair developers' ability to finance projects. Also, the high cost of new electricity generation relative to existing regulated prices means that long term supply contracts for the new project's output are normally a necessary precondition to the viability of new generation projects.

Section 3.8 of this 2009 Resource Plan reviewed the long term supply and demand outlook for the WECC region, which most strongly impacts FortisBC's potential market purchases. Despite short-term improvements in the regional load / resource balance arising from recent economic conditions, FortisBC believes that, as reflected in the WECC 10-Year Coordinated Plan Summary, over the longer term, supply in the WECC region will be increasingly tight.

Consequently, FortisBC concludes that it is no longer reasonable to expect supply from the wholesale electricity market to be available, at a stable price, and on a reliable basis.

4.1.1.3 Transmission Considerations

A further key consideration for FortisBC is the transmission transfer limit at the three interconnections on the British Columbia / United States border[47] and at the two interconnections on the British Columbia / Alberta border.

For the British Columbia / United States border the total transfer limit north into British Columbia is 2,000 MW and south into the United States is 3,150 MW. These limits reflect the combined capability of the two 500 kV lines between BC Hydro's Ingledow substation and Bonneville Power Administration's Custer substation, and the two 230 kV lines near Trail, British Columbia, between Boundary and Nelway.

For the British Columbia / Alberta border the total transfer limit west into British Columbia is 450 MW while the limit from British Columbia east into Alberta is 545 MW. These limits reflect the combined capability of the two 138 kV lines and one 500 kV line connecting the Alberta and BC Hydro integrated systems.

Both the British Columbia / Alberta and British Columbia / United States interconnections are often at their maximum limits and wheeling transactions between utilities in the region can be prevented by these limits. Also operative are the WECC-wide transmission constraints described in detail in Section 3.8.1 of

[47] Including the one merchant transmission line, owned by Teck Resources Limited at Trail, BC.

this 2009 Resource Plan. Given that a source of wholesale market electricity for FortisBC is the United States, these constraints are becoming increasingly significant for FortisBC. Further, as power generation and power demand in the WECC region continues to grow, FortisBC expects that, absent construction of new transmission infrastructure, transfer constraints will become more severe.

It should be noted that FortisBC has no transmission facilities that connect directly with any external market. Accordingly, the Company is dependent on the availability of adequate third party transmission capacity to serve its needs.

In summary, transmission considerations call into question the long term availability, on a reliable basis, of wholesale market electricity to service FortisBC's customers.

4.2 Fundamentals of Market Pricing

When reviewing historical wholesale electricity prices and forecasting future prices in the WECC region, the following market fundamentals should be taken into account.

4.2.1 Precipitation

32% of the generating capacity in the WECC region (and 46% in the Pacific Northwest)[48] is hydroelectric[49]. Variations in annual precipitation can cause significant variations from year to year in the energy available. For example, the energy available from BC Hydro's hydroelectric resources varied from 36,462 GWh in the driest year to 55,856 GWh in the wettest year[50].

There are a number of distinct weather regions in the WECC area, and the amount of hydro power available in any year can vary from region to region. A region experiencing a high precipitation year may have surplus power available for the wholesale market. Conversely, in low precipitation years there may be less power available. Since markets in the Pacific Northwest depend so heavily on hydro-electric generating resources, precipitation must be considered as a variable – independent of load growth – when assessing reliability of supply. Of course, precipitation's effect on adequacy of supply from the market also has a concomitant effect on price.

[48] WECC *2008 Power Supply Assessment*, (Appendix D-2), page 83 (hydro resources / total resources)

[49] WECC *10-Year Coordinated Plan Summary* (Appendix D-1), page 33

[50] BC Hydro *Power Supply Operations – Annual Review 1996/97*

4.2.2 Natural Gas Price

39% of the generating capacity in the WECC region is from natural gas fired generating plants. In general, these plants are the last plants within the resource stack to come on-line.[51] When they do come on-line, the operator can bring any surplus plant capacity into service to supply the market.

The decision as to whether a plant owner uses such a facility to supply the market will depend on the price of natural gas (which has historically been difficult to predict) and the efficiency or heat rate of the plant involved. In addition to the fuel component of operating a gas fired plant, there are additional non-fuel operating and maintenance costs. Overhaul periods and costs, for example, are dependent on operating hours. This topic is more fully developed in the Willis Market Analysis contained in Appendix E.

4.2.3 Long Term Electricity Price

The marginal cost of electricity is ultimately based upon the cost of new supply. However, given the development time necessary for new supply, market equilibrium (cost of electricity relative to cost of new supply) is not instantaneous. Therefore, although the cost of new supply is not directly related to the real-time market price, it is a key reference point. If, for example, the real-time price is much higher than the cost of new supply, power sellers (realizing that the price at some time will fall) are more likely to accept long-term contracts at prices below the real-time price. However, if the real-time price is much lower than the cost of new supply sellers will be less likely to commit to long-term contracts because they realize that prices will eventually rise.

4.3 Electricity and Natural Gas Price Forecasts

4.3.1 Natural Gas Price Forecast

The price of electricity and the price of natural gas are intimately linked. As noted in Section 4.2.2 above, 39% of existing generation supply in the WECC region is natural gas-fired. And, as described in Section 3.8.1 above, almost 60% of new resources in the region will also likely be natural gas-fired. Consequently, electricity prices will be driven to a large extent by the price of natural gas.

4.3.1.1 Natural Gas Price Forecast Explanation

Natural gas prices have a history of volatility as evidenced by the experience of the last 10 years. On an annual average basis from 1997 to 2007 the price ranged from US$1.52 to US$6.76 with an annual average price of US$4.76 and a standard deviation of $1.88 (all in nominal US dollars). Mid-2008 spot prices were near or at an all-time high (C$11.00 per GJ for the month of June 2008 for example), while

[51] WECC, 2006. WECC 10-Year Coordinated Plan Summary – July 2006, Figure 3.

current prices (April 2009) are significantly lower. Long-term forecasts tend to be influenced by current spot prices, which suggest that mid-2008 pricing will tend to push longer term price forecasts up. The same rationale suggests that lower "current" gas prices will push longer term forecasts down. In short, natural gas prices are unpredictable, causing material variations in the forecasts developed from them, and therefore, depending upon the price of the day, natural gas price forecasts could be viewed as low or high. Taking the above into account, FortisBC considers that the Energy Information Administration's most recent forecast reflects a reasonable approach to forecasting longer term natural gas prices.

4.3.2 Electricity Price Forecast

For the purposes of this 2009 Resource Plan, FortisBC adopted the BC Hydro 2008 LTAP Mid-range Forecast.[52] BC Hydro's forecast was recently tested in the BC Hydro 2008 LTAP process before the Commission and is, in FortisBC's view, a reasonable estimate of future wholesale electricity market prices.

To this forecast number is added a transmission cost[53] to approximate the cost of moving the power to FortisBC's load, as well as a greenhouse gas cost that has, in the absence of any other formalized cost structure, been calculated based upon the carbon tax contemplated by the Carbon Tax Act. Table 4.3.2, below sets out the forecast electricity price from the wholesale market.

[52] Willis Energy Services Ltd. derived the BC Hydro 2008 LTAP Mid-range Forecast from BC Hydro's graphical presentation in Figure 4.6 of the BC Hydro 2008 LTAP, and then adjusted it to C$2009 for FortisBC.

[53] The transmission cost adder is inclusive of line losses, tariff and scheduling fees, and ancillary services as applicable.

Table 4.3.2: FortisBC Wholesale Market Electricity Price Forecast

Year	1. BCH 2008 LTAP Mid Forecast (2009 Real C$/MWh)	2. Transmission Adder-- Wholesale Market ($/MWh)	3. Transmission Loss Adjustment (6.9%)	4. GHG Adder $/MWh (equivilent to BC Carbon Tax)	FortisBC Price Forecast $/MWh (1+2+3+4)
2009	$50.39	$6.45	$3.48	$4.40	$64.71
2010	$50.91	$6.45	$3.51	$6.03	$66.91
2011	$44.09	$6.45	$3.04	$7.61	$61.18
2012	$39.89	$6.45	$2.75	$9.11	$58.20
2013	$43.56	$6.45	$3.01	$9.74	$62.76
2014	$46.19	$6.45	$3.19	$9.74	$65.57
2015	$49.34	$6.45	$3.40	$9.74	$68.93
2016	$49.34	$6.45	$3.40	$9.74	$68.93
2017	$46.71	$6.45	$3.22	$9.74	$66.13
2018	$48.81	$6.45	$3.37	$9.74	$68.37
2019	$50.39	$6.45	$3.48	$9.74	$70.06
2020	$54.58	$6.45	$3.77	$9.74	$74.54
2021	$58.78	$6.45	$4.06	$9.74	$79.03
2022	$58.78	$6.45	$4.06	$9.74	$79.03
2023	$59.83	$6.45	$4.13	$9.74	$80.16
2024	$60.88	$6.45	$4.20	$9.74	$81.28
2025	$60.88	$6.45	$4.20	$9.74	$81.28
2026	$62.98	$6.45	$4.35	$9.74	$83.52
2027	$64.03	$6.45	$4.42	$9.74	$84.64
2028	$65.08	$6.45	$4.49	$9.74	$85.77

4.4 Market Analysis Summary: Risks and Conclusions

4.4.1 Assessment of Potential Risks

4.4.1.1 Reliability Risk

FortisBC must be able to deliver safe, secure, reliable power to meet the Company's customer load. The Company currently relies upon the wholesale electricity market for a sizeable and growing portion of its load. In 2009, wholesale market-supplied capacity accounts for 145 MW, or 21% of forecast peak demand, which if not replaced with more secure resources, will grow to 239 MW (after DSM), or 30% of forecast demand in 2028.

In light of wholesale electricity market availability constraints and the pricing forecast set out above, FortisBC believes it cannot responsibly expect to rely on the wholesale electricity market to provide an economic, predictable and reliable supply over the planning period of this 2009 Resource Plan. As the Willis Electricity Market Report concludes, "Transmission constraints in the region are going to become

more serious as margins in the region diminish. Purchasing capacity from other utilities on a long-term basis is going to become increasingly more difficult."

FortisBC's Assessment: increasing reliability risk

- Transmission constraints within the WECC region, as discussed in Section 3.8 above, bring into question the continued deliverability of power, whether available for sale or not.

- As discussed in Section 3.5.3.1 above, newly regulated renewable additions to the system contribute to making the continued availability of capacity questionable, since selling utilities will need to reserve capacity to support their intermittent renewable resources.

FortisBC concludes, therefore, that as load grows, reliability risk cannot be adequately dealt with by reliance upon the wholesale electricity market

4.4.1.2 Price Risk

FortisBC must be able to provide power in a cost effective manner that minimizes rate volatility.

FortisBC's existing policy has been a combination of spot, and short term energy and capacity purchases. This has proven to be a relatively successful strategy to this point, as favourable pricing has benefited ratepayers. However, as shown in Section 4.3.2 above, it is reasonable to expect that the price of electricity in the wholesale electricity market will trend upwards. Further, reliance upon the wholesale market carries price volatility risk in addition to supply reliability risk. The volatility of the spot wholesale electricity market is illustrated in Figure 4.1.1.1-A and 4.1.1.1-B. The risk is that at some point price spikes will sharply increase power purchase expenses. Further, the size of the risk is growing as FortisBC's reliance upon the wholesale market grows.

This volatility potential is exacerbated by the following facts:

- The Northwest Power Pool[54] area (including FortisBC) is a winter peaking area, utilizing predominately hydro-driven power generation. Hydro reservoirs are at their lowest during this time – reducing supply and increasing electricity costs.

- FortisBC's summer peak is growing, and has exceeded existing capacity. During the summer months, markets in the southern states (California for example) are also peaking, and market costs are typically driven up at this time.

[54] Northwest Power Pool is a subset of WECC representing the northwest and including British Columbia

The potential combined impact is that at some point the Company will be paying well above FortisBC's current cost structure.

FortisBC's Assessment: increasing price risk

- There is rate volatility in the wholesale electricity market.
- As market supply shrinks (relative to increasing demand), cost of electricity products will increase, negatively impacting FortisBC's power purchase costs.
- As FortisBC's dependence upon the market increases over time, the Company's overall electricity costs will become more market driven and less within its ability to control.

4.4.1.3 Divergence from BC Energy Plan

The BC Energy Plan, Policy Action 10, has the objective of ensuring provincial self-sufficiency to meet electricity needs, including "insurance" by 2016. Reliance upon the wholesale electricity market does not meet this policy directive. Given that the Company is forecasting growth in its load / resource gap, FortisBC expects it would become increasingly out of step with the provisions of Section 64.01(2) of the Act, and with the objective of Policy Action 10.

4.4.2 Conclusion

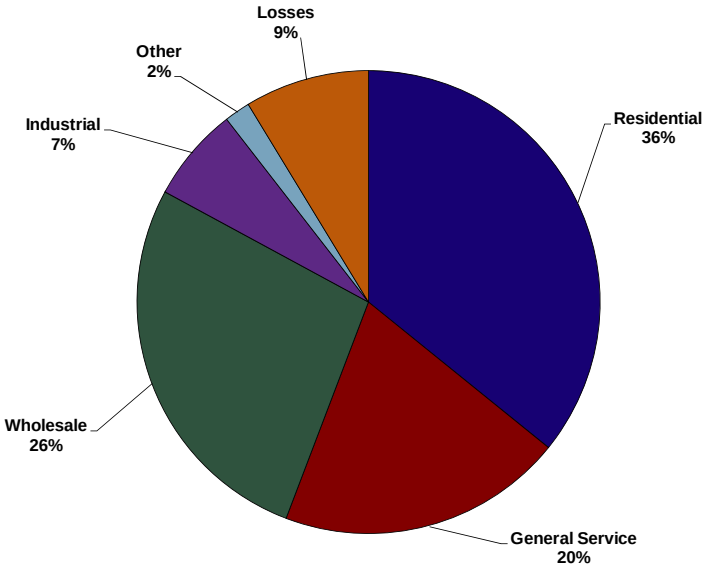
FortisBC's continued reliance upon the wholesale electricity market to meet current and future needs is not a prudent strategy. The market is volatile and the cost of purchases is expected to trend upward. Availability of capacity products, as well as transmission capability necessary to move the power to FortisBC's market, is in question. Finally, the Act requires each public utility, in its resource planning, to consider the government's goal that British Columbia be self-sufficient by 2016.

5 LOAD FORECAST

5.1 Load Breakdown

FortisBC's gross system energy load ("**gross load**") is the aggregate of residential, wholesale, general service, industrial, street lighting and irrigation loads, including system losses and Company use. The residential, general service and wholesale loads together represent 83% of FortisBC's 2009 forecast gross load. These three load classes are strongly correlated to population levels in FortisBC's service area. In 2009, industrial load percentage of gross load has dropped from its historical 10% to less than 7%, mainly due to economic depression in the forestry industry. For 2009 gross system losses are forecast at 8.7%. FortisBC's 2009 distribution of forecast gross load is shown by customer class in Figure 5.1 below.

Figure 5.1: Forecast Gross Load by Customer Class, 2009



5.1.1 Customer Sectors

Residential

FortisBC's residential customer growth forecast is initially based on a review of past customer additions. The number of residential customers FortisBC directly serves has continued to increase steadily, rising from 78,008 in 2000 to 95,502 in 2008. Annual energy requirements for the residential class have increased from 987 GWh in 2000 to 1,221 GWh in 2008.

FortisBC forecasts customer growth using population projections produced by BC STATS (Population Section, Ministry of Labour and Citizens' Services) ("**BC STATS**"). An average, weather-normalized use-

per-customer value is calculated and then multiplied by the projected number of accounts to obtain annual energy sales over the forecast period. An average annual growth rate of about 1.2% from 2009 to 2028 will see the number of FortisBC residential customers increase to 120,118 by 2028. On this basis, FortisBC forecasts its annual Residential energy requirements will be 1,515 GWh by 2028.

General Service

This class of customers is broad, encompassing a range of sub-classes that include finance, insurance and real estate services, wholesale and retail trade, community business and personal services, public administration, transportation, communication and other miscellaneous commercial sector customers. General Service category annual energy sales have increased from 498 GWh in 2000 to 666 GWh in 2008. FortisBC forecasts its General Service annual energy requirements will be 976 GWh by 2028.

Industrial

Forestry, pulp and sundry comprise over one-third of FortisBC's industrial customers. Other classes of customers include educational institutions, growers, construction, manufacturing and mining. Where possible, FortisBC obtains electricity use and forecast energy demand information directly from individual industrial customers. Industrial loads have varied significantly in the last several years due to the downturn in the forestry industry. FortisBC forecasts its annual Industrial energy requirements will be 296 GWh by 2028.

Wholesale

FortisBC sells wholesale power to municipalities within its service area that own and operate their own electrical distribution systems, and to BC Hydro at Lardeau and Kingsgate. The municipal utilities are the cities of Grand Forks, Kelowna, Nelson, Penticton and the District of Summerland. FortisBC forecasts its annual Wholesale energy requirements will be 1,060 GWh by 2028.

Irrigation and Lighting

Irrigation demands are a function of acreage planted, type of crop planted and local weather. Owing to variability in these factors and the challenges in forecasting, FortisBC forecasts (flat) annual energy sales of 48 GWh throughout the planning period of this 2009 Resource Plan.

For Lighting FortisBC assumes that gains in lighting efficiency will generally offset increased demands from fixture additions. The Company forecasts that annual lighting loads will remain constant at 13 GWh throughout the planning period of this 2009 Resource Plan.

System Losses

FortisBC system losses consist of:

1. transmission and distribution line losses and transformation losses;

2. losses on wheeling through the BC Hydro system;
3. Company use; and
4. unaccounted for energy (such as metering inaccuracies or theft).

Average system losses from 2000 to 2008 were 10% of the gross load. Since 2005 FortisBC has implemented a number of transmission system improvements. Gross system losses for 2008 are reported at 9.2% (comparing gross system load with billed energy).

5.2 Energy Forecast

The load on FortisBC's system is expected to grow from 3,426 GWh in 2009 to 4,278 GWh in 2028, an average annual energy growth rate over the planning period of this 2009 Resource Plan of approximately 1.2%. As described in detail in Section 5.1 above, FortisBC expects growth for each of the residential, general service, wholesale, and industrial customer classes, while it expects lighting and irrigation energy requirements to remain constant. Figure 5.2 below depicts this forecast over the planning period of this 2009 Resource Plan.

This forecast does not take into consideration the impact of Demand Side Management activities, as DSM is considered a resource for meeting load growth. Discussion about DSM's contribution to meeting load growth is set out in Section 6.1.4 below.

Figure 5.2: FortisBC Energy-Load Forecast by Sector (MWh)

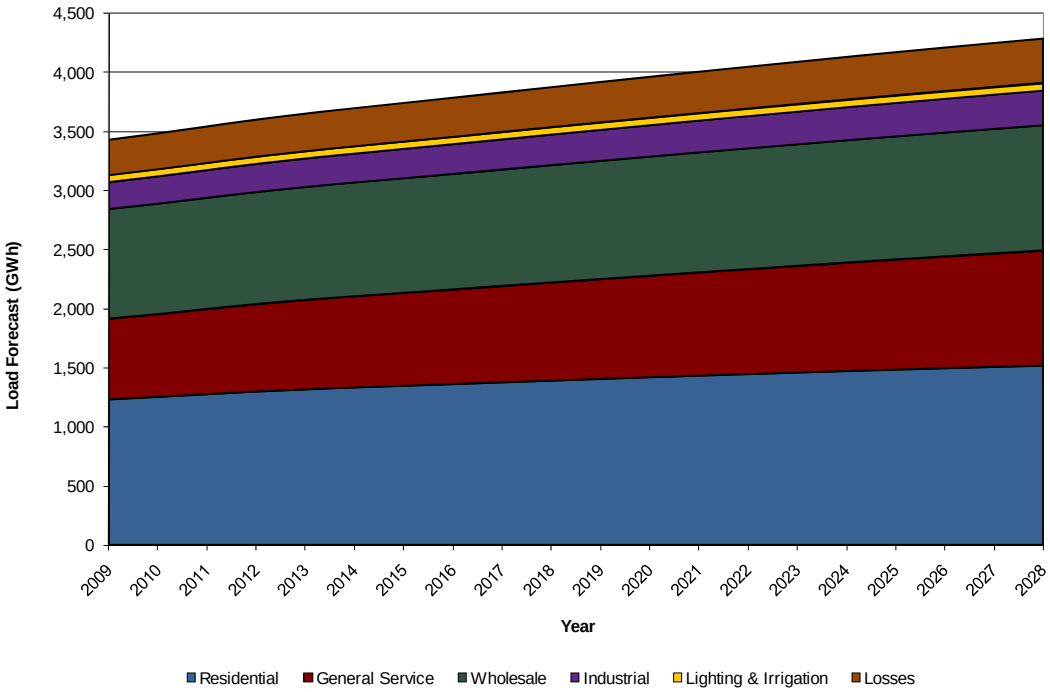


Table 5.2 below indicates the expected load growth over the forecast period, in percentage terms, by sector.

Table 5.2: FortisBC Energy Cumulative Sales Growth per Sector

	2009	2010	2015	2028
Residential	Base	4%	11%	23%
Commercial (General Service)	Base	6%	18%	40%
Industrial	Base	2%	10%	28%
Wholesale	Base	4%	8%	16%
Lighting and Irrigation	Base	0%	0%	0%
Total Net Load (not incl. Losses)	**Base**	**4%**	**11%**	**25%**

5.2.1 Energy Forecast Range

In order to account for inherent uncertainty in a load forecast, FortisBC (like BC Hydro and other utilities) has developed high and low forecast scenarios based on a Monte Carlo analysis.[55] This approach is

[55] A Monte Carlo analysis is a statistical approach that estimates a probability range by combining the probability of a number of variables that are the key forecast variables to a forecast determination.

consistent with the Commission's recommendation in its Reasons for Decision regarding the 2005 Resource Plan issued concurrently with Order 9-52-05. Further detail on the Monte Carlo analysis, including key forecast variables, is contained in Appendix F.

Figure 5.2.1 below indicates the forecast range that FortisBC has developed using the Monte Carlo simulation. The area banded by the high and low forecasts represents, with a 90% probability, the range within which the actual load will be. There is a 5% probability that the actual load will be above the high forecast, and a 5% probability that the actual load will be below the low forecast.

Figure 5.2.1: FortisBC Gross Load Forecast

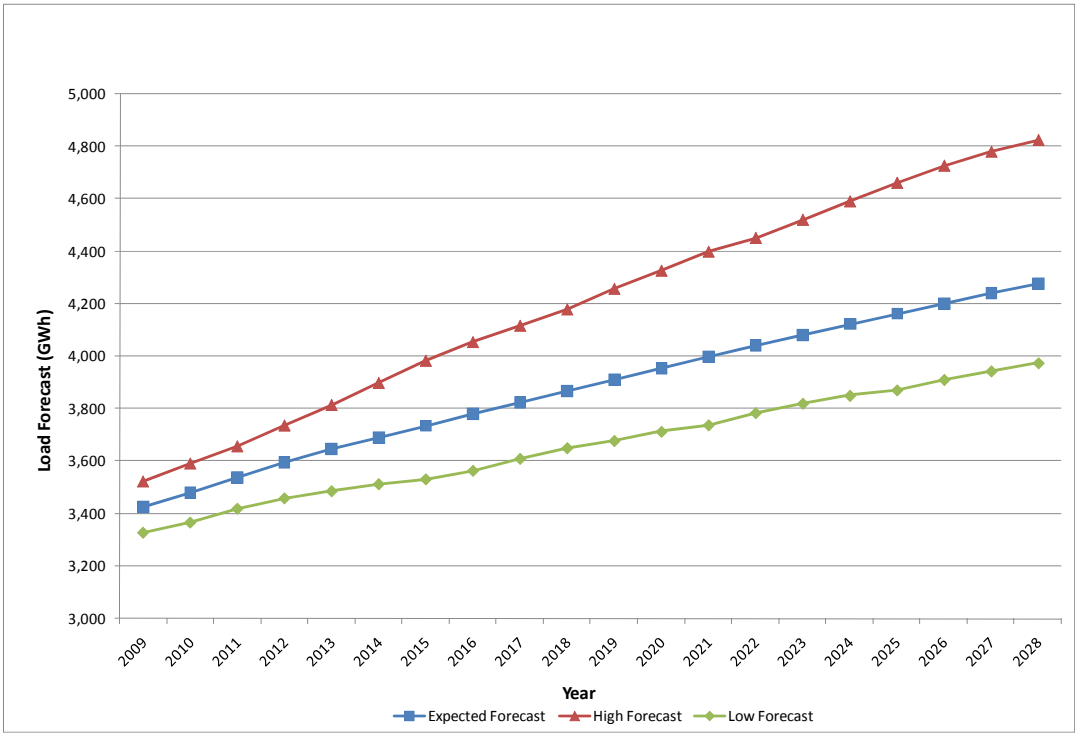


Table 5.2.1 below provides the same information in tabular form.

Table 5.2.1: FortisBC Energy Forecast (GWh)

Year	Low Forecast	Expected Forecast	High Forecast
2009	3,329	3,426	3,524
2010	3,367	3,480	3,592
2011	3,420	3,538	3,657
2012	3,460	3,596	3,737
2013	3,487	3,647	3,815
2014	3,514	3,691	3,899
2015	3,532	3,736	3,984
2016	3,565	3,781	4,055
2017	3,610	3,825	4,117
2018	3,651	3,869	4,179
2019	3,678	3,913	4,258
2020	3,713	3,956	4,327
2021	3,738	3,999	4,400
2022	3,785	4,041	4,453
2023	3,820	4,083	4,522
2024	3,851	4,123	4,592
2025	3,872	4,163	4,662
2026	3,911	4,203	4,728
2027	3,944	4,241	4,781
2028	3,975	4,278	4,826

5.3 Forecast Peak Demand

Peak Demand growth is dependent upon load growth and temperature conditions in any given year. For FortisBC, as a winter peaking utility, the coldest period during the winter, as opposed to the hottest period in the summer, determines the highest annual peak.

FortisBC's peak demand forecast is based upon historical peak averages. This approach assumes that the average temperatures which have occurred over the last 10 years ("normal" weather) will recur over the next 20 years. A result of this approach is that it does not accommodate weather generated excursions from the forecast. (FortisBC experienced such an excursion in December 2008. FortisBC's December 2008 peak forecast was 673 MW, while the actual peak was 746 MW – a difference of 11%). Over the last 10 years (1998 – 2008) the monthly actual peak has been higher than forecast 46.7% of the time, by an average 36 MW (or 6%), with the maximum difference being 118 MW, or 19.3% in November 2006. In order to partially mitigate the risk of extreme weather, FortisBC also prepares a forecast of seasonal peaks. The winter season peak is the peak experienced in any of November, December, January or February. The summer season peak is the peak experienced in either July or August.

The monthly peak forecast results are shown in Table 5.3 below, following, including, for the months of January and July the seasonal peak forecast.

Further detail on the forecasting process is contained in Appendix F.

Table 5.3: Peak Demand Base Forecast (MW)

	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Peak
2009	701	600	550	492	455	495	560	538	454	519	613	666	701
2010	712	609	559	500	462	502	568	547	461	527	622	676	712
2011	724	619	568	508	470	511	578	556	468	536	632	687	724
2012	736	630	578	516	478	519	587	565	476	545	643	699	736
2013	746	639	586	524	485	527	596	573	483	553	652	709	746
2014	755	646	593	530	491	533	603	580	489	559	660	717	755
2015	764	654	600	537	497	539	610	587	495	566	668	726	764
2016	774	662	607	543	503	546	618	594	501	573	676	735	774
2017	783	670	615	549	508	552	625	601	507	580	684	743	783
2018	792	678	622	556	514	559	632	608	513	586	692	752	792
2019	801	685	629	562	520	565	640	615	518	593	700	760	801
2020	810	693	636	568	526	571	647	622	524	600	707	769	810
2021	819	700	643	575	532	578	654	629	530	606	715	777	819
2022	827	708	650	581	537	584	661	635	536	613	723	786	827
2023	836	715	656	587	543	590	667	642	541	619	730	794	836
2024	844	722	663	593	548	596	674	648	547	625	738	802	844
2025	852	729	669	598	554	602	681	655	552	631	745	810	852
2026	860	736	676	604	559	607	687	661	557	637	752	817	860
2027	868	743	682	610	564	613	694	667	562	643	759	825	868
2028	876	750	688	615	569	618	700	673	567	649	766	832	876

The blue highlighting on Table 5.3 indicates when forecast peak demand exceeds FortisBC's existing capacity resources. The forecast data in Table 5.3 illustrates that FortisBC's existing capacity is exceeded in eight months of the year by 2013, and ten months of the year by 2026.

5.3.1 Peak Demand Forecast Range

The Monte Carlo simulation for the energy load forecast developed a forecast range for the energy load over the planning period of this 2009 Resource Plan. This same forecast range was applied to the peak demand forecast. This forecast range is expressed in graphical and tabular form below.

Figure 5.3.1-A: FortisBC Peak Demand Forecast

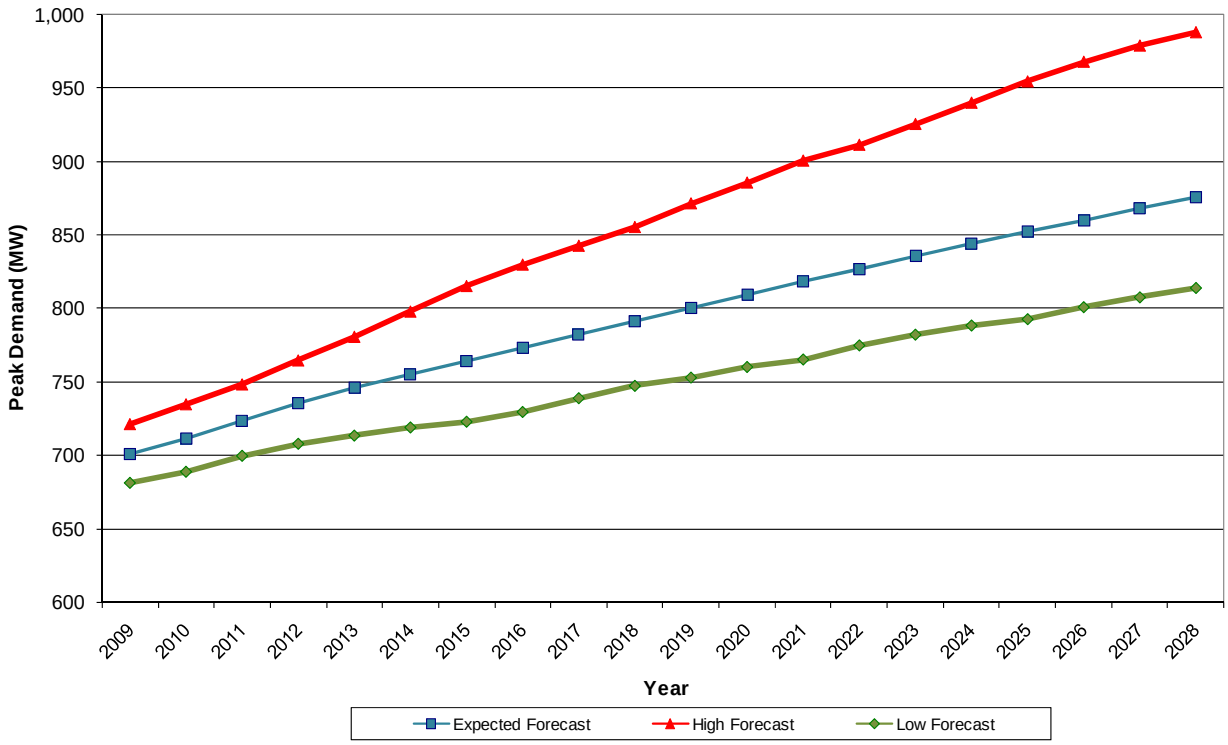


Table 5.3.1: FortisBC Annual Peak Demand Forecast (MW)

Year	Low Forecast	Expected Forecast	High Forecast
2009	681	701	721
2010	689	712	735
2011	699	724	748
2012	708	736	764
2013	713	746	780
2014	719	755	798
2015	723	764	815
2016	729	774	830
2017	739	783	843
2018	747	792	855
2019	753	801	871
2020	760	810	886
2021	765	819	901
2022	775	827	911
2023	782	836	926
2024	788	844	940
2025	793	852	955
2026	801	860	968
2027	808	868	979
2028	814	876	988

Forecast growth over the planning period of this 2009 Resource Plan is 25%, with the “expected” forecast peak being 876 MW in 2028. The 2028 “high” peak demand forecast is 988 MW and the 2028 “low” peak demand forecast is 814 MW.

By 2013, FortisBC’s capability to be self-sufficient and to provide secure, reliable power production, without reliance upon the wholesale electricity market, will be in question no less than eight months of the year.

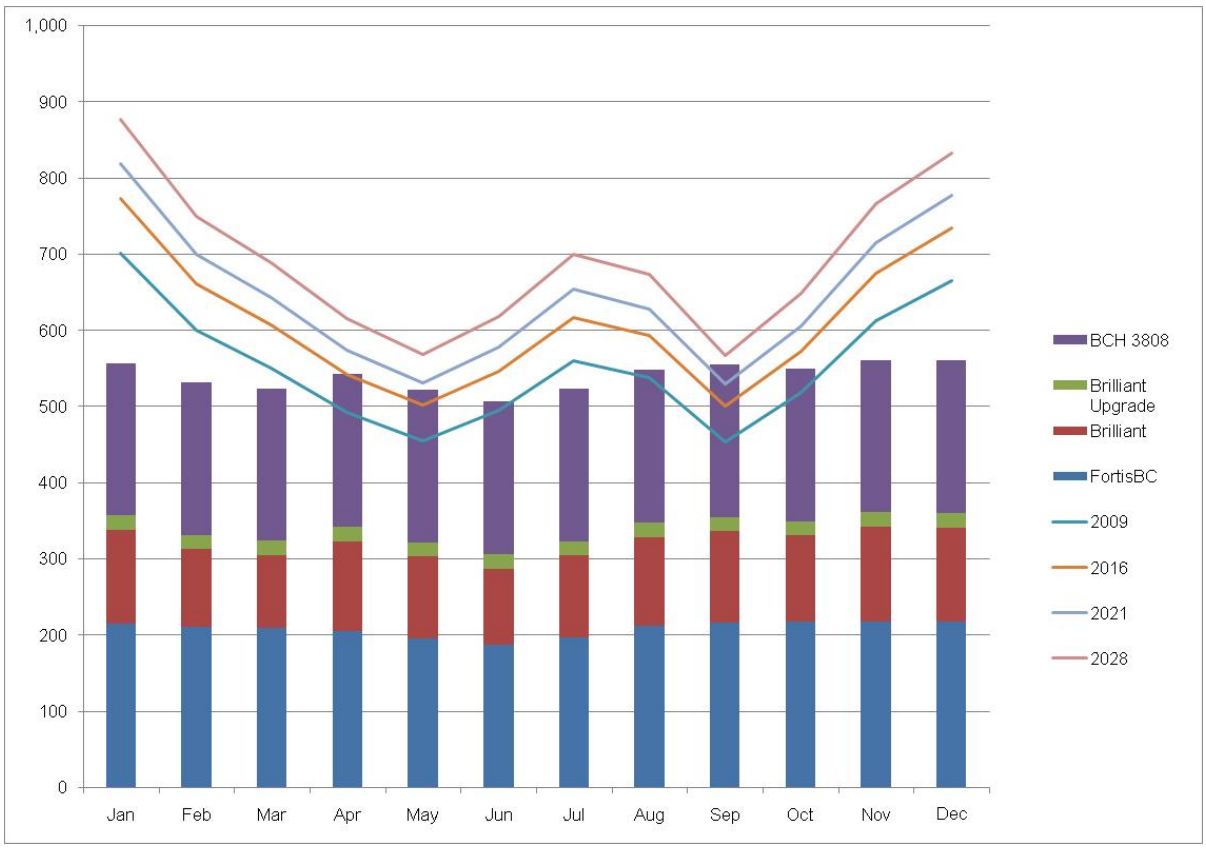
5.3.2 Monthly Capacity

The FortisBC Plants have an installed capacity of 223 MW, which, along with the BC Hydro PPA and the Brilliant PPA, constitute the Company’s existing firm capacity resources. The Company’s actual peak capacity, however, is largely a function of the capacity Entitlements determined pursuant to the Canal Plant Agreement. On this basis, the peak capacity for all of the Company’s existing resources (excluding the BC Hydro PPA) is different for each month of the year. For example:

- Long Term, Firm Capacity in January equals 552 MW
- Long Term, Firm Capacity in July equals 514 MW

Figure 5.3.2 below graphically describes the growing monthly gap between peak demand and available resources. The bars represent available resources (excluding DSM), and the lines represent forecast peak demand, by month, for the years 2008, 2015, 2020, and 2027. This figure illustrates the need for capacity resources that can flexibly meet the Company's differing monthly peak capacity requirements.

Figure 5.3.2: Monthly Peak Capacity: Current & Forecast



5.3.3 Forecast Sensitivity

As stated in Appendix F, the key variable for the FortisBC forecast is the population forecast, which the Company obtained from BC STATS. FortisBC varied this base forecast in a Monte Carlo simulation as set out in Section 1.1.2, Table 4 of Appendix F. Specifically, FortisBC varied the following inputs in order to provide a range of probabilities to produce the expected, high and low forecasts used in this 2009 Resource Plan:

- population growth;
- relationship of residential customers to population;
- relationship of general service customers to population;
- relationship of wholesale load to population;
- industrial load growth
- residential use per customer; and
- general service use per customer.

Section 1.1.2 of Appendix F also notes a number of factors that are not direct inputs to the load forecast but are captured in the sensitivity analysis by way of varying the inputs listed above. These factors include growth in Gross Domestic Product, energy price elasticity, environmental requirements, new technology, new electricity uses and/or changing lifestyle factors. These variables could impact FortisBC's load forecast, depending upon how and when they mature. To illustrate the uncertainty associated with these variables, a summary of the potential impact of the Plug-In Hybrid Electric Vehicle ("**PHEV**") (being a "new electricity use") is set out below.

FortisBC understands that many if not most auto manufacturers are aiming at producing some variant of a PHEV. Mass roll-out of these vehicles appears to be currently constrained by numerous factors, including:

- progress in the research and development on various vehicle components;
- consumer adoption of existing variants is slow; and
- there are few charging stations installed for consumer use.

In July 2008 the Electric Power Research Institute announced a research-and-development collaboration with General Motors and 34 Canadian and U.S. utilities, including BC Hydro, Manitoba Hydro and Hydro Quebec, to facilitate integration of PHEVs into the grid. The collaboration will work to accelerate large-scale deployment of PHEVs and create a blueprint for an electric-fuel infrastructure. The supplanting of fossil fueled vehicles with PHEVs, when and if it happens, could have a major impact upon utility loads – presuming the new load is not offset by other variables such as lifestyle changes. While, to FortisBC's knowledge, no empirical projections of the potential impact of PHEVs specific to the British Columbia or FortisBC markets have been located, it is reasonable to expect some impact.

Therefore, while it remains too early to tell what impact these factors may have on FortisBC's load forecast, it is important for FortisBC to make resource decisions that retain sufficient flexibility to accommodate these potential impacts. FortisBC is monitoring developments and will continue to do so. As these potential impacts become more definitive they will be integrated into FortisBC's load forecast and its future resource planning.

6 RESOURCE REQUIREMENTS

6.1 Existing Resources

6.1.1 FortisBC-Owned Resources

FortisBC owns the Corra Linn, Upper Bonnington, Lower Bonnington and South Slocan generating plants (collectively, the "**FortisBC Plants**") located on the Kootenay River between Nelson and Castlegar, British Columbia. In 2008 the FortisBC Plants supplied about 47% of FortisBC's energy requirements and about 30% of the Company's peak demand.

FortisBC operates the FortisBC Plants in accordance with the Canal Plant Agreement, which is an agreement among BC Hydro, FortisBC, Teck, Brilliant Power Corporation, Brilliant Expansion Power Corporation and Waneta Expansion Power Corporation made as of the 1st day of July, 2005 (the "**Canal Plant Agreement**"). (FortisBC, Brilliant Power Corporation, Teck, Brilliant Expansion Power Corporation and Waneta Expansion Power Corporation are collectively defined in the Canal Plant Agreement as the "**Entitlement Parties**".) The Canal Plant Agreement enables BC Hydro and the Entitlement Parties, through coordinated use of water flows and storage reservoirs and through coordinated operation of generating plants, to generate more power from their respective generating resources than they could if they operated independently. Under the Canal Plant Agreement, BC Hydro takes into its system all power actually generated by the Entitlement Parties' plants. In exchange for permitting BC Hydro to determine the output of these facilities, the Entitlement Parties are contractually entitled to their respective "Entitlements" of capacity and energy from BC Hydro. The Entitlement Parties receive their Entitlements irrespective of actual water flows to the Entitlement Parties' generating plants, and are, thus, insulated from the hydrology risk of water availability.

FortisBC is currently implementing an Upgrade and Life Extension Program (the "**ULE Program**") in respect of the FortisBC Plants. The ULE Program is an ongoing maintenance and refurbishment program designed to extend the useful production life of 11 of the 15 generating units in the FortisBC Plants. To date, the maintenance and refurbishment work on 8 of the 11 units has been completed. The work on the other 3 units is scheduled to be complete by 2011. The 11 generating units which are the subject of the ULE Program collectively represent approximately 89% of the capacity Entitlement of the FortisBC Plants under the Canal Plant Agreement. When complete, the ULE Program will assure power production at the FortisBC Plants through the planning period of this 2009 Resource Plan.

The remaining 4 generating units, all of which are installed at the Upper Bonnington Plant, provide the remaining 11% of the capacity Entitlement of the FortisBC Plants under the Canal Plant Agreement. These units are now due for refurbishment or replacement. FortisBC is currently studying the optimal

method of ensuring that these units continue to contribute to the Company's existing generation resources.

6.1.2 Long Term Contractual Resources

6.1.2.1 BC Hydro Power Purchase Agreement

As noted above in Section 3.3.2, FortisBC is party to the BC Hydro PPA. The BC Hydro PPA provides the Company with electricity for the purpose of supplying FortisBC's load requirements, up to a maximum demand of 200 MW of capacity. FortisBC makes purchases under the BC Hydro PPA at Commission-approved tariffs. Currently, the cost of energy under the BC Hydro PPA is $31.14 per MW hour and the cost of capacity is $5,313.00 per MW per month.

The BC Hydro PPA represents an important resource for FortisBC, providing in 2008 approximately 27% of FortisBC's capacity needs and approximately 24% of its energy needs.

6.1.2.2 Proposed Renewal of BC Hydro PPA

The current term of the BC Hydro PPA expires in 2013. For more than three years FortisBC and BC Hydro have been engaged in negotiations to renew the BC Hydro PPA. Those negotiations have not, to date, resulted in agreement on terms satisfactory to both parties. In fact, FortisBC is not encouraged by the most recent exchange of correspondence between the parties, and does not believe that any such agreement is imminent. Nevertheless, for the purposes of this 2009 Resource Plan, FortisBC has assumed that the BC Hydro PPA will be renewed, on substantially the same terms and conditions (except as described in Sections 6.1.2.2.1 and 6.1.2.2.2 below), for an additional term that will extend at least to the end of the planning period of this 2009 Resource Plan.

Two issues in respect of which FortisBC has sought (and continues to seek) to negotiate a change to the terms of the (renewed) BC Hydro PPA are described in Sections 6.1.2.2.1 and 6.1.2.2.2 immediately below.

6.1.2.2.1 200 MW of Firm Capacity

In connection with the BC Energy Plan, certain of BC Hydro's generation assets have been designated as "heritage assets" providing a secure, reliable supply of low-cost power for all British Columbians. BC Hydro's "heritage assets" are to be operated pursuant to a Heritage Contract, the purpose of which is described in the BC Energy Plan as follows:

> BC Hydro owns the heritage assets, which include historic electricity facilities such as those on the Peace and Columbia Rivers that provide a secure, reliable supply of low-cost power for British Columbians.
>
> ….
>
> Under the 2002 Energy Plan, a legislated heritage contract was established for an initial term of 10 years to ensure BC Hydro customers benefit from its existing low-cost resources. With The BC Energy Plan, government confirms the heritage contract in perpetuity to ensure ratepayers will continue to receive the benefits of this low-cost electricity for generations to come.[56]

The discussion expanding on Policy Action 16 of the BC Energy Plan describes more specifically the nature of the low-cost benefit that BC Hydro's customers are meant to enjoy by virtue of the operation of the Heritage Contract, in the following language:

> The Heritage Contract ensures BC Hydro ratepayers receive heritage power that are (sic) based on costs of generation, not market prices. [57]

The BC Energy Plan goes on to confirm that the benefits of the Heritage Contract are intended to be extended to BC Hydro's customers in perpetuity:

> The Heritage Contract includes a provision stating the Contract may be terminated with 5 years notice if notice is given any time after April 1, 2009. While no official 'end date' to the Heritage Contract exists, the language of the contract implies the potential for termination and thus creates uncertainty. Government will re-affirm and strengthen its commitment to the Heritage Contract though amendments addressing this uncertainty.[58]

As a customer of BC Hydro, FortisBC believes it and its ratepayers are entitled to the benefit of the Heritage Contract. On the basis that it is so entitled, FortisBC is seeking to negotiate inclusion in the renewed BC Hydro PPA of an acknowledgement of FortisBC's right to receive 200 MW of firm capacity and all associated energy at embedded cost rates.

6.1.2.2.2 Relaxation of Export Restriction

The BC Hydro PPA currently precludes the export of power by FortisBC during any hour in which it is taking energy from BC Hydro under the BC Hydro PPA[59]. This export restriction makes the development

[56] BC Energy Plan, p. 12

[57] BC Energy Plan, Policy Action 16, Electricity Policies, p. 4

[58] BC Energy Plan, Policy Action 16, Electricity Policies, p. 4

[59] BC Hydro PPA, section 8.9

or acquisition by FortisBC of new resources (whether through development of new generation facilities, entering into long-term power purchase agreements, or acquiring other alternative forms of supply) uneconomic, since power provided by such new resources would, for the majority of hours, displace the (generally low-cost) supplies of power available under the BC Hydro PPA. This dynamic is at odds with FortisBC's overall responsibility to obtain cost-effective and secure long-term sources of supply.

Moreover, in order to maintain the cost-effectiveness of any acquired new resources, FortisBC needs to be able to dispose of surplus power produced by such resources while ensuring that low-cost power under the BC Hydro PPA continues to be available to its customers. However, the export restriction in the BC Hydro PPA prevents FortisBC from economically disposing of surplus power from new resources.

Accordingly, FortisBC is seeking to negotiate exclusion from the renewed BC Hydro PPA of the existing export restriction insofar as it would apply to new resources. This change would make it possible for FortisBC to fulfill its obligation to meet incremental load-growth requirements apart from the BC Hydro PPA.

6.1.2.2.3 Implications for 2009 Resource Plan

If, upon renewal of the BC Hydro PPA, the supply of energy associated with a firm 200 MW of capacity were to be reduced, or if FortisBC were unable to secure renewal of the BC Hydro PPA on satisfactory terms, then the energy available to meet FortisBC's demand requirements would accordingly be reduced. FortisBC's current energy supply deficit would increase commensurately. Each of the new resource portfolios proposed in Section 7 of this 2009 Resource Plan would have to be adjusted accordingly — with a corresponding resulting increase in cost to FortisBC ratepayers — to accommodate this change.

In addition, if the 200 MW of capacity that BC Hydro is obliged to supply to FortisBC is not firm then, apart from all other considerations, FortisBC would require an additional 10 MW of Planning Margin above the 45 MW proposed in Section 6.3.1.1 of this 2009 Resource Plan. That is because the Company's Planning Margin requirement is calculated without regard to the 200 MW of capacity under the BC Hydro PPA, which FortisBC assumes to be firm and, therefore, not requiring Planning Margin back-up.

6.1.2.3 Brilliant Power Purchase Agreement

FortisBC is party to a power purchase agreement with Brilliant Power Corporation made as of the 4th day of April, 1996 (the "**Brilliant PPA**"). Under the Brilliant PPA, which expires in 2056, FortisBC has agreed to purchase (a) the energy and capacity Entitlement allocated to the Brilliant Plant pursuant to the Canal Plant Agreement and (b) after the expiration of the Canal Plant Agreement (which is terminable upon 5 years' notice given any time after December 31, 2030), the actual electrical output generated by the Brilliant plant. The Brilliant PPA uses a take-or-pay structure which requires that FortisBC pay for the

Brilliant plant's Entitlement, irrespective of whether FortisBC actually takes it. During the first 30 years of the term of the Brilliant PPA, FortisBC pays to Brilliant Power Corporation, in fixed monthly payments, an amount that covers the operation and maintenance costs of the Brilliant plant, together with a return on capital including original purchase costs, sustaining capital costs and any life extension investments. In 2008, such costs were $33.13 / MWh. During the second 30 years of the term of the Brilliant PPA, amounts payable by FortisBC will be adjusted using a market price mechanism based on the depreciated value of the Brilliant plant and then-prevailing operating costs.

The Brilliant PPA provided approximately 17% of FortisBC's capacity requirements and 25% of its energy requirements in 2008.

6.1.2.4 Second Amendment of Brilliant PPA (Upgrade Amendment)

An amendment to the Brilliant PPA made in May of 1996 provides for an additional 65 GWh of energy and 20 MW of capacity until 2056. It was priced at $24.89 / MWh in 2008. After the first 30 years (ending in 2026), the pricing mechanism will be the same as that set out in the Brilliant PPA.

This amendment provided approximately 3% of FortisBC's capacity requirements and 1% of its energy requirements in 2008.

6.1.3 Wholesale Market Resources

Collectively, the FortisBC Plants, the BC Hydro PPA and the Brilliant PPA provided, in 2008, about 99% of the Company's energy requirements, but only about 76% of its peak capacity requirements. The capacity gap represents those hours during the year in which peak demand exceeds the Company's existing resources. FortisBC must address at least part of the capacity shortfall by making purchases in the short-term and spot wholesale electricity markets. The details of FortisBC's activities in those markets, and the risks associated with the Company's dependence on the wholesale electricity market, are discussed in detail in Section 4 and Appendix E of this 2009 Resource Plan.

6.1.4 Demand Side Management "Resources"

6.1.4.1 Relevant Utilities Commission Act provisions

Section 44.1(2)(f) of the Act obliges a utility, in any long-term resource plan prepared by it, to explain why the energy and capacity proposed to be acquired from planned facility additions or increased purchases is not instead planned to be replaced by "demand-side measures". The Act defines a "demand-side measure" to mean "a rate, measure, action or program undertaken (a) to conserve energy or promote

energy efficiency, (b) to reduce the energy demand a public utility must serve, or (c) to shift the use of energy to periods of lower demand[60].

6.1.4.2 Purpose of Demand Side Management

The general purpose of demand side management ("**DSM**") is to modify electricity consumption patterns in a manner that reduces electricity consumption in total or at specific times. The reduction of total energy use is referred to as "Energy Efficiency", or simply, "Conservation". The reduction of consumption at specific times in order to reduce peak capacity demand is generally referred to as "Demand Reduction", and is used to avoid high cost power at peak times, or to protect the electric grid from overloading.

As noted above in Section 6.1.3, FortisBC is a capacity constrained utility. Accordingly, this 2009 Resource Plan is to a large measure focused on meeting FortisBC's forecast capacity shortfalls. Although the DSM activities that have been described in this 2009 Resource Plan are largely energy-focused, there are nevertheless associated capacity reductions resulting from proposed DSM activities. In this 2009 Resource Plan, FortisBC has applied these Demand Reductions as the first resource solution, and the Company's preferred resource strategy described in Section 8 of this 2009 Resource Plan provides the balance of the required solution.

6.1.4.3 DSM-related portions of BC Energy Plan

The BC Energy Plan highlights the importance of DSM as a key component of future electricity supply. The Energy Plan Policy Actions that specifically address DSM programs are as follows:

- Policy Action 1 – Set an ambitious conservation target, to acquire 50 per cent of BC Hydro's incremental resource needs through conservation by 2020.
- Policy Action 2 – Ensure a coordinated approach to conservation and efficiency is actively pursued in British Columbia.
- Policy Action 3 – Encourage utilities to pursue cost effective and competitive demand side management opportunities.
- Policy Action 4 – Explore with BC utilities new rate structures that encourage energy efficiency and conservation.

[60] Act, Section 1, definition of "demand side measures"

6.1.4.4 FortisBC's DSM Target

FortisBC has actively been engaged in DSM through its PowerSense Program since 1989, offering assistance and efficiency measures to customers primarily through energy efficiency investments. PowerSense offers a number of programs within each of the residential, general service and industrial sectors. To date, the program measures have been selected to provide Conservation-based energy savings through improved energy use efficiency and energy use reduction.

The Company has implemented plans to accelerate realization of energy savings from existing DSM programs, to expand energy savings program offerings, and to investigate and offer appropriate and effective Demand Reduction programs with the objective of achieving the target set out in Policy Action 1 of the BC Energy Plan (relating expressly to BC Hydro) of meeting 50% of incremental resource needs through DSM measures by 2020 (the "**Energy Plan DSM Target**"). Meeting the Energy Plan DSM Target will require FortisBC to reduce by 50% the 553 GWh/year increase that FortisBC forecasts will have occurred by 2020. (It should be noted that this forecast is inclusive of existing levels of DSM activity). FortisBC's target, in the context of the Energy Plan DSM Target is, therefore, to achieve 277 GWh/year of additional, cumulative DSM savings by 2020.

FortisBC expects to achieve this target without taking into account energy savings that may be attributed to government-mandated codes and standards, price elasticity response, rate design impacts or energy savings incidental to Demand Reduction measures.

6.1.4.5 2008 – 2010 Planned Savings

In September 2005 the Company completed and filed with the Commission its "Efficiency Savings and Demand Reduction Potential" study. The study was input to the preparation of the Company's 2006 – 2010 Demand Side Management Business Plan (the "**2006-2010 DSM Business Plan**"), filed with the Commission in October 2005. The 2006-2010 DSM Business Plan provided the basis for the annual saving targets and planned expenditures FortisBC has included in its subsequent annual revenue requirements applications.

Table 6.1.4.5 below presents FortisBC's DSM targets for annual energy savings (GWh) and related demand reduction (MW) for the period from 2008 to 2010, based on expenditures for 2008 and the DSM budgets in FortisBC's 2009 – 2010 Capital Expenditure Plan, approved by Commission Order G-11-09.

Table 6.1.4.5: 2008 to 2010 Energy Efficiency (GWh) and Demand Reduction (MW) Estimates

2008 - 2010 Energy Efficiency Savings	2008 Actual	2009 Plan	2010 Plan	2008-10 Total
Residential	12.9	10.7	12.1	35.7
General Service	11.1	11.6	12.1	34.8
Industrial	3.3	3.0	3.4	9.6
Annual Savings (GWh)	**27.3**	**25.3**	**27.6**	**80.5**
Annual Demand Reduction (MW)	**5.4**	**4.7**	**5.1**	**15.2**

The energy savings plan figures set out in Table 6.1.4.5 above result from Conservation-based programs offered to customers in the residential, general service and industrial sectors. All DSM programs are available to FortisBC's customers, as well as those served by the Company's municipal wholesale customers.

6.1.4.6 2009 – 2010 Demand Side Management Expenditure Program

In response to the BC Energy Plan and the amendment of the Act to implement aspects of the BC Energy Plan, FortisBC requested in its 2009 – 2010 Capital Expenditure Plan for approval for a substantial (37.5%) increase in DSM funding as compared to 2008. The two-year plan savings of 52.8 GWh are expected to increase DSM to an estimated 31% of annual load growth.

The 2009-2010 Capital Expenditure Plan was approved by the Commission on February 27, 2009, and the approved DSM expenditures are summarized in Table 6.1.4.6 below.

Table 6.1.4.6: Demand Side Management Expenditures 2008-2010

	2008 Results			2009 Plan			2010 Plan		
	Cost ($000s)	Savings GWh	Savings MW	Cost ($000s)	Savings GWh	Savings MW	Cost ($000s)	Savings GWh	Savings MW
RESIDENTIAL									
2008 Base	1,222	12.9	2.7	1,023	8.4	1.7	1,023	8.4	2.0
Change to 2008 Base				(9)	0.7	0.3	107	2.1	0.3
New programs/incentives				377	1.6	0.3	386	1.6	0.3
Residential Total	*1,222*	*12.9*	*2.7*	1,391	*10.7*	*2.3*	1,516	*12.1*	*2.6*
GENERAL SERVICE									
2008 Base	880	11.0	1.4	754	9.1	1.7	754	9.1	1.7
Change to 2008 Base				98			188	0.5	0.1
New programs/incentives				436	2.5	0.5	438	2.5	0.5
General Service Total	*880*	*11.0*	*1.4*	*1,287*	*11.6*	*2.2*	*1,380*	*12.1*	*2.3*
INDUSTRIAL									
2008 Base	147	3.3	0.2	200	2.0	0.1	200	2.0	0.1
Change to 2008 Base				58	0.3	0.0	100	0.7	0.0
New programs/incentives				87	0.7	0.0	88	0.7	0.0
Industrial Total	*147*	*3.3*	*0.2*	*345*	*3.0*	*0.2*	*388*	*3.4*	*0.2*
TOTAL PROGRAMS									
2008 Base	2,249	27.3	4.2	1,977	19.5	3.5	1,977	19.5	3.8
Change to 2008 Base				147	1	0.3	395	3.3	0.4
New programs/incentives				899	5	0.9	912	4.8	0.9
Programs Total	**2,249**	**27.3**	**4.2**	**3,023**	**25.3**	**4.7**	**3,284**	**27.6**	**5.1**
Planning & Evaluation	419			503			519	0.0	
Conservation Culture				141			148	0.0	
ANNUAL TOTAL	**2,668**	**27.3**	**4.2**	**3,668**	**25.3**	**4.7**	**3,952**	**27.6**	**5.1**

This 37.5% increase in spending will augment the DSM programs FortisBC already offers through PowerSense, with initiatives that include the following:

- higher incentive levels for existing and/or new programs;
- new programs, such as support for solar hot water installations;
- increased residential home retrofit program take-up due to collaboration with the provincial LiveSmart BC program;
- increased general service savings as a result of the provincial Public Sector Energy Conservation (PSEC) Agreement, which will fund energy efficiency projects for public sector buildings;
- an increased focus on DSM services, including a small business energy audit program and industrial energy efficiency workshops; and

- a new emphasis on "Conservation Culture", which is a customer-focused behavioral change campaign.

FortisBC is a member of the BC Partnership for Energy Conservation & Efficiency Steering Committee. Through this Committee and its working group subcommittees, and through regular communication with other British Columbia public utilities, FortisBC ensures the PowerSense Program remains consistent with provincial goals.

6.1.4.7 Strategic DSM Report

In December 2008 the Company filed a Strategic Demand-Side Management Report (the "**Strategic DSM Report**"). The Strategic DSM Report, attached as Appendix I, reviews the primary drivers behind FortisBC's increased emphasis on DSM. In addition to meeting the requirements of the Act, and the BC Energy Plan discussed above in Section 6.1.4.4, the Strategic DSM Report outlines the following key drivers:

- customer expectations;
- FortisBC's capacity and energy deficit;
- price volatility in the wholesale electricity market; and
- technological change.

The Strategic DSM Report sets out and details 12 objectives that will guide development of FortisBC's DSM plan for the period from 2011 - 2020. The objectives are arrayed under the following sub-sections:

- Energy Plan Policy Actions;
- Legislative Requirements;
- Stakeholder Involvement;
- Valuation of Energy Efficiency and Demand Reduction Programs;
- Capacity Deficit;
- Monitoring & Evaluation Plans; and
- New Technologies.

6.1.4.8 The 2011 DSM Plan

FortisBC expects its DSM plan for the period from 2009 - 2010 to deliver increased energy efficiency results by the end of 2010. The Company intends to further enhance its DSM program initiatives in 2011 and beyond to meet the Energy Plan DSM Target and the requirements of the DSM Regulation. For this purpose the Company is preparing a 10-year DSM plan for the decade 2011-2020 (the **"2011 DSM Plan**"). FortisBC expects to file the 2011 DSM Plan in the second half of 2010. The 2011 DSM Plan will investigate both Energy Efficiency and Demand Reduction opportunities, marking the first time that

Demand Reduction will form a key component of FortisBC's DSM strategy. In addition the 2011 DSM Plan will study the potential effects of Conservation and Demand Reduction rate structures.

In summary, the 2011 DSM Plan will address the following areas:

- existing Energy Efficiency incentive program enhancements, building upon those already underway during 2009 and 2010;
- new Energy Efficiency and Demand Reduction incentive programs;
- new education and awareness programs focused on Energy Efficiency and Demand Reduction; and
- cost estimates and potential benefits of any further pilots or studies required to develop the 2011 DSM Plan.

In order to complete the above mandate, the 2011 DSM Plan will develop:

- a conservation potential study for each retail customer class;
- the estimated impact of codes and standards on load forecast;
- a long-term avoided cost of capacity for Demand Reduction and long-term avoided cost for Energy Efficiency;
- detailed business plans, with Energy Efficiency and Demand Reduction targets;
- preparation of business case analyses that set spending and investment levels sufficient to meet corporate and regulatory requirements;
- preliminary investigation and analysis of Demand Reduction options and technologies to develop estimates and define initiatives; and
- studies of the impact of time-of-use and dynamic pricing rates on Demand Reduction.

6.1.4.9 2008 – 2027 Projected Annual Savings

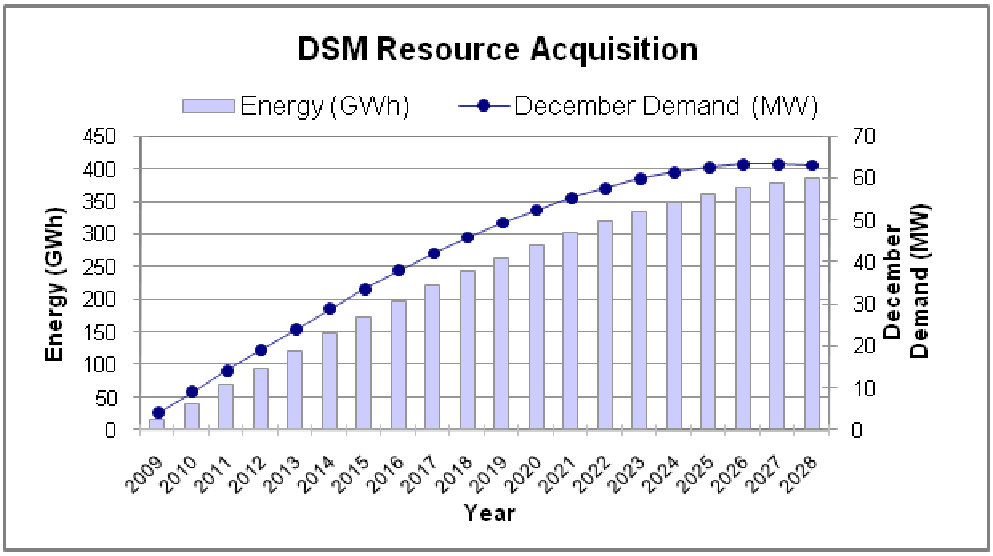
During the 2000 to 2007 period, realization of annual savings from FortisBC's DSM initiatives offset, on average, 25% of annual load growth for that same period. The Company's planned 2009-10 energy savings of 52.9 GWh are anticipated to offset approximately 31% of forecast annual load growth during that period. For the purposes of resource planning, FortisBC escalated the annual savings realization rate to meet 50% of cumulative load growth between 2008-2020. The rate remains constant at 50% of annual load growth for the remainder of the planning period of this 2009 Resource Plan.

For the planning period of this 2009 Resource Plan, FortisBC has estimated the DSM savings stream based on a continuation of the existing conservation program base, augmented by the introduction of additional energy efficiency measures and programs. As stated above, FortisBC expects to achieve the

Energy Plan DSM Target without the benefit of energy savings that may be attributed to codes and standards, price elasticity response, rate design impacts or energy savings incidental to Demand Reduction measures.

By 2020, the estimated cumulative energy efficiency savings and commensurate Demand Reduction will be 284 GWh, which equates to achievement of the Energy Plan DSM Target at a level of 51%.

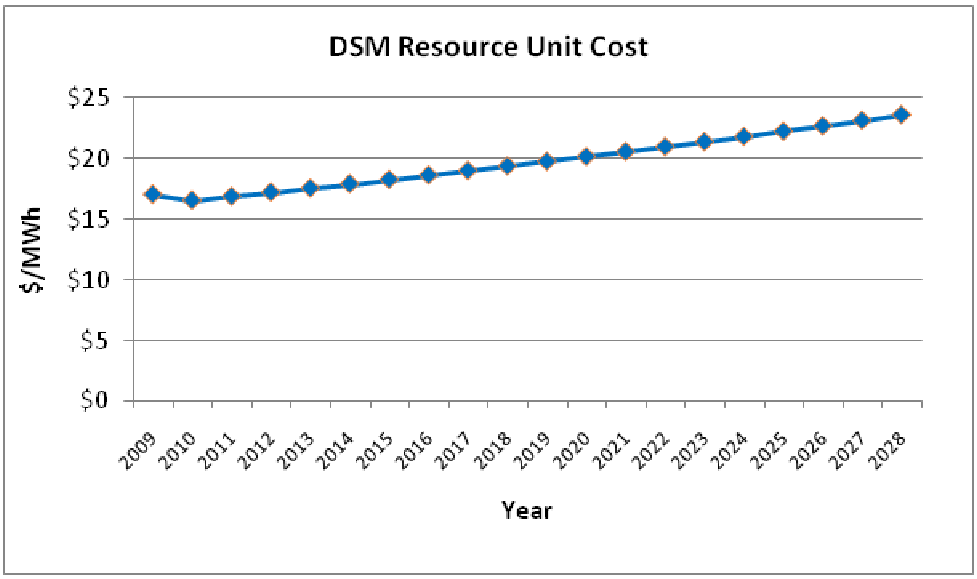
Figure 6.1.4.9: Cumulative DSM Resource Acquisition (GWh and MW)



6.1.4.10 2008 - 2027 Projected Annual DSM Resource Unit Cost

Over the five year period ending in 2008 FortisBC's average DSM-related unit cost (for program delivery and incentives), on a lifecycle basis, has been $11 per MWh. Over 2009-2010 the average unit cost is expected to increase to $17 per MWh. Average unit costs are expected to rise a further 2% annually thereafter as shown in Figure 6.1.4.10, which presents anticipated average annual unit costs (program and incentives) for 2008 to 2028. These costs will be updated in the 2011 DSM Plan.

Figure 6.1.4.10: Annual Unit Cost of DSM Program Delivery and Incentives



6.1.4.11 Demand Reduction

DSM resources can be targeted at reducing customers' peak load during over-all system peak demand periods. Demand Reduction initiatives are intended to reduce consumer electricity demand in response to price, monetary incentives or utility directives so as to maintain reliable electric service or avoid high electricity prices. Demand Reduction seeks to motivate consumers to manage their own energy demand by scaling back use or by shifting load. Demand Reduction measures may include:

- customer awareness and education campaigns;
- time-variable electricity rates, such as time-of-use and critical-peak pricing; and
- load control.

load control may, in turn, utilize a variety of methods to achieve Demand Reduction, including:

- customer-initiated load control in response to price signals;
- customer-initiated load control in response to utility requests; and
- utility-initiated load control agreed to with the customer.

A staff study[61] by the Federal Energy Regulatory Commission in the United States suggests that Demand Reduction capability currently represents between 2 to 4% of peak demand on a regional basis and up to

[61] Federal Energy Regulatory Commission: *Assessment of Demand Response & Advanced Metering*, September 2007.

6% in certain load pockets. In the FortisBC service area, those figures are the equivalent of a range of 16 to 49 MW annually by 2020 based on a load forecast of 809 MW.

With limited current experience in Demand Reduction, the Company will investigate achievable Demand Reduction potential more thoroughly as part of the 2011 DSM Plan. The scope of the Demand Reduction investigation will include the following:

- study of technology selection, effectiveness, and performance reliability;
- projections on the reasonable expected life of Demand Reduction measures;
- investigation of the market for providing Demand Reduction and customer acceptance;
- Demand Reduction potential estimates that meet NERC & WECC operating reliability standards;
- design of program components for successful implementation and operation of Demand Reduction resources;
- determination of costs for planning, design, marketing, operations controls, evaluation and verification protocols and practices; and
- determination of appropriate evaluation and screening criteria.

FortisBC believes that these areas deserve further study to define resource characteristics and suitability, followed by sharing of information for discussion with other utilities, stakeholders and regulators.

6.2 Resource / Load Gap

As noted above in Section 6.1.3, FortisBC is a capacity constrained utility. Existing resources are insufficient to meet peak demand. In 2009 the Company forecasts a capacity shortfall of 145 MW which is expected to grow to approximately 239 MW by 2028. Related to this peak capacity gap is an energy gap forecast to grow from 18 GWh in 2009 to approximately 131 GWh in 2028.

Figures 6.2-A and 6.2-B below are graphical representations of FortisBC's forecast energy and capacity load / resource balances through the planning period of this 2009 Resource Plan. In both figures the purple area indicates the contribution FortisBC expects its DSM initiatives will make to meeting the forecast gaps, and the beige area indicates the remaining gap.

Figure 6.2-A: Energy Load / Resource Balance (GWh)

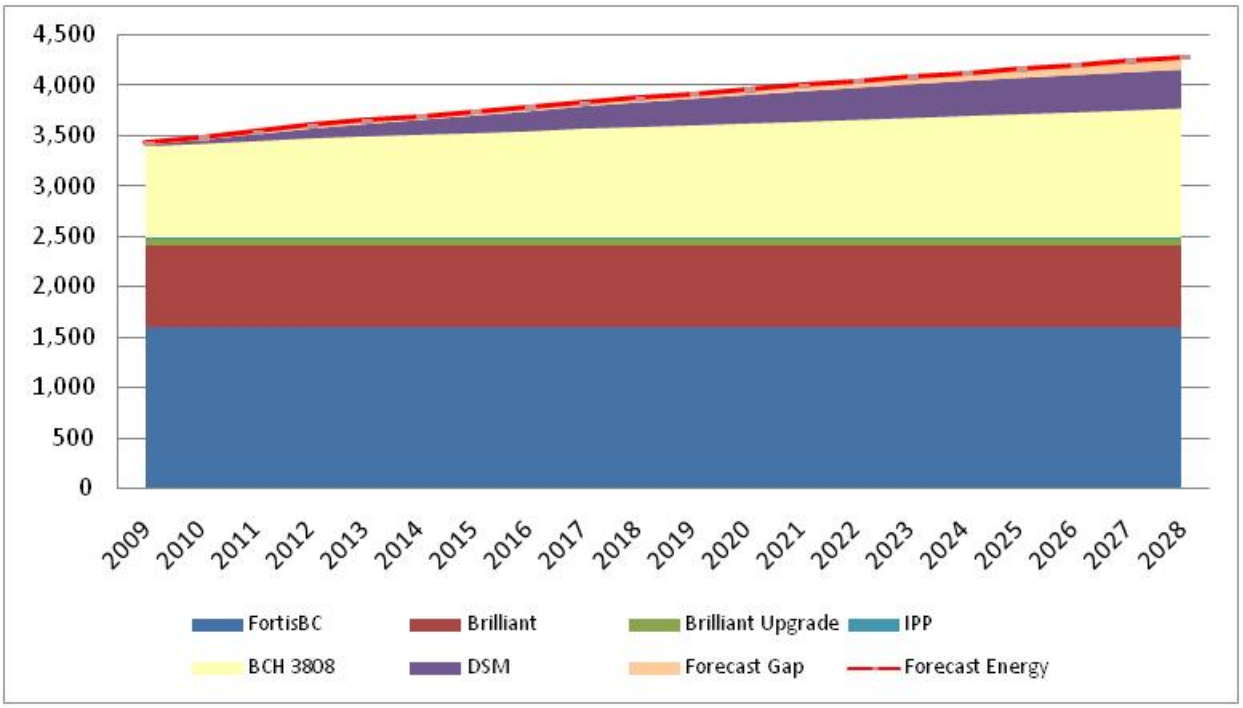


Figure 6.2-B: Capacity Load / Resource Balance (MW)

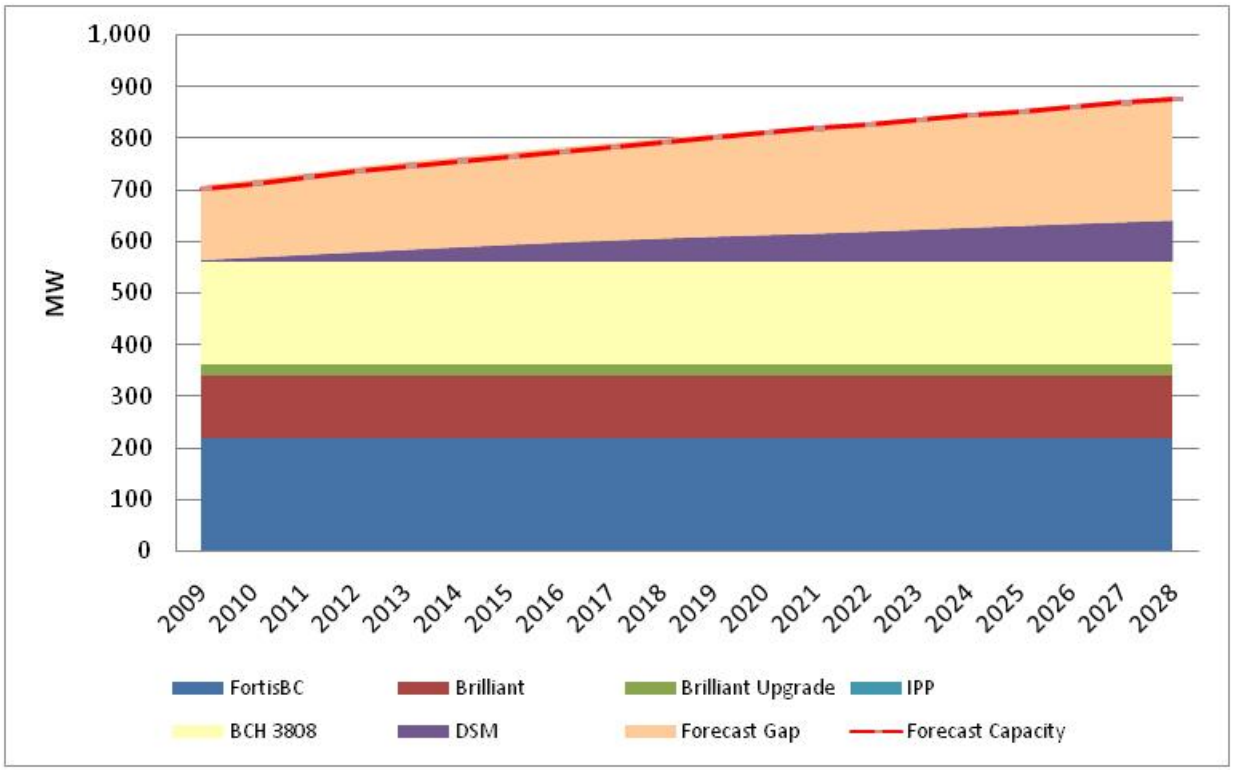


Table 6.2 below is a replication of the information above, in tabular form.

Table 6.2: Energy and Capacity Gap by Year

	Energy Gap (GWh)	Capacity Gap (MW)
2009	18.180	144.5
2010	21.806	150.6
2011	25.867	157.6
2012	29.144	164.8
2013	33.438	170.5
2014	35.764	174.8
2015	38.408	179.4
2016	41.353	184.0
2017	46.502	188.7
2018	52.137	193.4
2019	57.987	198.1
2020	63.317	202.8
2021	70.611	207.5
2022	77.274	212.2
2023	84.123	216.8
2024	90.523	221.4
2025	99.063	225.9
2026	108.190	230.4
2027	119.173	234.9
2028	130.467	239.2

6.3 Planning Margin

WECC requires utilities in the WECC region to have positive Operating Reserve Margins (hourly margins) in place at all times. WECC recommends (but does not require) that utilities also plan for positive margins on a long-term basis (called "**Planning Margin**"). A Planning Margin protects against the possibility of loss of supply owing to unplanned generating unit outage, transmission outage or unexpectedly high loads.

The percentage of system capacity used to define the size of the requisite Planning Margin is dependent upon the mix of generation resources employed in the system, the size of individual generating units relative to gross load, and the overall system size. If the system is large, comprised of many and diverse generating units and geographically diverse (such as BC Hydro's), it is considered "firm" in its ability to produce dependable capacity since the risk of individual unit outages is mitigated by the whole system. In this type of system, the recommended Planning Margin is a percentage of overall system capacity. WECC guidelines recommend, and large utilities utilize, a "percentage of overall system capacity" as their guideline for determining Planning Margin size. If the system is small and comprised of few generating

units (such as FortisBC's) and/or confined to a small geographic area, the recommended Planning Margin is calculated based upon the size of the largest single generating unit plus 5% of load responsibility[62].

FortisBC currently complies with WECC's hourly Operating Reserves requirements[63] which provide for an immediate, short term power supply reserve. However, FortisBC does not currently incorporate a Planning Margin. Therefore, the capacity load / resource balances shown in Figure 6.2-B and Table 6.2 above do not include a Planning Margin. The risk associated with the lack of a physical Planning Margin is two-fold. First, if a single generating unit or portion of the transmission system goes out of service, FortisBC must make potentially expensive market purchases for as long as required to source a replacement supply. Second, given that power supply requirement forecasts are based on "normal" weather patterns (as described in Section 5.3 above), if the service territory were to experience extremes of weather (extended hot or cold periods) beyond those contemplated by the forecast, there is potential for insufficient power supply (that is to say that the resources planned to meet the expected forecast may prove insufficient). Accordingly, FortisBC believes it consistent with good utility practice to consider as well the additional load implied by a Planning Margin.

The Company commissioned two studies, the first by Willis Energy Services Ltd. and the second by Manitoba Hydro's HVDC Research Center, to help analyze the requirement for a Planning Margin. The reports, both completed in late 2007, are attached as Appendices H-1 and H-2, respectively. Following is a summary of these two studies.

- Willis Energy Services Ltd. ("**Willis**") was asked to determine the Planning Margin that would be required to satisfy WECC's recommended Planning Margin, given the uniqueness of FortisBC's resources and loads. Willis recommends that FortisBC acquire a positive Planning Margin of approximately 9% (62 MW in 2009), based upon system makeup, generator unit sizes and forecast generator unit outages. Table 6.3 below provides more detail for milestone years through the planning period of the 2009 Resource Plan.

[62] Willis Energy Services Ltd. Planning Reserve Margin (Appendix H-1)

[63] Section B. Requirements on Page 1 of WECC Standard BAL-STD-002-0 - Operating Reserves

Table 6.3: Willis Energy Service Ltd.'s Summary Recommended Planning Reserve Above Load Forecast (MW)[64]

	2009	2013	2018	2023	2027
A) Expected Load Forecast Annual Peak Demand (MW)	701	746	792	836	868
B) Forecast Peak Demand minus BCH 3808 Purchase (MW)	501	546	592	636	668
C) WECC Criteria (5% of Expected Load Forecast (B)) (MW)	25	27	30	32	33
D) Largest Generating Unit (Brilliant unit)	37	37	37	37	37
E) Total Recommended Planning Margin (MW) (sum C & D, above)	**62**	**65**	**67**	**69**	**71**
F) Recommended Planning Margin as Percent of A (E/A)	8.90%	8.66%	8.45%	8.27%	8.15%
G) Existing Operating Reserve (MW)	**18**	**18**	**18**	**18**	**18**
H) Additional Planning Margin Required (MW)	**45**	**47**	**49**	**51**	**53**
I) Additional Planning Margin Required as a Percent	6.36%	6.28%	6.20%	6.14%	6.10%

- Manitoba Hydro's HVDC Research Centre ("**HVDC**") was engaged to approach the analysis from a technical perspective, answering the question: "Given a gross load supported by a specific set of generating units/sizes and types, what should be the planning margin necessary to meet minimum industry requirements?" Further, HVDC was asked to make this assessment considering not only FortisBC's existing resources, but also a variety of generic potential resources that may be considered in the future. The HVDC work was completed in late 2007.

  HVDC modeled FortisBC's system from the perspective of being unable to meet its load only 1 day out of 10 years owing to generator unit outages. (This is a utility standard in wide-spread use.) HVDC used a number of scenarios, including:

  - new resources from hydro generation with unit reliability similar to FortisBC's, utilizing Teck's Waneta facility as the model;
  - new "firm" resources from BC Hydro similar to the existing BC Hydro PPA; and
  - new wholesale market resources from a Mid-C source, utilizing Combined Cycle Gas Turbine (CCGT) performance data for unit reliability.

  The HVDC study was done on a probabilistic basis, using a Monte Carlo simulation technique, and taking into account the 20 year forecast of annual peak loads (i.e., capacity forecast), hourly load duration based on an averaging of historical durations which were projected forward using the peak capacity forecast, outage rates of existing resources based on historical data, outage rates of new resources based on typical outage rates (e.g., gas turbines) and outage rates for purchases based on Teck's Waneta plant.

[64] Table 6.3 has been updated since the original completed in 2007 by Willis Energy Services Ltd. in order to include current forecast loads.

The HVDC work suggested a Planning Margin requirement that varied from:

- a low of 6.4% in 2008 (reducing to 4.4% in 2027) when new resources are available from the firm BC Hydro system; to
- a high of 16% in 2008 (reducing to 14.4% in 2027) when new resources are available from a market-based Combined Cycle Gas Turbine.

6.3.1.1 Planning Margin Conclusions

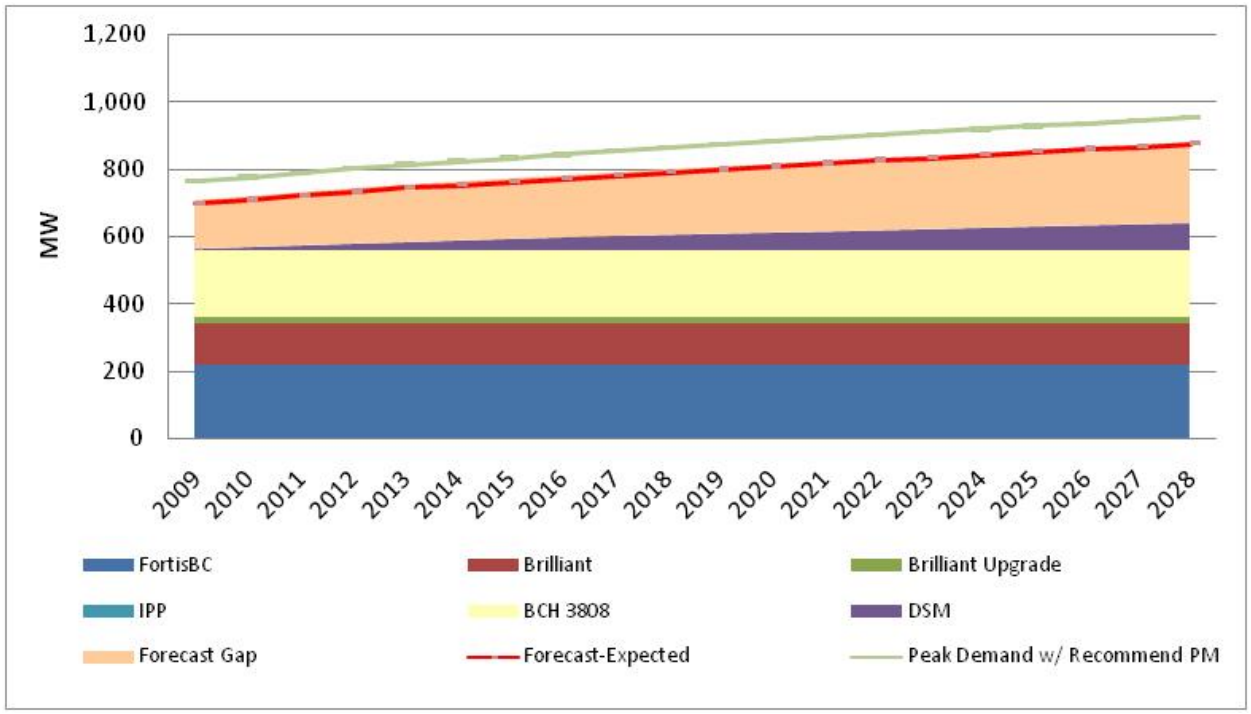
The HVDC study was important in assisting FortisBC to understand the "standard" utility approach to Planning Margin that underpins the WECC recommendation. However, FortisBC concluded that Willis' report and recommendations were more clearly applicable to the Company's system.

As noted above, the BC Hydro PPA is considered "firm" in the Planning Margin context, given the size and reliability of the BC Hydro system as the resource supporting the BC Hydro PPA supply obligation. FortisBC's owned generation and the Brilliant PPA are also considered "firm" by virtue of the fact that the Canal Plant Agreement negates hydrological risk for the FortisBC Plants and the Brilliant plant. FortisBC's risk, therefore, is limited to the probability of generator unit outage of the non-BC Hydro resources (including FortisBC's owned generation and the Brilliant PPA).

Therefore, FortisBC's system makeup, including firm supply contracts, limits the Planning Margin requirement to the amounts noted by Willis – 60 MW to 70 MW (see Table 6.3) – which is the sum of FortisBC's single largest generating unit (one of the Brilliant plant units) plus 5% of load responsibility. For example, the 2009 peak forecast is 701 MW. From this is deducted the capacity available from the BCH PPA for a total of 501 MW responsible load. 5% of this forecast load is 25 MW to which is added the 37 MW Brilliant generating unit, for a total Planning Margin requirement of 62 MW. Deducting FortisBC's existing Operating Reserve, additional Planning Margin requirements recommended by Willis are 45 MW, increasing to 55 MW (as load grows) during the planning period of this 2009 Resource Plan (see Table 6.3).

Figure 6.3.1.1 below repeats the capacity load / resource balance graphic from Figure 6.2-B but includes a Planning Margin (at an average 9% of capacity) as indicated by the green line.

Figure 6.3.1.1: Capacity Load / Resource Balance with Planning Margin (MW)



FortisBC concludes that it is prudent and necessary to acquire and maintain a Planning Margin resource in excess of forecast gaps.

7 RESOURCE OPTIONS & PORTFOLIOS

7.1 Introduction

FortisBC considered a wide variety of potential resource options in the course of its preparation of this 2009 Resource Plan. From that preliminary array, the Company selected a shorter list of potential options that it felt would be suitable for examination for possible inclusion in potential resource option portfolios.

To arrive at that shorter list, FortisBC examined certain key attributes of each potential resource option (including its technical performance capabilities, estimated cost of development and anticipated project life). By comparing the various options' relative attributes in each category, the Company was able to develop a list of potential resource alternatives from which it could select options for combination in various portfolios having the potential to meet the Company's objectives described in Section 3.1 above.

The Company has documented the process it undertook, together with its conclusions, in detail, in the Resource Options Report attached as Appendix I-1. A summary of the attributes of the various resource options FortisBC considered is set out in Table 7.1-A below.

Table 7.1-A: Resource Option Attribute Summary (C$2009)

Resource Type	Installed Capacity (MW)	Dependable Capacity (MW)	Maximum Average Annual Energy (GWh)	Meets BC Clean Criteria (Y/N)	Greenhouse Gas (CO2) Emissions (t/GWh)	Capital Cost ($000s)	UEC ($/MWh)	UCC ($/MW-yr)	Project Life (yrs)
Combined Cycle Gas Turbine	243	236	1,887	N	365	326,400	102.43	143,569	25
Combined Cycle Gas Turbine	50	48.5	294	N	365	142,800	141.64	343,120	25
Simple Cycle Gas Turbine	103	97.8	171	N	500	71,400	na	72,150	30
Simple Cycle Gas Turbine	42.3	38.2	67	N	500	43,860	na	115,340	30
Biomass Woodwaste	80	80	640	Y	0	177,539	124.98	na	20
Small Hydro with Capacity	40	37.2	154	Y	0	148,900	87.92	337,992	40
Wind Generation	30	7.5	66	Y	0	61,586	113.55	na	20
Pumped Storage	200	200	584	Y	0	510,000	na	256,556	50

Notes:
-The costs are in Real C$2009
-UEC and UCC are levelized at a discount rate of 8%
-SCGT and CCGT's UECs and UCCs include cost of fuel.
- UEC and UCC are indicative values under presumed operating conditions as described in Resource Option Report in Appendix E

In order to facilitate a comparison of the economics of different options, FortisBC required unit cost calculations. These calculations include two major comparators: Unit Energy Cost in $ per MWh ("**UEC**") and Unit Capacity Cost in $ per MW ("**UCC**")[65].

[65] For more detail, and examples, see Appendix I-1

UEC: Unit Energy Costs are based on the net present value of the annual energy costs for an option over the option's assumed life divided by the net present value of annual energy generated by the option. The energy costs include capital, fuel costs, the variable and fixed operating and maintenance costs and the greenhouse gas offset costs.

UCC: Unit Capacity Costs are based on the net present value of an option's capital costs and fixed operating and maintenance costs over the life of an option divided by the net present value of the capacity provided by the option over its life.

While these comparators are useful, they are not interchangeable and are useful only in comparing "like" resources. For example, UEC is useful in comparing energy resource with energy resource (such as Wind versus Combined Cycle Gas Turbine) and UCC is useful in comparing capacity resource with capacity resource (such as Pumped Storage Hydro versus Simple Cycle Gas Turbine). But they do not facilitate comparison of energy resources with capacity resources. For example, a capacity resource such as a Pumped Storage Hydro facility (which provides reliable, firm capacity but relatively low volumes of energy) would have a disproportionately high UEC when compared with a Wind resource (which provides relatively high volumes of energy yet is not a firm source of capacity). It is also important to note that the generic UEC and UCC are only guides for comparison. When specific resources are operated to meet specific system demands their forecast Unit Costs may vary from the generic.

Another useful comparator is **Unit Construction Cost**, measured in construction capital cost per MW of capacity. Table 7.1-B below lists the various resource options' unit construction costs, based upon data in the Resource Options Report. However, as noted in the Canaccord Adams June 10, 2008 research paper, Power in Canada: The Next Generation, "While inflation indices are likely impossible to accurately predict, it is unrealistic to estimate future construction costs based on today's economics or cost structure. According to an index developed by HIS Inc. and Cambridge Energy Research Associates, the cost of North American power plant construction for the period ending October 31, 2007 increased 27% in the previous 12 months and 19% in the previous six months."[66] Conversely, given the global economic situation as it exists in early 2009, it is possible that construction costs may turn out to be less than forecast in the Resource Options Report attached as Appendix I-1. The unit construction cost of any specific resource option will be better defined at the time of a CPCN application.

[66] Canaccord Adams, Equity Research, Power in Canada: The Next Generation. June 10, 2008.

Table 7.1-B: Resource Option Unit Construction Costs (C$2009)

Resource Type	Dependable Capacity (MW)	Capital ($millions)	Unit Construction Cost ($millions/MW)
Combined Cycle Gas Turbine	236	326	1.38
Combined Cycle Gas Turbine	49	143	2.94
Simple Cycle Gas Turbine	98	71	0.73
Simple Cycle Gas Turbine	38	44	1.15
Biomass Woodwaste	80	178	2.22
Small Hydro with Capacity	37	148	3.98
Wind Generation	8	62	8.21
Pumped Storage	200	510	2.55

** Unit Construction Cost ($/MW) is based on Dependable Capacity.*

FortisBC asked Willis Energy Services Ltd., which provided the capital expenditure estimates in the Resource Options Report attached as Appendix I-1, to comment on the confidence range it attached to those estimates. Willis Energy Services Ltd.'s response is summarized in Table 7.1-C below.

Table 7.1-C: Resource Option Capital Cost Confidence Range

Resource Option	Cost Estimate Range	Comments
Combined Cycle Gas Turbine	-10 % to +20 %	Well defined plant type
Simple Cycle Gas Turbine	-10 % to +20 %	Well defined plant type
Biomass Woodwaste	-10 % to +30 %	Well defined but relatively complex plant type
Small Hydro with Capacity	-20 % to +30 %	Site dependant
Wind	-20 % to +30 %	Site dependant
Pumped Storage Hydro Facility	-20 % to +50 %	Plant type not well defined and site dependant

7.2 Assessment Criteria and Assumptions

This Section 7.2 describes the criteria FortisBC used in assessing the relative ability of various resource options, and resource option portfolios, to provide a balanced solution to FortisBC's power supply requirements. It then sets out the assumptions FortisBC used to provide consistency when comparing the resource option portfolios.

7.2.1 Assessment Criteria

FortisBC developed four criteria for its assessment of potential resource options. Those criteria are as follows:

1. Does the resource option provide complete coverage of FortisBC's forecast energy and capacity gaps (after application of DSM), and does it include a Planning Margin?
2. Does the resource option minimize environmental impacts?
3. Does the resource option meet all of the applicable Policy Actions of the BC Energy Plan (see Table 3.5.2.1)?
4. Is the resource option economical?

FortisBC assessed individual resource options against these four criteria and combined them into an array of resource option portfolios for assessment of those portfolios' respective ability optimally to satisfy those same four criteria.

FortisBC considered many potential resource options that it did not advance to the portfolio review stage, including, for example, large hydro, run-of-river hydro and Combined Cycle Gas Turbines. In general, FortisBC discontinued its assessment of each such option because the Company considered that the option did not provide a balanced solution to the Company's assessment criteria. Some specific reasons for discontinued assessment included the following:

- The option produced excessive surplus energy relative to the Company's forecast gaps. Examples of such options include:
  - Combined Cycle Gas Turbine
  - Large hydro
- The option produced energy shaped (i.e. time of year) such that it did not match the Company's requirements. An example of such options is:
  - Run-of-river hydro.

7.2.2 Assumptions

In completing the portfolio comparisons, FortisBC used the following common assumptions to ensure consistency:

- Existing resources
- Planning Margin
- Greenhouse gas costs
- Market costs
- Surplus energy sales
- Financial
- Transmission

7.2.2.1 Existing Resources

FortisBC has assumed all of the FortisBC Plants, the BC Hydro PPA and the Brilliant PPA to be stable and reliable generation resources throughout the planning period of this 2009 Resource Plan. Therefore, for the purposes of comparing portfolios of additional resource options, FortisBC has excluded from its consideration these existing resources. Further, FortisBC has assumed that expected DSM performance will provide the contribution described in Section 6.1.4 above and, therefore, for the purposes of comparing resource option portfolios, the Company treats DSM as an existing resource. (In other words, FortisBC has assumed that DSM results will account for 50% of load growth and the related capacity, by 2020). The Company has considered only incremental generation resources.

As described in detail in Section 6.1.2.2 above, FortisBC is currently engaged in negotiations with BC Hydro for the renewal of the BC Hydro PPA. FortisBC is assuming, for the purposes of this 2009 Resource Plan, that the BC Hydro PPA will be renewed and will contain (among other terms) the following:

- an acknowledgement by BC Hydro of FortisBC's right to receive 200 MW of firm capacity and all associated energy; and
- exclusion of the existing export restriction insofar as it would apply to new generation resources.

7.2.2.2 Planning Margin

The resource option portfolio analysis reflected in this 2009 Resource Plan incorporates a Planning Margin (discussed in detail in Section 6.3 above) that escalates as load grows from approximately 45 MW to approximately 55 MW over the planning period of this 2009 Resource Plan. In all resource option portfolios, for any period prior to the acquisition of a physical asset dedicated to Planning Margin, FortisBC has approximated the Planning Margin cost as a capacity product purchased from the British Columbia electricity market[67]. Capacity cost assumptions are the same as the demand charge assumptions noted in Section 7.4.4.2.1 below.

In order to manage risks while mitigating rate impacts FortisBC has modeled an incremental acquisition of the market-based interim Planning Margin (discussed in detail in Section 7.4.1 below).

7.2.2.3 Greenhouse Gas Costs

All of the resource option portfolios contain some element of greenhouse gas-related costs. Assigning a predictable value to these costs is difficult in the absence of a formalized and regulated cost structure. For purposes of the BC Hydro 2008 LTAP, BC Hydro engaged Natsource to forecast potential greenhouse gas-related cost impacts on new generation resource planning. That analysis confirms that regulation of this area continues to be subject to a maturing policy framework. In its mid-point forecast, Natsource estimated an escalating cost structure starting at approximately $15/tonne of emissions. In order to have a consistent value for application to the various resource portfolios under consideration, and in the absence of any other generally-accepted greenhouse gas-related cost structures, FortisBC has assumed a cost factor mirroring the timed escalations in the Carbon Tax Act. The timing of those escalations is as follows:

July 1, 2008	$10 per metric tonne
July 1, 2009	$15 per metric tonne
July 1, 2010	$20 per metric tonne
July 1, 2011	$25 per metric tonne
July 1, 2012	$30 per metric tonne

7.2.2.4 Market Costs

For all portfolios FortisBC has assumed that the Company would continue to rely upon the wholesale electricity market for periods prior to new supply resources coming online. Therefore, FortisBC has utilized a wholesale electricity price forecast to determine a market cost of supply during those periods.

[67] The BC electricity market is inclusive of BC Hydro, the Columbia Power Corporation/Columbia Basin Trust group, Teck and other BC-based IPPs.

FortisBC believes that a reasonable electricity price forecast must use inputs that include the forecast price of natural gas, projected economic activity, and regional supply, demand and deliverability projections. For purposes of this 2009 Resource Plan, FortisBC adopted the BC Hydro 2008 LTAP Mid-range Forecast[68]. BC Hydro's forecast was recently tested in the BC Hydro 2008 LTAP process before the Commission and is, in FortisBC's view, a reasonable estimate of future wholesale electricity market prices. These forecast prices are averages, and do not attempt to account for the volatile nature of the wholesale market. Column 1 of Table 7.2.2.4 below represents this forecast.

To the Column 1 price FortisBC has added a transmission cost (Column 2) to approximate the cost of moving the power to FortisBC's load (including tariff rates for hourly point-to-point scheduling, Teck's charges for use of its transmission line, and an estimate for reactive supply and voltage control costs related to the transmission). This does not include any provision for costs relating to any new generation - related transmission facilities necessary to connect the generation to the grid. Column 3 includes the Bonneville Power Administration and General Wheeling Agreement loss rate, totaling 6.9%. Column 4 is an estimate of the greenhouse gas-related costs associated with purchases that is, in the absence of any other formalized cost structure, based upon the carbon tax contemplated by the Carbon Tax Act. Table 7.2.2.4 below sets out the forecast wholesale market electricity price.

[68] Willis Energy Services derived the BCH LTAP Mid-range forecast from BCH's graphical presentation (Figure 4.6 of the BC Hydro 2008 LTAP) and adjusted it to C$2009 for FortisBC.

Table 7.2.2.4: Wholesale Market Electricity Price Forecast

Year	1. BCH 2008 LTAP Mid Forecast (2009 Real C$/MWh)	2. Transmission Adder-- Wholesale Market ($/MWh)	3. Transmission Loss Adjustment (6.9%)	4. GHG Adder $/MWh (equivilent to BC Carbon Tax)	FortisBC Price Forecast $/MWh (1+2+3+4)
2009	$50.39	$6.45	$3.48	$4.40	$64.71
2010	$50.91	$6.45	$3.51	$6.03	$66.91
2011	$44.09	$6.45	$3.04	$7.61	$61.18
2012	$39.89	$6.45	$2.75	$9.11	$58.20
2013	$43.56	$6.45	$3.01	$9.74	$62.76
2014	$46.19	$6.45	$3.19	$9.74	$65.57
2015	$49.34	$6.45	$3.40	$9.74	$68.93
2016	$49.34	$6.45	$3.40	$9.74	$68.93
2017	$46.71	$6.45	$3.22	$9.74	$66.13
2018	$48.81	$6.45	$3.37	$9.74	$68.37
2019	$50.39	$6.45	$3.48	$9.74	$70.06
2020	$54.58	$6.45	$3.77	$9.74	$74.54
2021	$58.78	$6.45	$4.06	$9.74	$79.03
2022	$58.78	$6.45	$4.06	$9.74	$79.03
2023	$59.83	$6.45	$4.13	$9.74	$80.16
2024	$60.88	$6.45	$4.20	$9.74	$81.28
2025	$60.88	$6.45	$4.20	$9.74	$81.28
2026	$62.98	$6.45	$4.35	$9.74	$83.52
2027	$64.03	$6.45	$4.42	$9.74	$84.64
2028	$65.08	$6.45	$4.49	$9.74	$85.77

7.2.2.5 Surplus Energy Sales

It is assumed that the Company will be able to economically dispose of surplus energy produced by the new resources reflected in the resource option portfolios. Transmission charges would be determined at the time of sale (when the purchaser is known), and therefore no transmission charges are included in the forecast. However, as FortisBC would want to gain the benefit of power sold from new clean resources, the greenhouse gas adder remains applicable. Table 7.2.2.5 below sets out FortisBC's surplus sale price forecast.

Table 7.2.2.5: Surplus Sale – Price Forecast

Year	1. BCH 2008 LTAP Mid Forecast (Real C$/MWh)	2. GHG Adder $/MWh (equivilent to BC Carbon Tax)	FortisBC Price Forecast $/MWh (1+2)
2009	$50.39	$4.40	$54.78
2010	$50.91	$6.03	$56.95
2011	$44.09	$7.61	$51.69
2012	$39.89	$9.11	$49.00
2013	$43.56	$9.74	$53.31
2014	$46.19	$9.74	$55.93
2015	$49.34	$9.74	$59.08
2016	$49.34	$9.74	$59.08
2017	$46.71	$9.74	$56.46
2018	$48.81	$9.74	$58.56
2019	$50.39	$9.74	$60.13
2020	$54.58	$9.74	$64.33
2021	$58.78	$9.74	$68.53
2022	$58.78	$9.74	$68.53
2023	$59.83	$9.74	$69.58
2024	$60.88	$9.74	$70.63
2025	$60.88	$9.74	$70.63
2026	$62.98	$9.74	$72.73
2027	$64.03	$9.74	$73.78
2028	$65.08	$9.74	$74.83

7.2.2.6 Financial

1. All financial values are presented in real 2009 dollars.

2. A capital structure of 60% debt and 40% equity has been used.

3. Financing costs were calculated using a flat 7.0% interest rate and a return on equity of 9.0%.

4. Estimated operation and maintenance costs are included in the cost of power production for each resource option.

5. The impact of property taxes is not included in the resource option portfolio analysis. Property taxes are specific to asset types, property footprint, and location – none of which have been determined at this time. FortisBC does not expect this factor to change the relative ranking of the resource option portfolios.

6. All portfolio capital additions are assumed to go into service December 31 of the prior year. Depreciation and Financing costs are therefore calculated for the first full year of service. The

half year CCA rule was applied in the year prior. Depreciation rates have been calculated as the composite rate for the different portfolios based on their "project life".

7. Income tax has been calculated using the following assumed combined federal and provincial tax rates:

Year	2009	2010	2011	2012 and beyond
Rate	30.00%	28.50%	26.50%	25.00%

8. A real discount rate of 8.0% has been used. The discount rate represents FortisBC's 20 year weighted average cost of capital (after tax) of 10.0% net of inflation of 2.0%.

7.2.2.7 Transmission

As described in detail in Section 3.8 above, FortisBC assumes that additional transmission infrastructure will be required to support the Okanagan load center if generation is not located in the North Okanagan region. This infrastructure will be required in the early to mid part of the planning period of this 2009 Resource Plan and could include any of the facilities described below in Table 7.2.2.7. (Note that the information in Table 7.2.2.7 below is repeated from Table 3.9.2.2.4).

Table 7.2.2.7: Possible Transmission Projects to Support Kelowna Load Growth

	Project Description	Estimated Cost (conceptual level)
1.	Construction of a second 230 kV line from Kelowna to Penticton	$70 million
2.	Construction of a third 230 kV line between Ashton Creek and Vernon (BCTC-owned line)	$70 million
3.	Construction of a third 230 kV line from BCTC between Ashton Creek and Kelowna (FortisBC-owned line)	$90 million
4.	Construction of a new 500/230 kV supply source in the Kelowna area	$500 million

Numerous factors need to be considered when selecting from the above options. These include:

- the remaining supply capacity (if any) in BCTC's Vernon system;
- the project capital cost and associated rate impact;
- environmental and land issues (i.e. new rights-of-way for transmission lines, etc.);
- any consequential benefits such as improvements in provincial transmission capacity; and
- the length of time for which the project will provide sufficient capacity.

Further, a balancing of objectives relating to these factors may be required. For example, the lowest capital cost project with the least environmental impact may also have the shortest useful lifespan and thus in the long term have a higher total cost (since additional reinforcement may be required sooner).

Location of new generation resources in FortisBC's North Okanagan service territory may defer or eliminate the need for these transmission infrastructure additions. In any event, the need for additional transmission infrastructure must be taken into account in the overall assessment of a resource option portfolio's ability to provide a balanced solution.

7.3 Resource Option Portfolio Analysis

7.3.1 Portfolio Overview and Introduction

FortisBC has created three portfolios of resource options, as described below.

Resource Option Portfolio 1 ("P1 – BC MARKETS")

This portfolio assumes that FortisBC will satisfy its existing and forecast capacity and energy gaps, and its need for a Planning Margin, pursuant to new power purchase agreements entered into with British Columbia-based power suppliers. These suppliers could be any of BC Hydro, Columbia Power Corporation/Columbia Basin Trust, Teck and/or other Independent Power Producers. New generation resources may have to be built to supply FortisBC's requirements, and it is the Company's expectation that it would have to pay market prices for the capacity and energy so supplied. This portfolio of generation resources is modeled to mimic the operational characteristics of those resources that may have to be built to supply FortisBC's load.

Resource Option Portfolio 2 ("P2 – GAS")

This portfolio assumes that FortisBC will satisfy its existing and forecast capacity and energy gaps, and its need for a Planning Margin, through construction of a series of Simple Cycle Gas Turbine units, the sizes and timing-of-acquisition of which are determined by the growing size of the Company's forecast capacity gap.

Resource Option Portfolio 3 – ("P3 – HYBRID")

This portfolio assumes that FortisBC will satisfy its existing and forecast capacity and energy gaps, and its need for a Planning Margin, through construction of a combination of clean, renewable resources with a gas-fueled peaking resource. Small Hydro with Capacity and Pumped Storage Hydro facilities provide the peaking and storage capacity necessary to shape energy to meet FortisBC's requirements. Later in the planning period, a source of intermittent Clean energy (for modeling purposes, Wind) is added to the portfolio. A Simple Cycle Gas Turbine provides short term peaking capability pending the Pumped Storage Hydro's in-service date and then converts to a standby Planning Margin role.

Table 7.3.1 below describes these three resource portfolios, defining them in terms of type of resource, planned in-service date, installed and dependable capacity, firm energy, project life and project capital cost.

Table 7.3.1: Portfolio Summary

Portfolio	Description	Installed Capacity (MW)	Dependable Capacity (MW)	Firm Energy Generated (GWh/yr)	Project Life (yrs)	Capital Cost (C$2009 millions)
P1 - BC Markets	Could include any of BC Hydro, Teck, Columbia Power Corp, and/or other BC-based Independent Power Producers	334	326	N/A	N/A	N/A
	Avoidable Transmission:					
	- SVC, Kelowna in **2013**					$35
	- Vaseux Transformer in **2016**					$8
	Total:	**334**	**326**	**N/A**		**$43**
P2 - Gas	- 2 x 42 MW Simple Cycle Gas Turbines (SCGT), and 2x 103 MW SCGT in **2014**	290	272	Only as required	30	230
	- 1 x 42 MW SCGT in **2020**	42	38	Only as required	30	$44
	Total:	**332**	**310**	**N/A**		**$274**
P3 - Hybrid	- 2 x 42 MW SCGTs in **2014**	84	76	Only as required	30	$88
	- Small Hydro with Capacity in **2017**	40	37	154	40+	$149
	- Pumped Storage Hydro (PSH) in **2019**	200	200	Only as required	50+	$510
	- Clean (Wind) in **2021**	30	8	66	20	$62
	Total:	**354**	**321**	**220**		**$809**

7.3.1.1 P1 - BC MARKETS

This resource option portfolio assumes that FortisBC will rely upon supply options available from third parties in the British Columbia electricity market. Since a portion of FortisBC's existing resources is already so acquired, FortisBC considers it appropriate to examine the British Columbia market as a potential solution to FortisBC's additional resource requirements. Therefore, the P1 – BC MARKETS portfolio assumes long-term power purchase agreements with British Columbia-based power suppliers that would be shaped to match the Company's load requirements. The portfolio assumes no reliance upon suppliers located outside of British Columbia.

Owing to the existing provincial load / resource gap, as described by BC Hydro in the BC Hydro 2008 LTAP (see Section 3.6.2 above), new generation resources may have to be built to supply FortisBC's requirements. The owners of those new resources would charge for the capacity, firm and non-firm energy shaped to FortisBC's needs and subject to the production specifications of the resource.

The P1 - BC MARKETS portfolio could be modeled to solve, precisely, in each year of the forecast, FortisBC's energy and capacity needs. However, in order to adequately shape a power purchase agreement to meet the Company's needs, the supplier would be required to dispose of any surplus power. Any cost associated with this activity would likely be loaded into the power purchase agreements as a shaping charge to FortisBC.

For modeling purposes, the P1 – BC MARKETS portfolio is structured to illustrate a possible resource configuration that mimics those resource capabilities required to meet the Company's capacity, energy, and Planning Margin requirements. It assumes that those generation resources will be available as follows:

- 84 MW of Simple Cycle Gas Turbine in 2014. FortisBC assumes that 2014 is the earliest date that a Simple Cycle Gas Turbine could be delivered. After 2019, this resource option would solely provide for FortisBC's Planning Margin requirements.

- 250 MW of Hydro Capacity timed as follows, to provide capacity and peak-related energy needs:
    - 100 MW in 2015
    - 25 MW in 2017
    - 100 MW in 2019, at which time the Simple Cycle Gas Turbine would exclusively be contracted for Planning Margin requirements
    - 25 MW in 2025

As noted above, the P1 – BC MARKETS portfolio assumes that additional British Columbia based generation resources will be added to meet FortisBC's requirements, and models those resources listed above as examples of resource types that could be used to close the Company's existing and forecast capacity and energy gaps. In actuality, other resource types might be used.

7.3.1.2 P2 - GAS

This resource portfolio models new peaking generation resources that are 100% natural gas fueled. FortisBC is capacity constrained in that it has existing and forecast peak capacity deficiencies. The Company's energy gaps are primarily associated with those peak demand requirements.

FortisBC chose to include Simple Cycle Gas Turbines in this portfolio because of their peaking attributes and capabilities (including short start and stop times). Simple Cycle Gas Turbines also provide an economical Planning Margin. Further, Simple Cycle Gas Turbines provide flexibility in that they can be relatively quickly converted to a Combined Cycle Gas Turbine base-load plant to provide additional energy resources if FortisBC's load profile were to shift more towards requiring greater volumes of energy.

The acquisitions reflected in this resource portfolio are timed to minimize annual cost impacts, while maximizing the positive impact upon the Company's capacity and energy gaps. Therefore, this resource portfolio assumes that those generation resources will be available as follows:

- 2 x 42 MW Simple Cycle Gas Turbines, and 2 x 103 MW Simple Cycle Gas Turbine in 2014.
    - The 2 x 42 MW units provide for Planning Margin requirements, and
    - The 2 x 103 MW units provide peak capacity, and peak-related energy support.
- An additional 42 MW Simple Cycle Gas Turbine in 2020 to keep the forecast capacity gap closed.

7.3.1.3 P3 - HYBRID

This resource portfolio models a hybrid approach to solving the Company's existing and forecast capacity and energy gaps through the acquisition of peaking, capacity storage and energy shaping capabilities utilizing both natural-gas fueled and renewable resources. Specifically, this portfolio models the initial acquisition of peaking capacity (Simple Cycle Gas Turbine) that is later converted to a Planning Margin role, renewable resources (wind and small hydro), and peaking capacity combined with power storage and shaping capability (Pumped Storage Hydro).

FortisBC chose to include Simple Cycle Gas Turbines in this portfolio because of their peaking attributes and capabilities (including short start and stop times). Simple Cycle Gas Turbines also provide an economical Planning Margin. Further, Simple Cycle Gas Turbines provide flexibility in that they can

relatively quickly be converted to a Combined Cycle Gas Turbine base-load plant to provide additional energy resources if FortisBC's load profile were to shift more towards requiring greater volumes of energy. The acquisitions are timed to spread out annual cost impacts and to account for necessary lead time for construction, while maximizing the positive impact on the Company's capacity and energy gaps.

This resource portfolio assumes that those generation resources will be available as follows:

- 2 x 42 MW Simple Cycle Gas Turbines in 2014 to provide peak capacity support. It is expected that 2014 is the earliest date that Simple Cycle Gas Turbines could be brought into service. When no longer needed in the peak support role (after the Pumped Storage Hydro facility comes on line) they would be placed on standby in the Planning Margin role.

- 40 MW Small Hydro with Capacity in 2017.

- 200 MW Pumped Storage Hydro facility in 2019 to take over the peaking role from the Simple Cycle Gas Turbines and allow for storage to support both customer-owned and other system intermittent renewables such as Wind.

- 30 MW of Clean Resource (30 MW of Wind used for modeling purposes) in 2021

7.4 Resource Portfolio Analysis

The balance of Section 7 provides analysis of each of the three portfolios' respective performance against the criteria of gap closure, environmental impacts, success in meeting BC Energy Plan Policy Actions, and economics. Section 7 concludes with a Decision Matrix exercise that assists in selecting the optimal solution.

7.4.1 Application of Criterion 1

Does the portfolio, after new resources are in place and after application of DSM, close the forecast capacity and energy gaps, and provide a Planning Margin?

All three portfolios meet this criterion, as follows.

P1 - BC MARKETS

Prior to 2013, FortisBC would continue to rely on the wholesale electricity market to meet its capacity and energy gaps and its requirement for a Planning Margin. FortisBC's projected capacity gap of approximately 171 MW in 2013 is reduced to 98 MW in 2014 when the Simple Cycle Gas Turbine resource is in place, and to 3 MW in 2015 with the first tranche of hydro-based capacity. The peak-

related energy gap is eliminated by 2015. Following tranches of hydro-based capacity are required to cover the growing peak load over time.

The P1 – BC MARKETS portfolio is modeled with the expectation that it will take until 2019 for the British Columbia market to have developed sufficient peaking capacity to supply 100% of FortisBC's Planning Margin requirements with dedicated resources. Therefore the P1 – BC MARKETS portfolio phases-in the Planning Margin in approximately 11% increments each year, starting in 2010.

Figures 7.4.1-A and 7.4.1-B below graphically demonstrate the P1 - BC MARKETS portfolio's closure of FortisBC's energy and capacity gaps, respectively.

Figure 7.4.1-A: P1 - BC MARKETS Energy Gap Closure

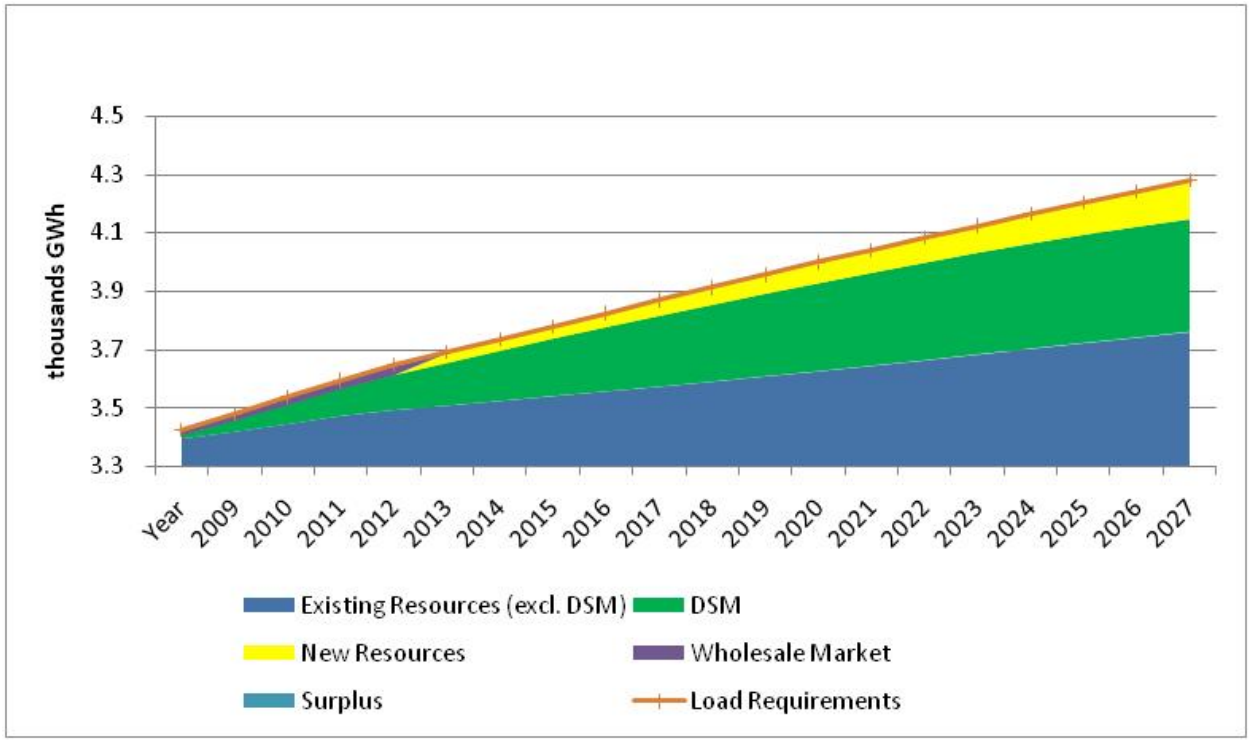
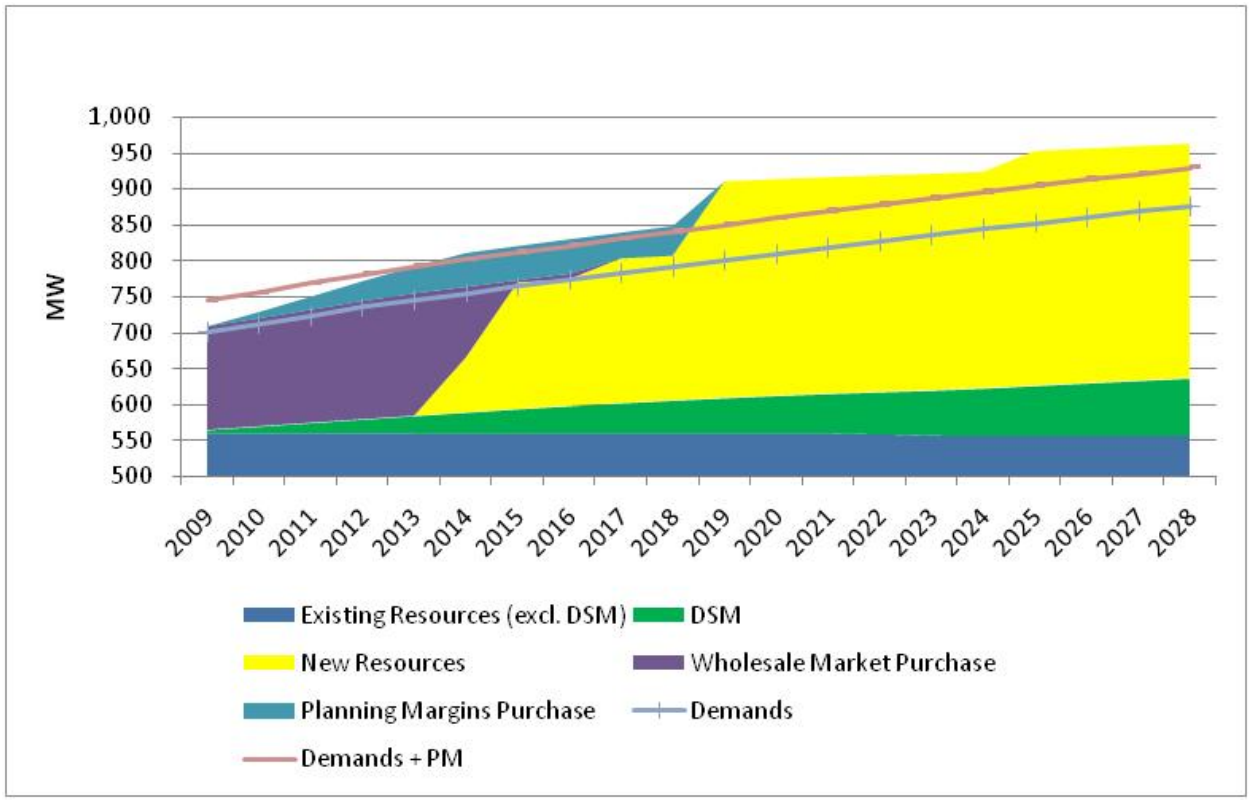


Figure 7.4.1-B: P1 - BC MARKETS Capacity Gap Closure



The P1 - BC MARKETS portfolio's performance in terms of capacity, Planning Margin and energy for select years during the planning period of this 2009 Resource Plan is demonstrated in Table 7.4.1-A below.

Table 7.4.1-A: P1 - BC MARKETS Performance Summary

Dependable Capacity (MW)	2009	2013	2014	2015	2019	2020	2021	2024	2025	2028
Forecast Gap	144.5	170.5	174.8	179.4	198.1	202.8	207.5	221.4	225.9	239.2
New Resources	0.0	0.0	76.4	176.4	225.0	225.0	225.0	225.0	250.0	250.0
Wholesale Market Purchase	144.5	170.5	98.4	3.0	0.0	0.0	0.0	0.0	0.0	0.0
Excess Capacity	0.0	0.0	0.0	0.0	26.9	22.2	17.5	3.6	24.1	10.8
Planning Margin (MW)	**2009**	**2013**	**2014**	**2015**	**2019**	**2020**	**2021**	**2024**	**2025**	**2028**
Required	44.6	46.8	47.3	47.8	49.6	50.0	50.5	51.7	52.2	53.3
New Resources	0.0	0.0	0.0	0.0	76.4	76.4	76.4	76.4	76.4	76.4
Wholesale Market Purchase	0.0	37.5	47.3	47.8	0.0	0.0	0.0	0.0	0.0	0.0
Energy (GWh)	**2009**	**2013**	**2014**	**2015**	**2019**	**2020**	**2021**	**2024**	**2025**	**2028**
Forecast Gap	18.2	33.4	35.8	38.4	58.0	63.3	70.6	90.5	99.1	130.5
New Resources	0.0	0.0	34.2	38.4	58.0	63.3	70.6	90.5	99.1	130.5
Wholesale Market Purchase	18.2	33.4	1.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Surplus	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

P2 - GAS

Prior to 2014, FortisBC would continue to rely upon the wholesale electricity market to meet its capacity and energy gaps and its requirement for a Planning Margin. In 2014, after the Simple Cycle Gas Turbines are in service, the P2 - GAS portfolio closes both the capacity and energy gaps. The 2 x 42 MW Simple Cycle Gas Turbines in 2014 operate on a standby basis in the Planning Margin role, while the 2 x 103 MW Simple Cycle Gas Turbines eliminate the capacity and peak-related energy gaps. The additional Simple Cycle Gas Turbine in 2020 continues to manage the capacity and peak-related energy gap. It appears that there will be a small capacity gap in 2027-2028 (5 MW or less), the final 2 years of the planning period of this 2009 Resource Plan. However, given the uncertainties of forecasting, it is FortisBC's opinion that it is unnecessary at this time to plan a resource for this small forecast gap.

In the P2 – GAS portfolio, a physical Planning Margin is expected to be in place by 2014, which is the earliest that it is expected that the Simple Cycle Gas Turbines required to provide the Planning Margin can be built. Therefore in order to mitigate risk prior to 2014, a market-based, interim Planning Margin is phased in at approximately 20% per year, starting in 2010.

The P2 - GAS portfolio does not provide an energy base-load resource. FortisBC recognizes that access to a large volume of energy may become necessary during the planning period of this 2009 Resource Plan, contingent upon as-yet still developing energy-use scenarios such as Plug-in Hybrid Electric Vehicles (as discussed in Section 5.3.3 above). If this were to prove to be the case, the Company would be able to convert one or more of the Simple Cycle Gas Turbines into a Combined Cycle Gas Turbine base-load plant which could provide the necessary energy.

FortisBC will continue to monitor forecast load growth, keeping potential new variables (such as the Plug-in Hybrid Electric Vehicles described in Section 5.3.3 above) in focus, and adjust resource requirements as necessary.

Figures 7.4.1-C and 7.4.1-D below graphically demonstrate the P2 – GAS portfolio's closure of FortisBC's energy and capacity gaps, respectively.

Figure 7.4.1-C: P2 - GAS Energy Gap Closure

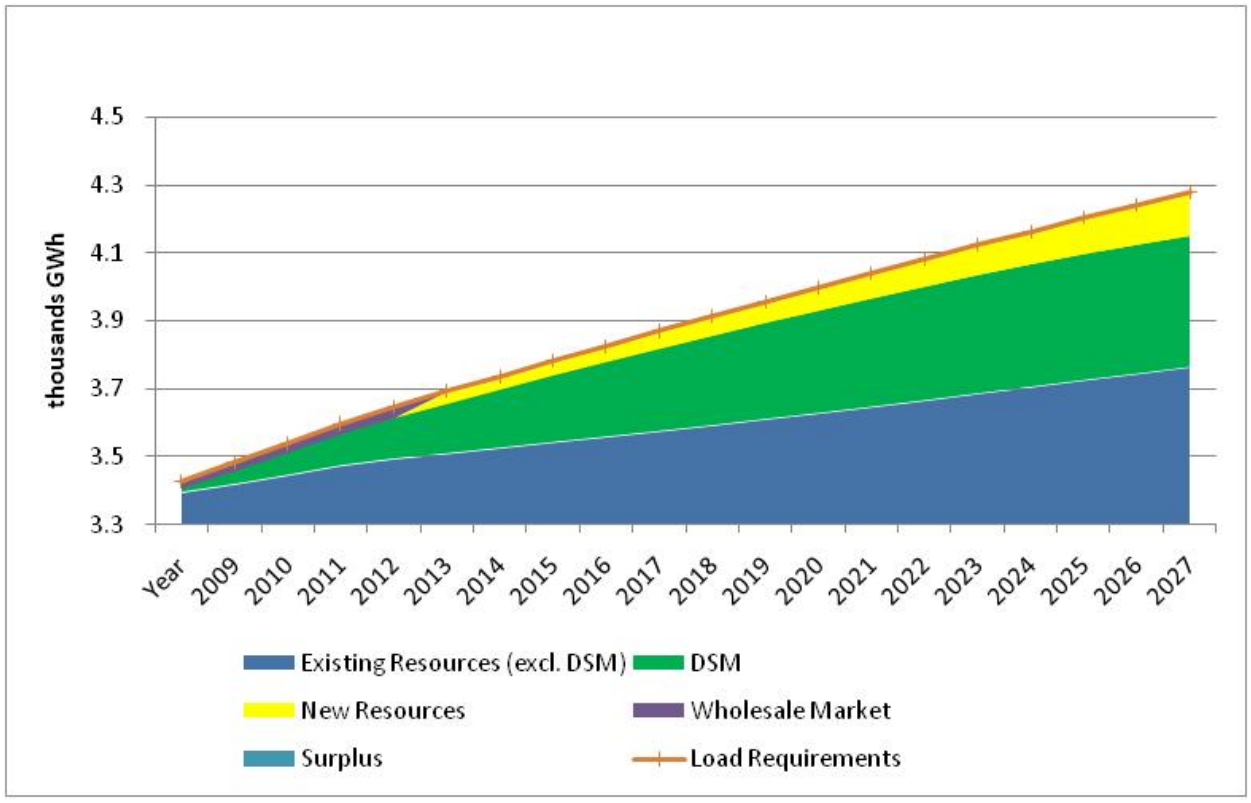
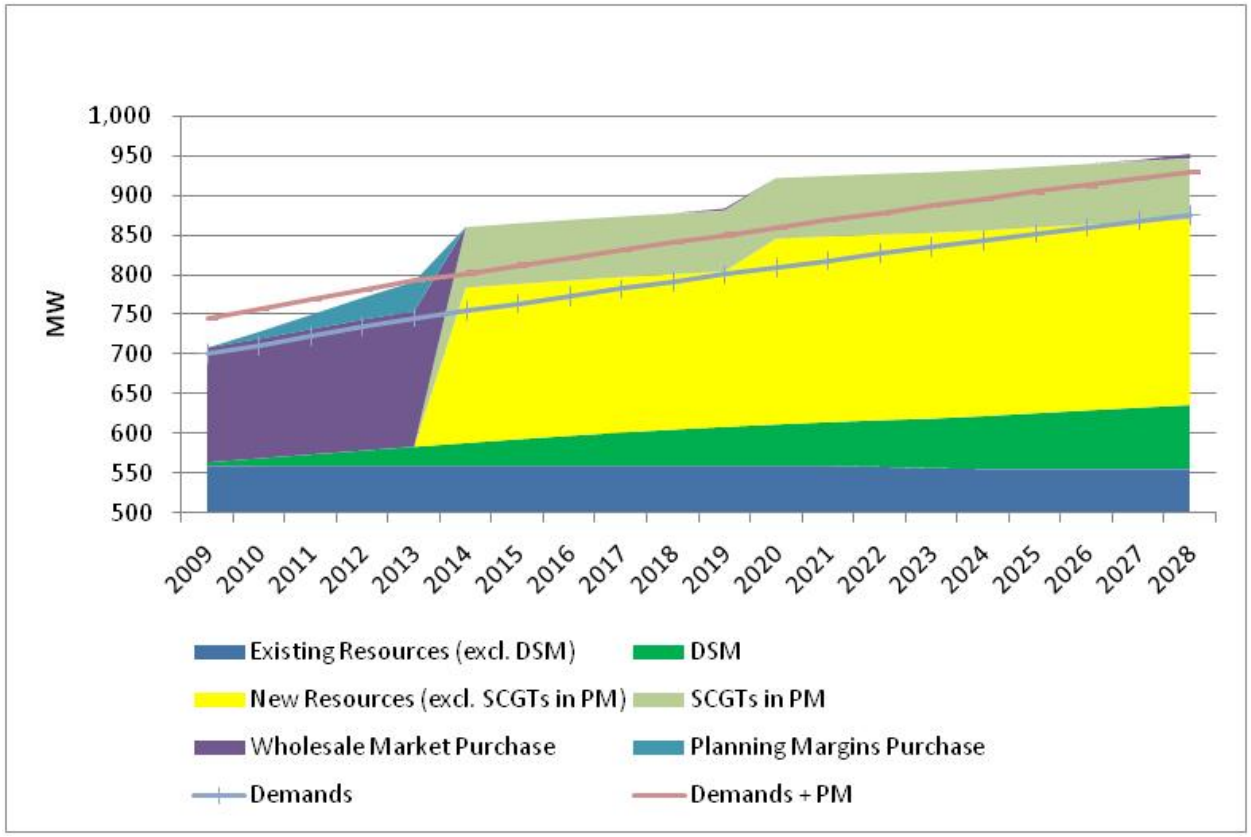


Figure 7.4.1-D: P2 - GAS Capacity Gap Closure



The P2 – GAS portfolio's performance in terms of capacity, Planning Margin and energy for select years during the planning period of this 2009 Resource Plan is demonstrated in Table 7.4.1-B below.

Table 7.4.1-B: P2 - GAS Performance Summary

Dependable Capacity (MW)	2009	2013	2014	2015	2019	2020	2026	2027	2028
Forecast Gap	144.5	170.5	174.8	179.4	198.1	202.8	230.4	234.9	239.2
New Resources	0.0	0.0	195.6	195.6	195.6	233.8	233.8	233.8	233.8
Wholesale Market Purchase	144.5	170.5	0.0	0.0	2.5	0.0	0.0	1.1	5.4
Excess Capacity	0.0	0.0	20.8	16.2	0.0	31.0	3.4	0.0	0.0
Planning Margin (MW)	**2009**	**2013**	**2014**	**2015**	**2019**	**2020**	**2026**	**2027**	**2028**
Required	44.6	46.8	47.3	47.8	49.6	50.0	52.6	53.0	53.3
New Resources	0.0	0.0	76.4	76.4	76.4	76.4	76.4	76.4	76.4
Wholesale Market Purchase	0.0	37.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Energy (GWh)	**2009**	**2013**	**2014**	**2015**	**2019**	**2020**	**2026**	**2027**	**2028**
Forecast Gap	18.2	33.4	35.8	38.4	58.0	63.3	108.2	119.2	130.5
New Resources	0.0	0.0	35.8	38.4	58.0	63.3	108.2	119.2	130.5
Wholesale Market Purchase	18.2	33.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Surplus	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

P3 – HYBRID

Prior to 2014, FortisBC would continue to rely upon the wholesale electricity market to meets its capacity and energy gaps and its requirement for a Planning Margin. In 2014, the energy gap is reduced by 95% and the capacity gap is reduced from 171 MW to 98 MW when the Simple Cycle Gas Turbines come on-line. By 2017 the capacity gap has grown again to 112 MW which the Small Hydro facility then reduces to 75 MW. The Small Hydro facility also provides 129 GWh of surplus energy for sale. In 2019 the Pumped Storage Hydro facility takes over peaking duty from the Simple Cycle Gas Turbines, eliminating the capacity gap and enabling intermittent resources at both the system level and for the Company's customers at the distributed generation level. With the Wind facility on line in 2021, excess capacity is at 37 MW and surplus energy at approximately 157 GWh. By the end of the planning period of this 2009 Resource Plan, load growth has reduced excess capacity to about 6 MW and surplus energy to about 129 GWh.

While the P3 – HYBRID portfolio contains Simple Cycle Gas Turbines that evolve from their initial peaking role into physical Planning Margin assets, FortisBC expects that it will take until 2019 before replacement peaking capacity can be built to allow this to occur. Therefore, a market-based interim Planning Margin is phased in at approximately 11% increments each year, starting in 2010, to mitigate the risk prior to 2019.

The Pumped Storage Hydro facility is a net user of energy, requiring approximately 1.3 GWh in refilling energy for every 1.0 GWh of energy production. As the Pumped Storage Hydro facility would produce energy during Heavy Load Hours to match FortisBC's peak demands, refill would take place during non-peak Light Load Hours. The refill energy would come from FortisBC's existing and new resources during

those Light Load Hours. For portfolio comparability, the P3 – HYBRID portfolio does not show this "refill" as additional load to the forecast, but does account for it in the economic analysis as fueling costs for the Pumped Storage Hydro facility.

Figures 7.4.1-E and 7.4.1-F below graphically demonstrate the P3 - HYBRID portfolio's closure of FortisBC's energy and capacity gaps, respectively. Figure 7.4.1-E also demonstrates that a portion of the new resources' energy production is being used in the refill activity for the Pumped Storage Hydro facility, while the balance of new resource energy, over load requirements, becomes surplus.

Figure 7.4.1-E: P3 - HYBRID Energy Gap Closure

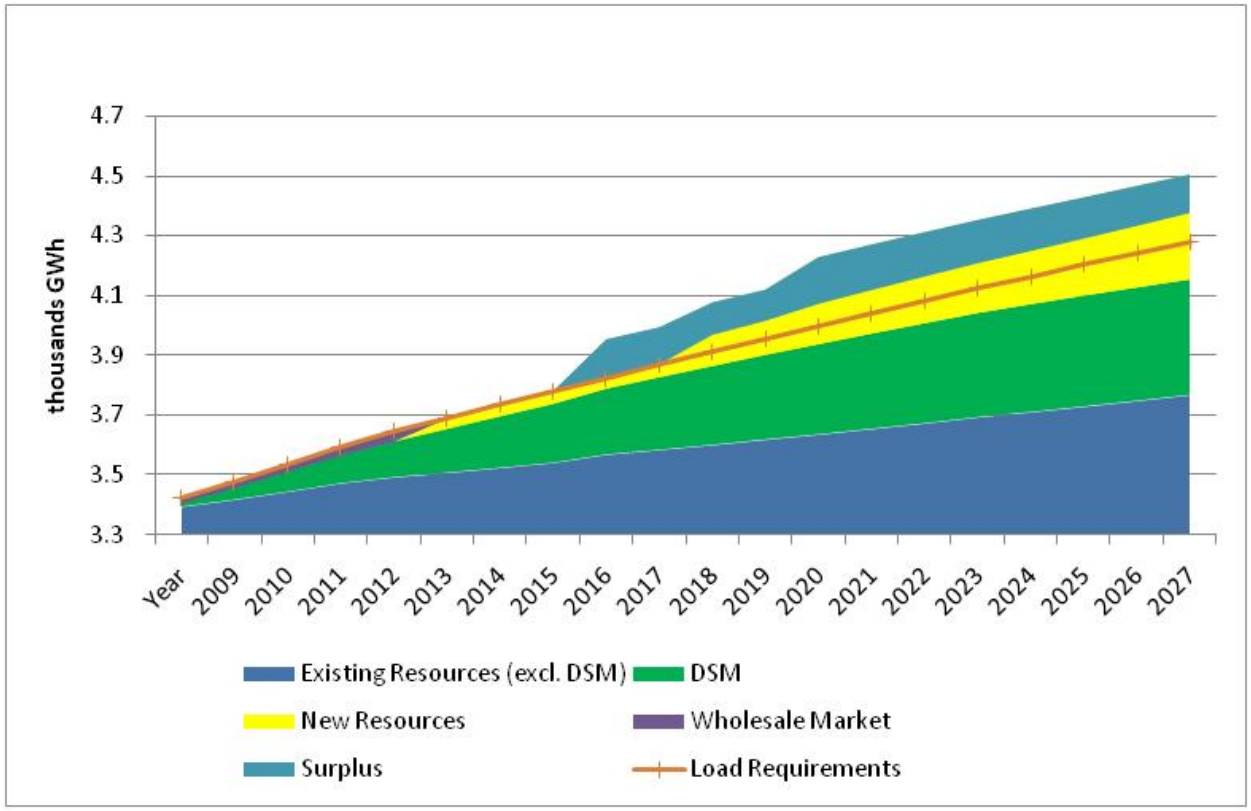
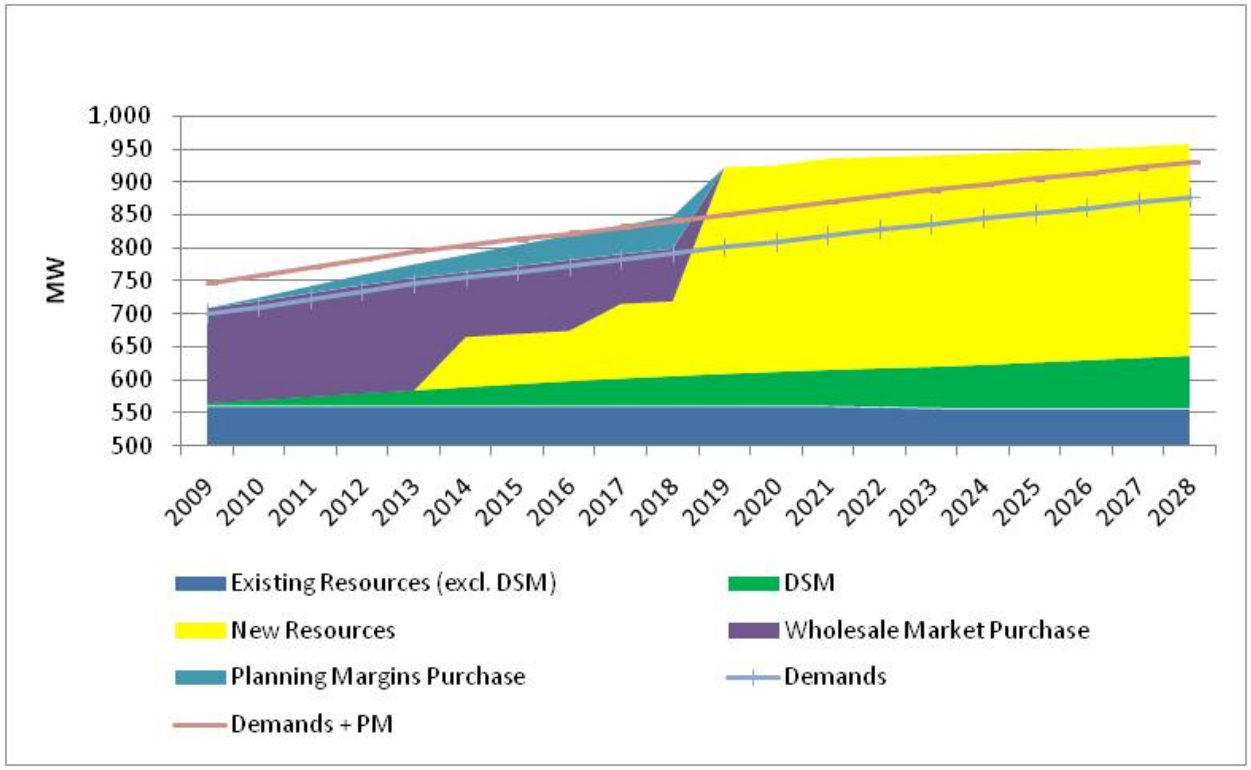


Figure 7.4.1-F: P3 - HYBRID Capacity Gap Closure



The P3 – HYBRID portfolio's performance in terms of capacity, Planning Margin and energy, including the provision for refill of the PSH, for select years during the planning period of this 2009 Resource Plan is demonstrated in Table 7.4.1-C below.

Table 7.4.1-C: P3 - HYBRID Performance Summary

Dependable Capacity (MW)	2009	2013	2014	2015	2016	2017	2018	2019	2020	2021	2027	2028
Forecast Peak Capacity Gap	144.5	170.5	174.8	179.4	184.0	188.7	193.4	198.1	202.8	207.5	234.9	239.2
SCGT	0.0	0.0	76.4	76.4	76.4	76.4	76.4	0.0	0.0	0.0	0.0	0.0
Small Hydro	0.0	0.0	0.0	0.0	0.0	37.2	37.2	37.2	37.2	37.2	37.2	37.2
PSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	200.0	200.0	200.0	200.0	200.0
Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.5	7.5	7.5
Wholesale Market Purchase	144.5	170.5	98.4	103.0	107.6	75.1	79.8	0.0	0.0	0.0	0.0	0.0
Excess Capacity	0.0	0.0	0.0	0.0	0.0	0.0	0.0	39.1	34.4	37.2	9.8	5.5
Planning Margin (MW)	**2009**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2027**	**2028**
Required	44.6	46.8	47.3	47.8	48.2	48.7	49.1	49.6	50.0	50.5	53.0	53.3
SCGT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	76.4	76.4	76.4	76.4	76.4
Wholesale Market Purchase	0.0	20.8	26.3	31.8	37.5	43.3	49.1	0.0	0.0	0.0	0.0	0.0
Energy (GWh)	**2009**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2027**	**2028**
Forecast Gap	18.2	33.4	35.8	38.4	41.4	46.5	52.1	58.0	63.3	70.6	119.2	130.5
SCGT	0.0	0.0	34.2	36.5	39.2	9.8	11.5	0.0	0.0	0.0	0.0	0.0
Small Hydro	0.0	0.0	0.0	0.0	0.0	153.8	153.8	153.8	153.8	153.8	153.8	153.8
PSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	58.0	63.3	70.6	119.2	130.5
Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	65.7	65.7	65.7
PSH Refilling energy	0.0	0.0	0.0	0.0	0.0	0.0	0.0	77.1	84.2	93.9	158.5	173.5
Wholesale Market Purchase	18.2	33.4	1.6	1.9	2.2	0.3	0.4	0.0	0.0	0.0	0.0	0.0
Surplus	0.0	0.0	0.0	0.0	0.0	(128.9)	(124.5)	(109.0)	(105.1)	(156.6)	(133.9)	(129.1)

7.4.2 Environment

What are the environmental impacts associated with each resource portfolio?

Every power generation resource has associated environmental impacts that are specific to its type and location, including in respect of land use, water use, visual impacts and emissions. Further, the transmission facilities required to move the energy output from the generation resource to the load has its own associated environmental impacts. Without knowing specific locations or specifications for new generation resources it is impossible for FortisBC to accurately predict or quantify related environmental impacts at this time. These impacts will be the subject of further, detailed investigation in connection with the requisite CPCN for any specific project.

Nevertheless, it is generally the case that the less transmission infrastructure required for a particular generation resource (the shorter the distance to be travelled from source to load), the less the transmission-related environmental impact will be. For information purposes, potential transmission-related financial costs and a preference order for new transmission infrastructure required to link new generation to load is set out in Appendix I-3.

FortisBC's ability to locate new generation in the Kelowna area will be a key determinant of environmental impacts associated with transmission infrastructure. As discussed in Section 3.9 above, FortisBC has assumed that additional transmission infrastructure will be required to support the Okanagan load center. The only resource portfolio that does not specifically contemplate the situation of new generation

resources in the Kelowna area is the P1 - BC MARKETS portfolio. Therefore, P1 - BC MARKETS is the only resource portfolio that may require additional transmission infrastructure to move the generation to the Kelowna load. As noted in Section 3.9.3 above, FortisBC estimates the cost of such infrastructure to be in the range of $70 million to $500 million+.

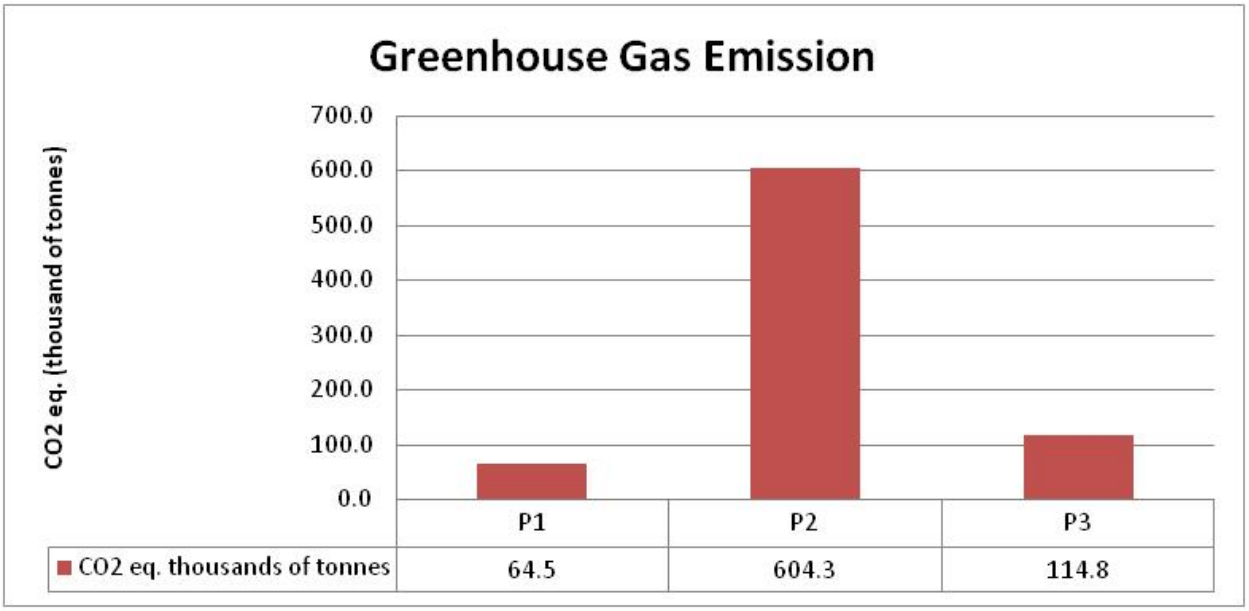
While specific environmental costs are indefinable at this time, FortisBC is able to forecast greenhouse gas emissions for each resource portfolio based upon forecast energy production and the types of generation resources involved. This information provides a proxy for portfolio environmental impact comparison purposes. Figure 7.4.2 below illustrates tonnes of greenhouse gas emissions for each resource portfolio over the planning period of this 2009 Resource Plan.

Specific greenhouse gas cost assumptions for each resource portfolio are detailed in Table 7.4.2 below.

Table 7.4.2: Detailed Portfolio Greenhouse Gas Cost Assumptions

Portfolio	Greenhouse Gas Offset Cost Assumptions
P1 - BC MARKETS	All market purchases were assessed an offset cost equivalent to that of a CCGT, with a Heat Rate of 7.24 GJ, which represents the purchased benefit of clean resources sold to the market. All power generated from the SCGTs was assessed an offset cost at Heat Rate of 9.95 GJ/MWh.
P2 – GAS	All market purchases and power generated from the CCGT were assessed an offset cost at a Heat Rate of 7.24 GJ. All power generated from the SCGTs was assessed an offset cost at Heat Rate of 9.95 GJ/MWh.
P3 – HYBRID	All market purchases were assessed an offset cost at a Heat Rate of 7.24 GJ (CCGT equivalent). All power generated from the SCGT was assessed an offset cost at Heat Rate of 9.95 GJ/MWh. No offset charges to Pumped Storage, Wind, and Small Hydro.

Figure 7.4.2: Portfolio Greenhouse Gas Emissions



The emissions analysis in Figure 7.4.2 includes emissions attributable to power supplied from the wholesale electricity market. Given the preponderance of thermal-fired production prevalent in the WECC region (both current and projected as described in Sections 3.8 and 4 above)[69], and for consistency in portfolio comparison, emissions equivalent to those produced by Combined Cycle Gas Turbines have been attributed to the supply from the wholesale electricity market supplies.

The P1 – BC MARKETS portfolio generates emissions associated with wholesale market purchases prior to new British Columbia based resources becoming available, and for the peaking plant Simple Cycle Gas Turbines modeled for the period prior to their conversion to the Planning Margin role.

The P2 – GAS portfolio generates emissions associated with wholesale market purchases prior to the new resources being in place, as well as those from the Simple Cycle Gas Turbine plants. The Simple Cycle Gas Turbines have a capacity factor growing from approximately 2.1% in 2014 to approximately 5.5% in 2028. The Simple Cycle Gas Turbines total available capacity grows from 196 MW to 234 MW over the same time frame.

The P3 – HYBRID portfolio generates emissions associated with wholesale market purchases prior to the new resources being in place, and those associated with the peaking plant operations of the Simple Cycle

[69] Approximately 57% of existing (as of January 2002) WECC generation is thermal (Figure 3.8.1-A), and 80% of new generation in the WECC region is projected to be thermal (Figure 3.8.1-B).

Gas Turbines, up until 2019. The Simple Cycle Gas Turbines have an average capacity factor of less than 1% over the planning period of this 2009 Resource Plan, with the highest capacity factor being 5.9% in 2016.

7.4.3 BC Energy Plan

How well does the resource portfolio meet policy actions set out in the BC Energy Plan?

Figure 7.4.3 below illustrates how each resource portfolio responds to the BC Energy Plan Policy Actions enumerated in Table 3.5.2.1 above. A "Y" indicates the portfolio meets the objectives of the Policy Actions, and an "N" indicates that it does not.

Figure 7.4.3: Portfolio Response to BC Energy Plan Policy actions

BC Energy Plan Category	Policy Action	P1	P2	P3
Environmental	**Policy Action 18**: All new electricty generation projects will have zero net green house gas emissions.	Y	Y	Y
	Policy Action 19: Zero net GHG from existing thermal by 2016.	Y	Y	Y
	Policy Action 20: Zero greenhouse gas emissions from coal fired electricity generation.	Y	Y	Y
	Policy Action 21: Ensure clean or renewable electricity generation continues to account for at least 90% of total generation.	Y	N	Y
Energy Security	**Policy Action 10**: Provincial self-sufficiency by 2016.	Y	Y	Y

The **P1 - BC MARKETS** portfolio does not directly contribute to provincial self-sufficiency, since FortisBC's existing capacity and energy gaps and forecast load growth must be considered as additional load that the provincial system will have to support. FortisBC is not proposing to build additional generation resources. However, this resource portfolio assumes that the additional resources will be built by some power producer in British Columbia, and therefore it is considered to meet Policy Action 10.

The **P2 - GAS** portfolio, once all new resources are operating, and after the physical Planning Margin is in place, reduces the percentage of FortisBC's total system that clean or renewable resources comprise to approximately 65% clean or renewable, if the peaking resources are rated utilizing full dependable capacity values. From this perspective the P2 – GAS portfolio fails to meet Policy Action 21. Note, however, that this does not reflect the effective capacity output from actual operation of the peaking plants which would result in the portfolio meeting the 90% goal of Policy Action 21.

The **P3 - HYBRID** portfolio meets all applicable BC Energy Plan Policy Actions. Once the Pumped Storage Hydro facility takes over peaking operations and the Simple Cycle Gas Turbines are placed on standby in the physical Planning Margin role, the Company's total generation is 100% clean or renewable. Including the Planning Margin capacity in the calculation reduces that percentage represented by clean or renewable resources to approximately 91%, which continues to meet Policy Action 21.

7.4.4 Economics

Is the resource economical?

7.4.4.1 Overview

FortisBC believes there are three distinct issues to be addressed in assessing the relative economics of the three resource portfolios.

The first involves determination of a market price forecast that reasonably predicts what capacity and energy will cost if purchased from British Columbia suppliers during the planning period of this 2009 Resource Plan. This is the foundation for the cost model for the P1 – BC MARKETS portfolio, and provides the forecast cost of the phased-in, interim, market-based Planning Margin in both the P2 – GAS and P3 – HYBRID portfolios. This topic is discussed in detail in Section 7.4.4.2 below.

The second issue is capital costs, and the timing for those, in each of the portfolios. This topic is discussed in detail in Section 7.4.4.3 below.

Finally, it is necessary to compare the costs (on a net present value basis) of all three resource portfolios, including potential variables affecting those costs. This discussion includes the relevant rate requirements associated with the costs (on a net present value basis) of each portfolio. This topic is discussed in detail in Section 7.4.4.4 below.

7.4.4.2 BC Market Capacity and Energy Costs

While the P1 - BC MARKETS portfolio appears to allow FortisBC to transfer the construction and ownership costs and risks associated with the required new generation resources to others, FortisBC has assumed that any new power purchase agreement would in fact monetize those costs and risks (together with a profit margin for the seller) and pass them through to FortisBC. The P1 - BC MARKETS portfolio is modeled in such a way as to illustrate the shaping costs of producing capacity, firm and non-firm energy, as well as potential sell-back costs of surplus energy associated with meeting FortisBC's needs through new power purchase agreements with new power supply owners. In other words, FortisBC has attempted to structure this portfolio to represent the incremental long term cost of power in British

Columbia. It is the Company's understanding that FortisBC will be required to pay "market" prices for any power produced in British Columbia that is over and above its Heritage Contract-related entitlement.

There are two key components to forecasting the cost of meeting FortisBC's needs from the British Columbia market:

(1) the cost of capacity

It is expected that new resources will have to be built within British Columbia to supply new capacity requirements. However, even if new resources do not have to be built, it is FortisBC's opinion that the Company will have to pay the market cost to access that capacity.

(2) the cost of energy

FortisBC is capacity constrained, with energy gaps associated with peak load demands. Therefore, the Company will purchase capacity products, and take energy as required during peak periods.

7.4.4.2.1 Cost of Capacity - BC Market Price

To forecast the capacity cost component, FortisBC has derived a cost of capacity market price based upon a weighted average cost of potential new capacity resources and related transmission. The reference for these potential new capacity resources is Appendix F1 of the BC Hydro 2008 LTAP, adjusted to C$2009. Table 7.4.4.2.1 below shows the capacity resources utilized, and the resultant weighted average market price for capacity. This capacity charge is assigned to all of the capacity purchased in the P1 - BC MARKETS portfolio, and is inclusive of all UCC cost components including capital, fixed and variable operation and maintenance. Note that it is FortisBC's assumption that the Company will have access to incremental capacity resources at fair market value in British Columbia. However, in its forecast of market capacity costs, additional Resource Smart resources (such as new Mica or Revelstoke units) were excluded from the capacity cost weighted average calculation. In the Company's opinion, access to those resources would not be on an incremental cost basis and, therefore, inclusion of these Resource Smart supply options (with the UCC values assigned them in the BC Hydro 2008 LTAP) would skew the market cost forecast.

Table 7.4.4.2.1: P1 - BC MARKETS Cost of New Capacity

Capacity Option	Dependable Capacity (MW)	BCH 2008 LTAP Appendix F1 Reference Page #	UCC @ 8% ($/MW per Month)	Weighted Portion of UCC @ 8% ($/MW per Month)
Kelly Lake SCGT (42 MW)	38	11	$ 9,750	$ 300.24
Kelly Lake SCGT (103 MW)	98	12	$ 6,083	$ 483.09
Lower Mainland SCGT (103 MW)	98	27	$ 8,750	$ 694.89
Pumped Storage - Lower Mainland	1,000	7	$ 12,167	$ 9,859.81
Total Bundle	**1,234**	**Weighted Average of Bundle**		**$ 11,338.03**

Reference: BC Hydro 2008 Long Term Acquisition Plan, Appendix F1

Transmission Addition to Capacity Costs	
BCTC Long and Short-Term Firm Point-to-Point Transmission, $/MW per Month	**4,120.00**
Total Capacity Cost Charge	**15,458.03**

The cost of capacity from the British Columbia market, as described above, applies to both the P2 – GAS and P3 – HYBRID portfolios relative to the pricing of the phased-in, interim, market-based Planning Margin in place in both portfolios until such time as a physical Planning Margin is available. In the P2 – GAS portfolio - this covers the period 2010-2014. In the P3 – HYBRID portfolio this covers the period 2010-2019.

7.4.4.2.2 Cost of Energy – BC Market Price

To forecast the energy cost component, FortisBC again initially referred to the BC Hydro 2008 LTAP Appendix F1 to compile a number of energy resources. From the UEC values listed for those resources the capital and fixed operation and maintenance costs were removed to leave a cost for the energy based upon the variable cost components associated with the production of that energy. All fixed costs related to the energy purchased in the P1 – BC MARKETS portfolio are incorporated in the capacity cost forecast noted above. Table 7.4.4.2.2-A below shows the list of resources used, their energy cost based upon variable production cost elements, and the resultant average cost of energy in C$2009. Note that for the Wind resources listed below, the full UEC values (based upon average annual energy production), attributed to them in BC Hydro's 2008 LTAP were utilized since the Appendix F1 UEC data did not provide specific fixed costs in their calculation, and therefore there was no basis for removal of fixed costs from the UEC cost of energy indicated.

Table 7.4.4.2.2-A: Average Energy Cost for P1 - BC MARKETS

Source Type	Reference - BCH 2008 LTAP, App F1, Page #	Average Cost ($/MWh) (reference cost + 2% = C$2009)
Combined Cycle Gas Turbine (CCGT) 50 MW	8	$95
Small Co-Gen	13	$86
BioGas	30	$36
Municpal Waste	31	$53
Simple Cycle Gas Turbine (SCGT) 40 MW	62	$119
SCGT 100 MW	64	$112
Wind (Lower Mainland / Nicola)	197	$128
Wind (East Kootenay)	215	$157
	Average	$98.25

FortisBC has used this preliminary cost of energy ($98.25 per MWh) as the base for forecasting the cost of energy in the P1 – BC MARKETS portfolio through the planning period of this 2009 Resource Plan. Table 7.4.4.2.2-B below completes the forecast for the cost of energy in the British Columbia market by adding a greenhouse gas-related cost component (Column 2). It is FortisBC's expectation that there will be a greenhouse gas-related cost component either directly related to emissions from potential thermal generating resources, or as a result of a clean generating resource's clean attributes being monetized in a power purchase agreement.

Table 7.4.4.2.2-B: P1 - BC MARKETS Cost of Energy Forecast

Year	1. BC Market Average Cost of Energy	2. GHG Adder $/MWh (equivalent to BC Carbon Tax)	FortisBC BC Market Cost of Energy Forecast $/MWh (1+2)
2009	$98.25	$4.40	$102.65
2010	$100.22	$6.03	$106.25
2011	$102.22	$7.61	$109.82
2012	$104.26	$9.11	$113.37
2013	$106.35	$9.74	$116.09
2014	$108.48	$9.74	$118.22
2015	$110.65	$9.74	$120.39
2016	$112.86	$9.74	$122.60
2017	$115.12	$9.74	$124.86
2018	$117.42	$9.74	$127.16
2019	$119.77	$9.74	$129.51
2020	$122.16	$9.74	$131.91
2021	$124.60	$9.74	$134.35
2022	$127.10	$9.74	$136.84
2023	$129.64	$9.74	$139.38
2024	$132.23	$9.74	$141.98
2025	$134.88	$9.74	$144.62
2026	$137.57	$9.74	$147.32
2027	$140.33	$9.74	$150.07
2028	$143.13	$9.74	$152.88

FortisBC applied the resultant cost of energy to all energy requirements in the P1 – BC MARKETS portfolio.

7.4.4.3 Capital Costs

While the P1 - BC MARKETS portfolio assumes that the British Columbia market will supply capacity and energy through new power purchase agreements, it does not avoid all direct capital costs. Given that the P1 - BC MARKETS portfolio does not envision new generation in the Kelowna area, it would require additional transmission infrastructure to move the generation to the Kelowna load. This cost is estimated to be in the range $70 million to $500 million+. FortisBC has not defined a specific solution for this at this time, so is unable to include these costs in the economic evaluation of the P1 - BC MARKETS portfolio. However, there are approximately $43 million of unavoidable transmission upgrade capital costs associated with the P1 - BC MARKETS portfolio. The timing, type, and amount of these costs are as follows:

Table 7.4.4.3-A: P1 - BC MARKETS - Capital Cost Schedule

P1 - BC MARKETS	Year in Service	Capital Cost (C$2009 million)
SVC	2013	$35.0
Vaseux Transformer	2016	$8.0
Total		**$43.0**

Both the P2 – GAS and P3 – HYBRID portfolios assume new generation resources in FortisBC's North Okanagan service territory within the time frame necessary to avoid the transmission-related capital costs set out in Table 7.4.4.3-A.

The P2 – GAS resource portfolio assumes the acquisition of four Simple Cycle Gas Turbine units in 2014 and another Simple Cycle Gas Turbine unit in 2020. The capital costs associated with these acquisitions in the P2 – GAS portfolio (resource and timings) are set out in Table 7.4.4.3-B below:

Table 7.4.4.3-B: P2 - GAS Capital Cost Schedule

P2 - GAS	Year in Service	Capital Cost (C$2009 million)
Simple Cycle Gas Turbine (SCGT)	2014	$230.0
SCGT	2020	$44.0
Total		**$274.0**

The P3 – HYBRID portfolio assumes the acquisition of two Simple Cycle Gas Turbine units in 2014, the construction of a Small Hydro facility by 2017 and a Pumped Storage Hydro facility by 2019. In 2021 a clean energy resource is added, which is modeled as an "acquired" Wind resource. However, both the type of clean resource and determination as to whether it is a FortisBC-owned resource or a third party resource the output of which is provided pursuant to a power purchase agreement remains to be determined. The capital cost associated with these acquisitions (resource and timings) are set out in Table 7.4.4.3-C below:

Table 7.4.4.3-C: P3 - HYBRID Capital Cost Schedule

P3 - HYBRID	Year in Service	Capital Cost (C$2009 million)
Simple Cycle Gas Turbine (SCGT)	2014	$88.0
Small Hydro with Capacity	2017	$148.0
Pumped Storage Hydro (PSH)	2019	$510.0
Wind	2021	$63.0
Total		**$809.0**

7.4.4.4 Net Present Value Calculations and Associated Rate Requirements

Table 7.4.4.4 below presents a summary of the portfolio cost elements that make up the Net Present Value comparison. In Table 7.4.4.4:

- **Column A** (Cost for Market Purchase) sets out only those costs related to purchases from the wholesale electricity market. These are assumed in each portfolio for the period prior to new resources or new power purchase agreements being in place.

- **Column B** (Power Cost for New Resources)

  - The P1 – BC MARKETS portfolio includes all British Columbia-based market costs for capacity, energy, and Planning Margin as discussed in Section 7.4.4.2 above. Related variable operation and maintenance, fuel, and greenhouse gas-related costs are included in the British Columbia-market cost forecast.

  - The P2 – GAS and P3 – HYBRID portfolios include variable operation and maintenance, fuel and greenhouse gas-related costs.

    - Both portfolios include Simple Cycle Gas Turbines which are natural gas fueled, creating natural gas price risk.

    - The P2 – GAS portfolio relies exclusively on natural gas to fuel FortisBC's requirements for capacity and energy. While this avoids an electricity market price risk, it does create natural gas price risk. In general, the volatility of electricity prices noted in Section 4.1.1 above is closely related to volatility in natural gas prices. However, given the P2 – GAS portfolio's low capacity factor (ranging from 2.1% to 5.5%), it will have unused capacity during periods of high market demand, allowing for opportunity to sell electricity to the market. The resulting profits may offset any higher than average gas price experienced during periods of market volatility. Secondly, there is an existing market for longer term natural gas purchases making it possible to hedge natural gas prices which may reduce the overall volatility of natural gas costs. The low capacity factor, the potential arbitrage opportunity, and the hedging opportunity all serve to mitigate the gas price risk.

    - The P3 – HYBRID portfolio's exposure is substantially less given that the two Simple Cycle Gas Turbine units in the portfolio run in peaking operations only from 2014 to 2018, and have an average capacity factor of less than 1%. In

addition, the mitigating factors noted above also apply to the P3 – HYBRID portfolio.

- Barring unpredictable sales opportunities related to running the Simple Cycle Gas Turbines in the P2 – GAS portfolio, the only portfolio that envisions surplus sales is the P3 – HYBRID portfolio. The projected revenue is based upon the forecast price for surplus sales shown in Table 7.4.4.4, and denoted below in **Column C**. The P3 – HYBRID portfolio does not include potential sales from its Simple Cycle Gas Turbines operating in excess of peaking requirements, and the surplus volume from other resources is reduced by the requirements for refilling the Pumped Storage Hydro facility during Light Load Hours.

- **Column D** captures the capital related costs of depreciation, carrying costs, and income tax as they relate to the capital investments envisioned for each portfolio.

- In all portfolios there is a time period prior to a physical Planning Margin being available for service. During that time frame FortisBC has modeled a phased-in, interim, market-based Planning Margin which is priced using the BC-market cost of capacity set out in Section 7.4.4.2.1 above. For comparison purposes, **Column E** keeps the Net Present Value of those market-based interim Planning Margins separate from other cost components.

- **Column F** totals Columns A through E for each portfolio.

Table 7.4.4.4: Portfolio Cost Elements

Portfolio Cost Elements (NPV @8% in $2009 millions)	A	B	C	D	E	F		
Portfolio	Cost for Market Purchases	Power Cost for New Resources	Surplus Energy Sales	Capital Related Cost	Planning Margin	Total	Average Annual Rate Impact	20 Year Cumulative Rate Impact
P1 - BC MARKETS	$7.6	$311.3	$0.0	$24.9	$12.8	**$356.6**	1.12%	24.65%
P2 - GAS	$7.5	$51.6	$0.0	$143.8	$9.0	**$211.9**	0.66%	13.54%
P3 - HYBRID	$7.8	$61.3	($31.8)	$272.7	$11.8	**$321.9**	1.18%	25.75%

Column A - cost of purchasing capacity and energy from the wholesale electricity market prior to new portfolio resources coming on-line.
Column B - represents the costs associated with power production, including variable O&M, fuel, and GHG-related costs. In P1 - BC MARKETS this includes both the cost of capacity and cost of energy, as discussed in Section 7.3.5.2.. For P3 - HYBRID this includes the refill costs associated with the PSH, as discussed in Section 7.3.1.
Column C - represents potential surplus sales revenues, based upon the forecast in Table 7.6.
Column D - represents all rate requirement capital-related costs associated with new capital investment.
Column E - represents the cost associated with the market-based interim Planning Margin product purchased prior to a portfolio having a physical Planning Margin in place.
Column F is the total of Columns A through E

Table 7.4.4.4 also sets out each portfolio's average annual rate impact and 20 year cumulative rate impact.

It must be noted that while Table 7.4.4.4 provides a reasonable cost comparison (on a net present value basis) between the portfolios, it is not all-inclusive. In other words, while FortisBC is aware that potentially significant transmission infrastructure additions will be required during the planning period to support the growing load in its North Okanagan service territory, it is unable to definitely quantify the cost of those additions at this time. As stated previously, the P3- HYBRID and P2 – GAS portfolios intend to locate new generation resources in the Kelowna area which would defer or eliminate the construction of any such required new transmission. The P1 – BC MARKETS portfolio does not envision locating new generation in the Kelowna area. Therefore, while a quantitative analysis is unavailable at this time, the potential economic impact of the new transmission infrastructure must be taken into account when weighing the relative economics of each portfolio.

7.4.5 Stakeholder Consultation

FortisBC considered it important to try to determine its customers' priorities with respect to what type of resourcing strategy those customers might support. As one would expect, there are many and varied opinions on the subject and it is difficult to draw definite conclusions. The different consultation techniques FortisBC employed included simple telephone surveys and fully structured workshops where customers were briefed on the various issues and options. Despite the expected varied reactions, the following themes were prevalent:

- conservation should be considered first
- environmentally sound solutions are important
- transmission impacts are of concern
- incremental cost is of concern
- lessening dependence on external resources, especially United States markets is favoured.

Subsequent to filing, FortisBC intends to present this 2009 Resource Plan to interested customers through a series of open houses within its service territory. Notification of the open houses will be published in area newspapers. FortisBC also intends to engage in additional stakeholder consultation, and will file a report summarizing the open houses and all such other stakeholder consultation efforts as part of the regulatory process.

FortisBC will continue to ensure that this 2009 Resource Plan reflects its customers' input.

7.4.6 Decision Matrix

The selection of a preferred resource strategy chosen from amongst the portfolios analyzed is a complex one. The issues and selection criteria are complex and interrelated. In such a situation, a Decision Matrix is of assistance in determining the solution that optimally balances competing criteria. It should be noted that the Decision Matrix does not presuppose a stakeholder preference.

The Decision Matrix is set out below in Table 7.4.6 below.

- The lower the score, the better the rating.
- All four selection criteria are weighted equally with a range from 1 to 6. Total possible range is "4" to "24" as follows.

7.4.6.1 Criterion A — Gap Closure and Planning Margin

- This weighs each portfolio's ability to close FortisBC's existing and forecast gaps in capacity, energy, and Planning Margin.
- All three portfolios meet these requirements. However there are qualitative differences:
  - The P1 – BC MARKETS portfolio closes all gaps by 2017 and provides a Planning Margin by 2019. However, the P1 – BC MARKETS portfolio vests control of generating resources in third party vendors, limiting FortisBC's long

term control over those resources, and creating potential contractual or commercial risks. This lack of ownership introduces some uncertainty as to the long term availability of these resources. **The P1 – BC MARKETS portfolio scores 3.**

- The P2 – GAS portfolio closes all gaps and provides a Planning Margin by 2014. **The P2 – GAS portfolio scores 1.**

- The P3 – HYBRID portfolio closes all gaps and provides a Planning Margin by 2019. **The P3 – HYBRID portfolio scores 2.**

7.4.6.2 Criterion B — Environment

- This weighs the portfolio's ability to avoid additional transmission infrastructure to support the growing Kelowna load, and ranks its relative greenhouse gas emissions.

- The P1 – BC MARKETS portfolio has the lowest forecast emissions. However, the P1 – BC MARKETS portfolio is the only portfolio that does not envision locating new generating resources in the Kelowna area, thereby failing to avoid construction of potentially significant additional transmission infrastructure required to support the growing Kelowna load. **The P1 – BC MARKETS portfolio scores 5.**

- The P2 – GAS portfolio has the highest forecast emissions, but does plan to defer or eliminate the Kelowna area transmission reinforcement by locating new generation resources in the Kelowna area. **The P2 – GAS portfolio scores 5.**

- The P3 – HYBRID portfolio's forecast emissions is second lowest of the portfolios, and very close to those forecast in the P1 – BC MARKETS portfolio. It also plans to defer or eliminate the Kelowna area transmission reinforcement by locating new generation resources in the Kelowna area. **The P3 – HYBRID portfolio scores 2.**

7.4.6.3 Criterion C — BC Energy Plan

- This weighs the portfolio's ability to meet the BC Energy Plan Policy Actions noted in Figure 7.4.3.

- Both the P1 – BC MARKETS portfolio and the P3 – HYBRID portfolio satisfy all noted BC Energy Plan Policy Actions. **They each score 1.**

- The P2 – GAS portfolio satisfies Policy Action 10, and the (environmental-related) Policy Actions 18, 19 and 20. It does not satisfy Policy Action 21 from the perspective of using dependable capacity when calculating the overall percentage of clean resources in the Company's resource stack. **The P2 – GAS portfolio scores 2.**

7.4.6.4 Criterion D — Economics

- This weighs the portfolios in terms of their total cost (on a net present value basis) and their planning period cumulative rate impact.

- The P2 – GAS portfolio is the "least cost" portfolio from the economic perspective inclusive of the gas-price fuel risk noted and discussed in Section 7.4.1. **The P2 – GAS portfolio scores 1.**

- The net present value and rate requirements output are similar for the P1 – BC MARKETS portfolio and the P3 HYBRID, P1 – BC MARKETS portfolio reflects FortisBC's forecast for market priced capacity and energy in BC, and that, from the net present value perspective, it will be relatively more costly for FortisBC to satisfy its existing and forecast gaps through that market. Further, while the net present value and rate requirements for the P1 – BC MARKETS portfolio do not include any quantitative provision for the cost of the transmission infrastructure additions necessary to support the Kelowna area, these must be a consideration in the overall economic assessment. **The P1 – BC MARKETS portfolio scores 4**.

- **The P3 – HYBRID portfolio scores 2.**

Table 7.4.6 below presents the Decision Matrix.

Table 7.4.6: Decision Matrix

Criteria Possible Total 4 - 24. "4" is Best; "24" is Worst	Portfolio P1 - BC MARKETS	P2 - GAS	P3 - HYBRID
A) Gap Closure + Planning Margin	3.0	1.0	2.0
B) Environment	5.0	5.0	2.0
C) BC Energy Plan	1.0	2.0	1.0
D) Economics	4.0	1.0	2.0
Total of A + B + C + D =	13.0	9.0	7.0

Decision Matrix Legend

First =	
Second =	
Last =	

8 PREFERRED RESOURCE STRATEGY

8.1 Selection of Preferred Resource Strategy

The P2 – GAS portfolio is the portfolio having the lowest cost (on a net present value basis) and the lowest cumulative rate impact. However, the P2 – GAS portfolio is also expected to produce approximately 604 thousand tonnes of greenhouse gas emissions over the planning period of this 2009 Resource Plan, roughly 525% that of the P3 – HYBRID portfolio and 930% that of the P1 – BC MARKETS portfolio. In FortisBC's opinion, therefore, despite its economic performance, the P2 – GAS portfolio is not the most optimal long term solution for the Company.

The P1 – BC MARKETS and P3 – HYBRID portfolios have roughly the same economics and perform similarly in meeting the objectives of the BC Energy Plan. There are several key differences, however, as follows:

1. The P3 – HYBRID portfolio contemplates the location of new power generation resources in the North Okanagan area and in doing so defers or eliminates the need for potentially significant transmission infrastructure reinforcement to support the growing load in the area. The P1 – BC MARKETS portfolio does not similarly offer this benefit.

2. The P1 – BC MARKETS portfolio contemplates availability of power at market prices. The P3 – HYBRID portfolio contemplates availability of power at its cost.

3. The P3 – HYBRID portfolio contemplates FortisBC's ownership and control of new resources, with attendant benefits for both FortisBC and its customers. Currently, approximately 68% of FortisBC's existing capacity resources derive from power purchase agreements with third parties. The P1 – BC MARKETS portfolio increases to approximately 75% that exposure to contractual risk, exacerbating the Company's dependence upon third parties. The P3 – HYBRID portfolio reduces the Company's exposure to contractual risk to approximately 37% as a result of FortisBC's ownership of new power generation resources.

The P3 – HYBRID portfolio is, in FortisBC's opinion, a balanced solution to the Company's forecast capacity and energy gaps. It represents the resource portfolio that, through implementation of a blend of available technologies, provides the best solution in terms of environmental protection, operating flexibility and long term generation capacity sustainability. **Consequently, the P3 – HYBRID is FortisBC's preferred resource strategy**.

The P3 – HYBRID portfolio contemplates the acquisition of resources as follows:

- 2014 - 2 x 42 MW Simple Cycle Gas Turbines to provide peak capacity support and to provide transmission support to the North Okanagan region. When no longer needed in the peak capacity support role (after the Pumped Storage Hydro comes on line) these facilities would be placed on standby in the Planning Margin role while continuing to provide transmission support.

- 2017 - 40 MW Small Hydro with Capacity.

- 2019 - 200 MW Pumped Storage Hydro facility to take over the peaking role from the Simple Cycle Gas Turbines and allow for storage to support both customer-owned and other system intermittent renewables such as Wind.

- 2021 - 30 MW of Clean Resource. Such a resource might be Wind (which FortisBC has used for modeling purposes) but could include other forms of clean power.

Sections 8.2 through 8.7 below discuss the P3 – HYBRID portfolio as FortisBC's preferred resource strategy in terms of its ability to satisfy the following criteria:

1. Does the preferred resource strategy provide complete coverage of FortisBC's forecast energy and capacity gaps, after application of DSM, and does it include a Planning Margin?

2. Does the preferred resource strategy minimize environment impacts?

3. Does the preferred resource strategy meet all of the applicable policy actions of the BC Energy Plan (see Table 3.5.2.1)?

4. Is the preferred resource strategy economical?

8.2 Capacity, Energy and Planning Margin

In 2014, FortisBC's energy supply / demand gap is reduced by 95% and its capacity supply / demand gap is reduced from 171 MW to 98 MW when the Simple Cycle Gas Turbines come on-line. By 2017 the capacity gap has grown again to 112 MW, which the Small Hydro facility then reduces to 75 MW. The Small Hydro facility also provides 129 GWh of surplus energy for sale to the market. In 2019 the Pumped Storage Hydro facility takes over peaking duty from the Simple Cycle Gas Turbines, eliminating the capacity supply / demand gap and enabling introduction of intermittent resources at both the system level and for the Company's customers at the distributed generation level. With the Wind facility on line in 2021, excess capacity is at 37 MW and surplus energy is at approximately 157 GWh. By the end of the

planning period of this 2009 Resource Plan, load growth has reduced excess capacity to about 6 MW and surplus energy to about 129 GWh.

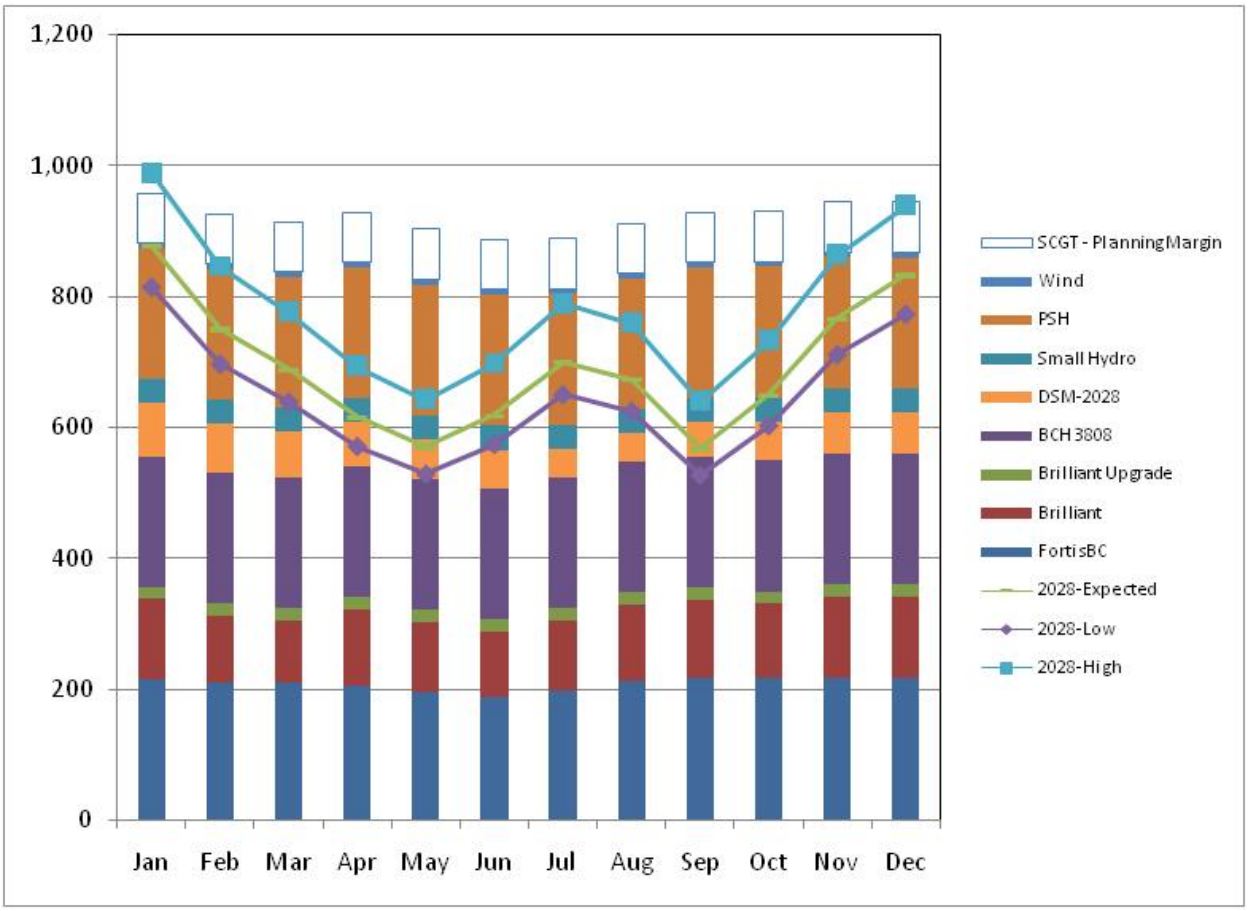
8.2.1 Monthly Capacity Requirements in 2028

From a monthly capacity requirement perspective, Figure 8.2.1 below illustrates the placing of FortisBC's existing and (P3 – HYBRID portfolio) new resources against the forecast 2028 High, Expected and Low monthly capacity requirement.

In Figure 8.2.1, the bottom end of the monthly bars represents FortisBC's existing resources (blue to purple sections of the bar show FortisBC-owned resources and existing power purchase agreements). Expected DSM contribution is shown next, followed by the new P3 - HYBRID portfolio resources of Small Hydro, Pumped Storage Hydro and Clean (represented by Wind). At the top of each monthly stack are the Simple Cycle Gas Turbines which in 2028 are operating in the standby Planning Margin role. Superimposed over the monthly capacity resources are lines representing the Low, Expected, and High peak forecasts for each month.

Figure 8.2.1 demonstrates that while the P3 – HYBRID portfolio plans for the Expected forecast, the resources selected provide sufficient flexibility to deal with the full range of the possible forecast.

Figure 8.2.1: Preferred Resource Strategy – Monthly Capacity Load/Resource Balance



8.2.2 Load Sensitivity

As noted above, FortisBC is planning to meet its "Expected" load forecast. However, the P3 - HYBRID portfolio provides sufficient flexibility to deal with load variations within the forecast low to high possibilities as demonstrated on a monthly basis in Figure 8.2.1 above. If load growth (net of DSM measures) is less than expected (approaching the "low" forecast), the P3 - HYBRID portfolio provides FortisBC with the option of delaying resource implementation dates. If load growth (net of DSM measures) is greater than expected (approaching the "high" forecast), the P3 - HYBRID portfolio provides the Company with at least the following options:

- the Pumped Storage Hydro facility could be run with a higher capacity factor;
- the Pumped Storage Hydro facility could be increased in size, either by implementing a larger first unit or adding a second unit; or

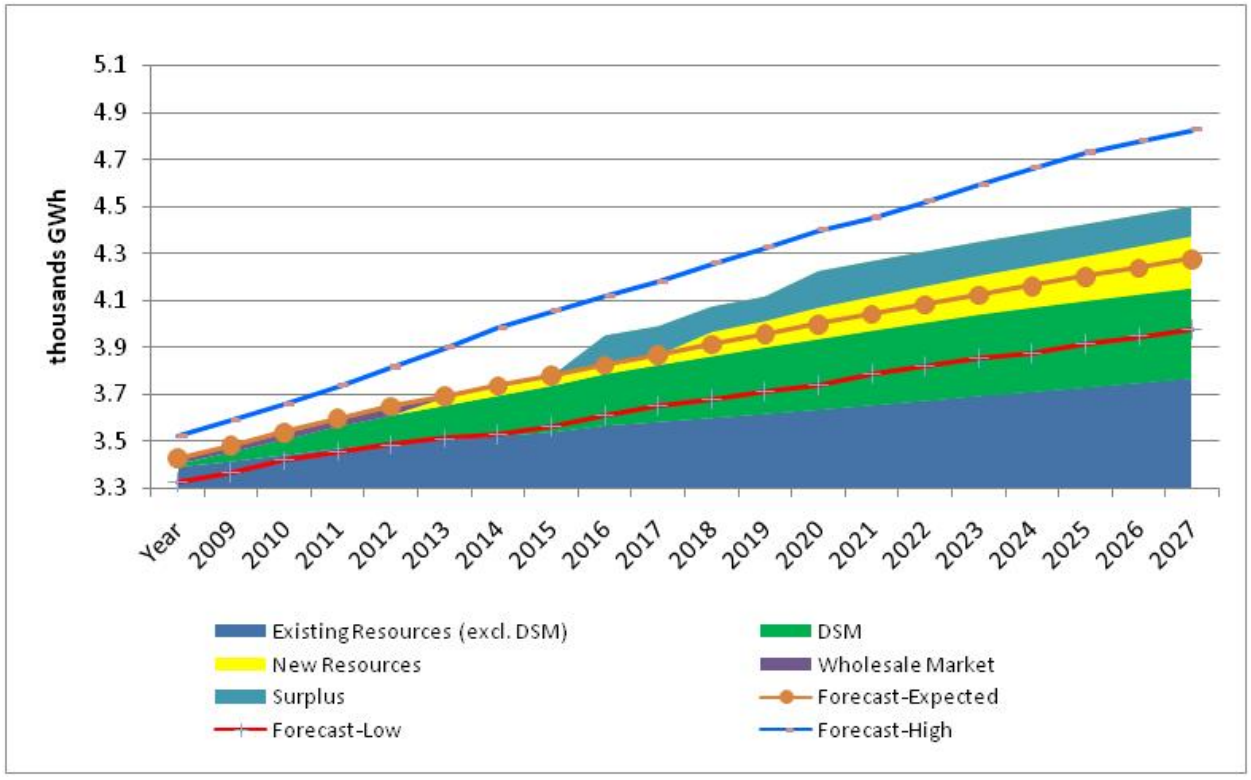
- the Simple Cycle Gas Turbines could provide additional support as required.

If there is a greater requirement for energy – in excess of the primarily peak-related energy indicated in the existing forecast – the P3 - HYBRID portfolio provides the option of converting the Simple Cycle Gas Turbines to Combined Cycle Gas Turbine base-load plants.

8.2.3 Preferred Resource Strategy Load / Resource Balance

Figures 8.2.3-A and 8.2.3-B below provide graphical representations of the P3 – HYBRID portfolio's ability to meet both energy and capacity growth for High, Expected and Low forecasts over the planning period of this 2009 Resource Plan.

Figure 8.2.3-A: Preferred Resource Strategy – Energy Load / Resource Balance

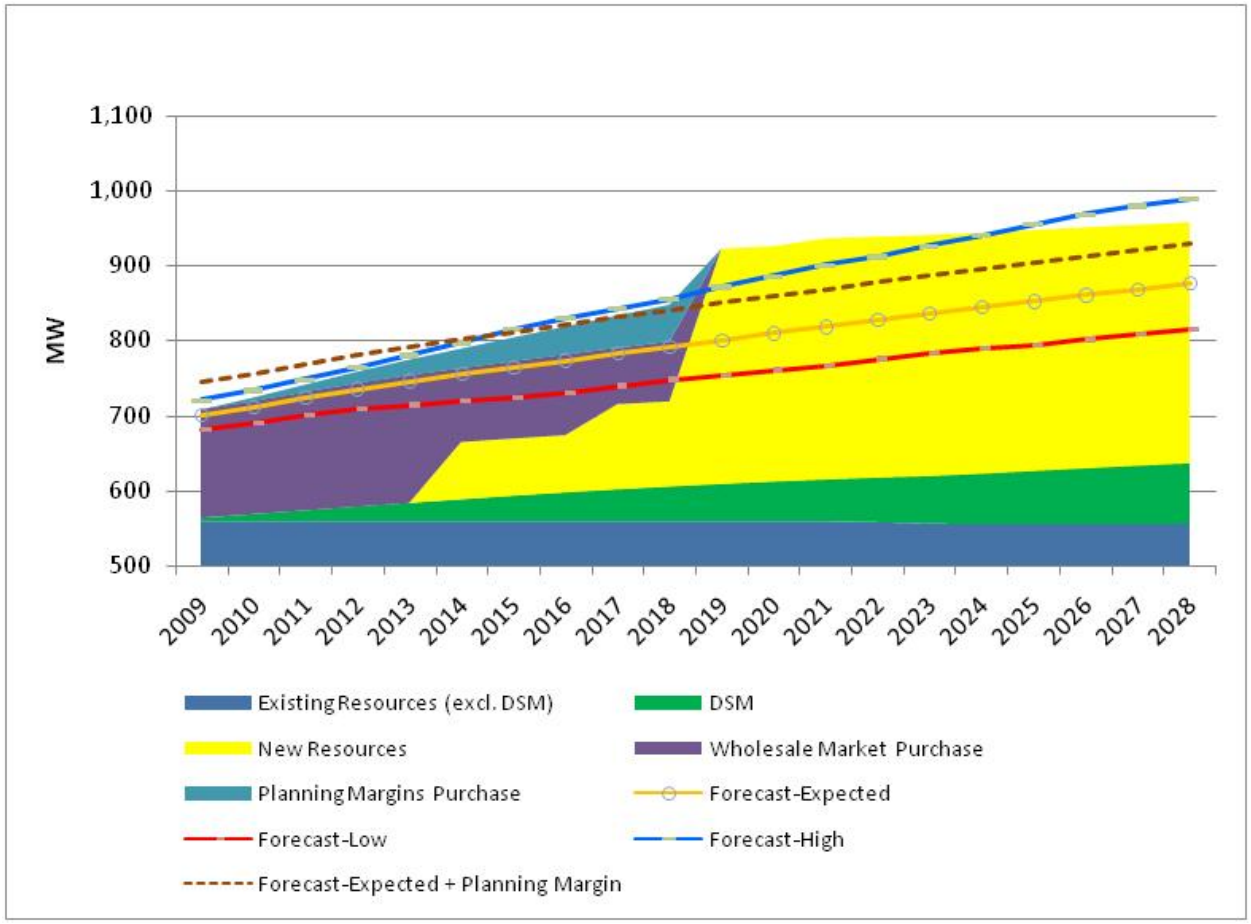


The Pumped Storage Hydro facility would be a net user of energy, requiring approximately 1.3 GWh in refilling energy for every 1.0 GWh of energy production. As the Pumped Storage Hydro facility would produce energy during Heavy Load Hours to match FortisBC's peak demands, refilling would take place during non-peak Light Load Hours. The refill energy would come primarily from FortisBC's existing and new clean renewable resources during those Light Load Hours. Figure 8.2.3-A above demonstrates that,

after satisfying the forecast load, a portion of new resource energy goes to refill, with the balance becoming surplus.

Figure 8.2.3-B below demonstrates how the P3 - HYBRID portfolio deals with the capacity supply / demand gap over the planning period of this 2009 Resource Plan. The Low, Expected and High peak capacity forecasts are displayed by the red, orange, and blue lines, respectively. Until new resources start to come on line in 2014, the capacity supply / demand gap is covered by DSM and market purchases (green and purple areas). From 2014 until 2019, as new resources are introduced (the yellow area) the peak capacity gap is reduced and then finally eliminated. The blue area represents the market-based interim Planning Margin until it is replaced by conversion of the Simple Cycle Gas Turbines to the Planning Margin role in 2019. Finally, the brown dotted line represents the sum of the Expected peak capacity requirements, plus Planning Margin.

Figure 8.2.3-B: Preferred Resource Strategy – Capacity Load / Resource Balance



8.3 Transmission Considerations

FortisBC's ability to locate new generation in the Kelowna area is a key determinant of impacts associated with transmission infrastructure. The key to successful amelioration of potential transmission impacts (environmental and economic) is to defer or eliminate the need to construct transmission infrastructure. As discussed in Section 3.9 above, FortisBC has assumed that additional transmission infrastructure will be required to support the Okanagan load center. The P3 - HYBRID portfolio assumes that the Simple Cycle Gas Turbines will be located in the North Okanagan, although the viability of such a location needs to be the subject of further study. As a result the P3 - HYBRID portfolio may defer or eliminate the need to construct the additional transmission infrastructure necessary to move new generation to the Kelowna load – estimated to cost in the range $70 million to $500 million+.

8.4 Environmental Considerations

The P3 - HYBRID portfolio requires the construction of Simple Cycle Gas Turbines which will produce some greenhouse gas emissions. However, the emissions are limited, and by 2019, in normal operations, would cease. Those emissions will be minimized by running the Simple Cycle Gas Turbines primarily as a peaking facility for the period 2014 to 2018 until the Pumped Storage Hydro facility takes over peaking operations. Peaking operations equate to less than 1% average effective capacity of the Simple Cycle Gas Turbines, with the peak year being 5.9% in 2016. From 2019 the Simple Cycle Gas Turbines are placed on standby in the Planning Margin role. Total greenhouse gas emissions will be approximately 115,000 tonnes over the planning period of this 2009 Resource Plan – which equates to approximately 25% of the greenhouse gas emissions that would be produced by continuing to rely upon the wholesale electricity market. Running the Simple Cycle Gas Turbines in excess of peaking requirements could occur if electricity market economics indicate that surplus sales would benefit FortisBC's ratepayers. Run time in excess of planned peaking operations would produce additional greenhouse gas emissions at the rate of approximately ½ tonne per MWh.

FortisBC's environmental performance will be improved by the P3 – HYBRID portfolio's green resources (the Pumped Storage Hydro facility, Small Hydro, and Clean energy facilities) when they come on line, and enhanced by the use of new and existing clean and renewable resources to provide the energy necessary to refill the Pumped Storage Hydro facility during Light Load Hours.

The storage and energy shaping capabilities provided by both the Small Hydro and Pumped Storage Hydro facilities would enable FortisBC to incorporate more intermittent clean resources to its system as required in the future. These attributes of the P3 – HYBRID portfolio's storage resources are necessary enablers for FortisBC's customers to pursue, on a larger scale, distributed generation sources such as backyard wind turbines, and rooftop solar systems. Further, these storage attributes could provide FortisBC with an opportunity to support clean and renewable resources outside the Company's service territory.

Therefore, when the entire portfolio is considered, the overall environmental benefits of the P3 – HYBRID portfolio are, in the Company's opinion, considered favourable.

8.5 BC Energy Plan

The P3 – HYBRID portfolio meets the objectives of all of the BC Energy Plan Policy Actions enumerated in Table 3.5.2.1 above, including Policy Action 20 (zero greenhouse gas emissions from coal), 18 (zero net greenhouse gas emissions) and 19 (zero net greenhouse gas emissions from existing thermal by 2016). 100% of dependable capacity is from clean energy sources[70]. This meets the Policy Action 21 goal of 90%. Further, the P3 – HYBRID portfolio contributes to provincial self-sufficiency goals (Policy Action 10).

8.6 Economics and Rate Implications

8.6.1 Capital Expenditures

The capital expenditures for the P3 – HYBRID portfolio are noted in Table 8.6.1-A below.

Table 8.6.1-A: Preferred Resource Strategy Capital Expenditure

Preferred Resource Strategy	Year in Service	Capital Cost (C$2009 million)
Simple Cycle Gas Turbine (SCGT)	2014	$88.0
Small Hydro with Capacity	2017	$148.0
Pumped Storage Hydro (PSH)	2019	$510.0
Wind	2021	$63.0
Total		**$809.0**

Willis Energy Services Ltd., which provided the capital expenditure estimates, was asked to comment on the confidence range it attached to its capital expenditure estimates for the P3 – HYBRID portfolio. It advised as follows in Table 8.6.1-B.

Table 8.6.1-B: Preferred Resource Strategy Capital Cost Confidence Range

PRS Capital Cost Confidence Range

Resource Option	Cost Estimate Range	Comments
Simple Cycle Gas Turbine	-10 % to +20 %	Well defined plant type
Small Hydro with Capacity	-20 % to +30 %	Site dependant
Pumped Storage Hydro Facility	-20 % to +50 %	Plant type not well defined and site dependant
Wind	-20 % to +30 %	Site dependant

[70] Inclusive of existing PPAs, and excluding the Planning Margin.

8.6.2 Costs (on a net present value basis) and Rate Impact

Table 8.6.2 below sets out the cost elements that make up the total (at 8% in $2009) cost (on a net present value basis) of the P3 – HYBRID portfolio. Table 8.6.2 also includes the average annual and total 20 year cumulative rate impacts of the P3 – HYBRID portfolio.

Table 8.6.2: Preferred Resource Strategy Net Present Value Cost Elements

	Portfolio Cost Elements (NPV @8% in $2009 millions)							
	A	B	C	D	E	F		
Portfolio	Cost for Market Purchases	Power Cost for New Resources	Surplus Energy Sales	Capital Related Cost	Planning Margin	**Total**	Average Annual Rate Impact	20 Year Cumulative Rate Impact
Preferred Resource Strategy	$7.8	$61.3	($31.8)	$272.7	$11.8	**$321.9**	1.18%	25.75%

Column A - cost of purchasing capacity and energy from the wholesale electricity market prior to new portfolio resources coming on-line.
Column B - represents the costs associated with power production, including variable O&M, fuel, and GHG-related costs. For the Preferred Resource Strategy this includes the refill costs associated with the PSH, as discussed in Section 7.3.1.
Column C - represents potential surplus sales revenues, based upon the forecast in Table 7.6.
Column D - represents all rate requirement capital-related costs associated with new capital investment.
Column E - represents the cost associated with the market-based interim Planning Margin product purchased prior to a portfolio having a physical Planning Margin in place.
Column F is the total of Columns A through E

The P3 – HYBRID portfolio will, (for the "expected" load, net present value of Revenue Requirements using an 8% (real) discount rate in 2009 dollars, over the planning period of this 2009 Resource Plan) cost approximately $322 million, including $12 million for the interim market-based Planning Margin, and approximately $32 million in surplus sales.

In order to manage and minimize both rate implications and reliability risk related to the Planning Margin, FortisBC has chosen to phase-in the acquisition of the market-based, interim Planning Margin pending the Simple Cycle Gas Turbines' conversion to the Planning Margin role in 2019.

FortisBC has investigated the potential economic benefit of running the Simple Cycle Gas Turbines to take advantage of market opportunities[71]. Even though there appear to be few predictable opportunities to engage in profitable off-system sales, the Company would be well positioned to take advantage of short term market excursions and this could generate economic benefits to offset the rate impact of the

[71] Please see Appendix I-2 for the Willis Energy Services Ltd. report on the subject.

P3 – HYBRID portfolio. Of course, this would also require the acquisition of the required environmental offsets.

The Pumped Storage Hydro facility provides FortisBC with similar opportunities to take advantage of short term market price excursions to generate economic benefits to offset the rate impact of the P3 – HYBRID portfolio. Additionally, the storage attributes of the Pumped Storage Hydro facility are considered to have economic potential in the sale of related ancillary services to shape and firm otherwise intermittent power from other renewable resources. The as-yet-unformed market for these services could include both British Columbia as it continues to develop renewable sources of electricity and the United States as it seeks capacity to support its Renewable Portfolio Standards.

The rate impact for the P3 – HYBRID portfolio, without consideration for potential revenue streams as discussed above, equates to an annual average of 1.18%. The twenty year cumulative rate impact is 25.75%.

8.7 Preferred Resource Strategy Data Summary

Table 8.7 below summarizes dependable capacity, planning margin and energy data for the P3 – HYBRID portfolio.

Table 8.7: Preferred Resource Strategy Summary

Dependable Capacity (MW)	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Forecast Peak Capacity Gap	144.5	150.6	157.6	164.8	170.5	174.8	179.4	184.0	188.7	193.4	198.1	202.8	207.5	212.2	216.8	221.4	225.9	230.4	234.9	239.2
SCGT	0.0	0.0	0.0	0.0	0.0	76.4	76.4	76.4	76.4	76.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Small Hydro	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	37.2	37.2	37.2	37.2	37.2	37.2	37.2	37.2	37.2	37.2	37.2	37.2
PSH	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0	200.0
Wind	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	7.5	7.5	7.5	7.5	7.5	7.5	7.5	7.5
Wholesale Market Purchase	144.5	150.6	157.6	164.8	170.5	98.4	103.0	107.6	75.1	79.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Excess Capacity	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	39.1	34.4	37.2	32.5	27.9	23.3	18.8	14.3	9.8	5.5
Planning Margin (MW)	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Required	44.6	45.1	45.7	46.3	46.8	47.3	47.8	48.2	48.7	49.1	49.6	50.0	50.5	50.9	51.3	51.7	52.2	52.6	53.0	53.3
SCGT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	76.4	76.4	76.4	76.4	76.4	76.4	76.4	76.4	76.4	76.4
Wholesale Market Purchase	0.0	5.0	10.2	15.4	20.8	26.3	31.8	37.5	43.3	49.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Energy (GWh)	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Forecast Gap	18.2	21.8	25.9	29.1	33.4	35.8	38.4	41.4	46.5	52.1	58.0	63.3	70.6	77.3	84.1	90.5	99.1	108.2	119.2	130.5
New Resources	0.0	0.0	0.0	0.0	0.0	34.2	36.5	39.2	163.7	165.3	211.8	217.2	290.2	296.8	303.7	310.1	318.6	327.7	338.7	350.0
Wholesale Market Purchase	18.2	21.8	25.9	29.1	33.4	1.6	1.9	2.2	0.3	0.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Surplus	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(128.9)	(124.5)	(109.0)	(105.1)	(156.6)	(152.7)	(148.8)	(144.9)	(141.9)	(138.2)	(133.9)	(129.1)

Average Annual Rate Impact = 1.18% **Cumulative Annual Rate Impact =** 25.78%

9 ACTION PLAN

To implement the P3 – HYBRID portfolio as its preferred resource strategy, FortisBC proposes the following Action Plan:

1. The Company will implement its preferred resource strategy, as outlined in Section 8 above, pursuant to the following:

   (a) FortisBC requests that the Commission accept this 2009 Resource Plan (including, without limitation, the Commission accept the P3 – HYBRID portfolio as the Company's preferred resource strategy), and determine that carrying out this 2009 Resource Plan would be in the public interest, all pursuant to Section 44.1(6)(a) of the Act; and

   (b) FortisBC requests that the Commission accept the following schedule of proposed expenditures, and determine that making the expenditures would be in the public interest, all pursuant to Section 44.2(3)(a) of the Act:

      (i) **Planning Margin:** expenditures of up to **$150,000 required in 2010**. These funds are for the preparation and implementation of an RFP process that will result in the identification of a preferred planning margin (capacity product) resource for which FortisBC will file with the Commission an application pursuant to Section 71 of the Act. The interim Planning Margin is required as a medium term, bridging resource until the acquisition of the Pumped Storage Hydro facility as noted below.

      (ii) **Simple Cycle Gas Turbine:** expenditures of up to **$1.5 million required in 2010 and 2011**. These funds are to complete pre-CPCN work necessary to prepare and file a CPCN application in time to meet an in-service date of 2014. This pre-CPCN work will include (a) site evaluations and acquisition, (b) environmental assessment, and (c) pre-engineering cost assessment work. The pre-engineering cost assessment work will develop the detailed cost assessments required to identify the funds necessary to develop a CPCN application for a Simple Cycle Gas Turbine plant. The pre-engineering cost assessments, an update on the status of the environmental assessment, as well as a request for CPCN development funds will be filed with the Commission by the end of 2010. A full CPCN application will be filed in 2011.

(iii) **Small Hydro:** expenditures of up to **$500,000 required in 2010**. These funds are to complete the pre-CPCN work necessary to prepare and file a CPCN application in time to meet an in-service date of 2017. This work will include (a) site evaluations and acquisition, and (b) pre-engineering cost assessment work. The pre-engineering cost assessment work will develop the detailed cost assessments required to identify the funds necessary to develop a CPCN application for a Small Hydro with Capacity facility. The pre-engineering cost assessments, as well as a request for CPCN development and environmental assessment funds will be filed with the Commission by the end of 2010. A full CPCN application will be filed in 2012.

(iv) **Pumped Storage Hydro:** expenditures of up to **$500,000 required in 2010**. These funds are to complete the pre-CPCN work necessary to prepare and file a CPCN application in time to meet a proposed in-service date of 2019. The pre-CPCN work will include (a) site evaluations, selection and acquisition work, and (b) pre-engineering cost assessments. The pre-engineering cost assessment work will develop the detailed cost assessments required to identify the funds necessary to develop a CPCN application for a Pumped Storage Hydro facility. The pre-engineering cost assessments, as well as a request for CPCN development and environmental assessment funds will be filed with the Commission by the end of 2010. A full CPCN application will be filed in 2012.

(v) **Clean:** expenditures of up to **$250,000 required in 2012**. These funds are for the investigation of the potential for a new Clean Energy resource(s) suitable for FortisBC are in the public interest. It is anticipated that this investigation may take the form of a Clean Call for Power, however, further study is required. A report on this investigation, as well as timetable for development necessary to bring this resource into service by 2021 will be filed with the Commission in 2014.

2. In accordance with Section 44.1(2) of the Act, the Company proposes to update this Resource Plan in two years (that is, by 2011), or sooner, if circumstances materially change prior to that time or at such other time as the Commission requires.

List of Appendices

A	Draft Order
B	BC Energy Plan
C	Environics Stakeholder Consultation
D-1	WECC 10-Year Coordinated Plan Summary (July 2006)
D-2	WECC 2008 Power Supply Assessment
E	Willis Energy Services - Market Analysis
F	Willis Energy Services - Load Forecast & Monte Carlo Key Inputs
G	FortisBC Strategic Demand Side Management Report
H-1	Willis Energy Services - Planning Reserve Margin
H-2	Manitoba Hydro HVDC Research Centre - 20 Year Resource Adequacy Study
I-1	Willis Energy Services - Resource Options Report
I-2	Willis Energy Services - Economic Running of Simple Cycle Gas Turbine
I-3	FortisBC Transmission Required for New Resources

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BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-XX-09

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by FortisBC Inc.
for
2009 Resource Plan

BEFORE: XXXXXX, Panel Chair and Commissioner
XXXXXX, Commissioner
XX, 2009

O R D E R

WHEREAS:

A. On May 29, 2009 FortisBC Inc. ("FortisBC") filed an application (the "Application") with the British Columbia Utilities Commission (the "Commission") pursuant to sections 44.1, 44.2, and 64.01(2) of the Utilities Commission Act (the "Act") for approval of its Resource Plan (the "2009 Resource Plan") relating to the period from 2009 to 2028; and

B. In the Application FortisBC requests an order, pursuant to section 44.1(6)(a) of the Act, that the Commission accept the 2009 Resource Plan (including, without limitation, the P3 – HYBRID portfolio described in Section 8 of the 2009 Resource Plan as the Company's preferred resource strategy), and determine that carrying out the 2009 Resource Plan would be in the public interest;

C. In the Application the Company also requests an order, pursuant to section 44.2(3)(a) of the Act, that the Commission accept the schedule of proposed expenditures described in Section 9 of the 2009 Resource Plan, and determine that making the expenditures would be in the public interest; and

D. The Commission has reviewed the Application and submissions of FortisBC and intervenors and finds that approval of the Application is warranted and in the public interest.

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-XX-09

NOW THEREFORE the Commission orders as follows:

1. The Commission accepts the 2009 Resource Plan, (including, without limitation, the P3 – HYBRID portfolio described in Section 8 of the 2009 Resource Plan as the Company's preferred resource strategy), and determines that carrying out the 2009 Resource Plan would be in the public interest, all pursuant to section 44.1(6)(a) of the Act.

2. The Commission accepts the following schedule of proposed expenditures, and determines that making the expenditures would be in the public interest, all pursuant to section 44.2(3)(a) of the Act:

    (a) expenditures of approximately $0.15 million to conduct a Request for Proposals process for a medium term power purchase agreement;
    (b) expenditures of approximately $1.5 million to determine the feasibility of FortisBC's proposed Simple Cycle Gas Turbine;
    (c) expenditures of approximately $0.5 million to determine the feasibility of FortisBC's proposed Small Hydro generating plant;
    (d) expenditures of approximately $0.5 million to determine the feasibility of FortisBC's proposed Pumped Storage Hydro generating plant; and
    (e) expenditures of approximately $0.25 million for the investigation of the potential for a new clean energy resource.

DATED at the City of Vancouver, in the Province of British Columbia, this day of 20xx.

BY ORDER

Original signed by:

XXXXXXX
Panel Chair and Commissioner

The BC Energy Plan

A Vision for Clean Energy Leadership

BRITISH COLUMBIA
The Best Place on Earth

FortisBC 2009 Resource Plan
Appendix B

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MESSAGE FROM THE PREMIER

The BC Energy Plan: A Vision for Clean Energy Leadership is British Columbia's plan to make our province energy self-sufficient while taking responsibility for our natural environment and climate. The world has turned its attention to the critical issue of global warming. This plan sets ambitious targets. We will pursue them relentlessly as we build a brighter future for B.C.

The BC Energy Plan sets out a strategy for reducing our greenhouse gas emissions and commits to unprecedented investments in alternative technology based on the work that was undertaken by the Alternative Energy Task Force. Most importantly, this plan outlines the steps that all of us – including industry, environmental agencies, communities and citizens – must take to reach these goals for conservation, energy efficiency and clean energy so we can arrest the growth of greenhouse gases and reduce human impacts on the climate.

As stewards of this province, we have a responsibility to manage our natural resources in a way that ensures they both meet our needs today and the needs of our children and grandchildren. We will all have to think and act differently as we develop innovative and sustainable solutions to secure a clean and reliable energy supply for all British Columbians.

Our plan will make B.C. energy self-sufficient by 2016. To do this, we must maximize our conservation efforts. Conservation will reduce pressure on our energy supply and result in real savings for those who use less energy. Individual actions that reduce our own everyday energy consumption will make the difference between success and failure. For industry, conservation can lead to an effective, productive and significant competitive advantage. For communities, it can lead to healthier neighbourhoods and lifestyles for all of us.

We are looking at how we can use clean alternative energy sources, including bioenergy, geothermal, fuel cells, water-powered electricity, solar and wind to meet our province's energy needs. With each of these new options comes the opportunity for new job creation in areas such as research, development, and production of innovative energy and conservation solutions. The combination of renewable alternative energy sources and conservation will allow us to pursue our potential to become a net exporter of clean, renewable energy to our Pacific neighbours.

Just as the government's energy vision of 40 years ago led to massive benefits for our province, so will our decisions today. **The BC Energy Plan** will ensure a secure, reliable, and affordable energy supply for all British Columbians for years to come.

Premier Gordon Campbell

MESSAGE FROM THE MINISTER

The BC Energy Plan: A Vision for Clean Energy Leadership is a made-in-B.C. solution to the common global challenge of ensuring a secure, reliable supply of affordable energy in an environmentally responsible way. In the next decade government will balance the opportunities and increased prosperity available from our natural resources while leading the world in sustainable environmental management.

This energy plan puts us in a leadership role that will see the province move to eliminating or offsetting greenhouse gas emissions for all new projects in the growing electricity sector, end flaring from oil and gas producing wells, and put in place a plan to make B.C. electricity self-sufficient by 2016.

In developing this plan, the government met with key stakeholders, environmental non-government organizations, First Nations, industry representatives and others. In all, more than 100 meetings were held with a wide range of parties to gather ideas and feedback on new policy actions and strategies now contained in **The BC Energy Plan**.

By building on the strong successes of Energy Plan 2002, this energy plan will provide secure, affordable energy for British Columbia. Today, we reaffirm our commitment to public ownership of our BC Hydro assets while broadening our supply of available energy.

We look towards British Columbia's leading edge industries to help develop new, greener generation technologies with the support of the new **Innovative Clean Energy Fund**. We're planning for tomorrow, today. Our energy industry creates jobs for British Columbians, supports important services for our families, and will play an important role in the decade of economic growth and environmental sustainability that lies ahead.

The Ministry of Energy, Mines and Petroleum Resources is responding to challenges and opportunities by delivering innovative, sustainable ways to develop British Columbia's energy resources.

Honourable Richard Neufeld
Minister of Energy, Mines and Petroleum Resources

THE BC ENERGY PLAN HIGHLIGHTS

In 2002, the Government of British Columbia launched an ambitious plan to invigorate the province's energy sector. Energy for Our Future: A Plan for BC was built around four cornerstones: low electricity rates and public ownership of BC Hydro; secure, reliable supply; more private sector opportunities; and environmental responsibility with no nuclear power sources. Today, our challenges include a growing energy demand, higher prices, climate change and the need for environmental sustainability. **The BC Energy Plan: A Vision for Clean Energy Leadership** builds on the successes of the government's 2002 plan and moves forward with new policies to meet the challenges and opportunities ahead.

British Columbia's current electricity supply resources are 90 per cent clean and new electricity generation plants will have zero net greenhouse gas emissions.

Environmental Leadership

The BC Energy Plan puts British Columbia at the forefront of environmental and economic leadership by focusing on our key natural strengths and our competitive advantages of clean and renewable sources of energy. The plan further strengthens our environmental leadership through the following key policy actions:

- Zero greenhouse gas emissions from coal fired electricity generation.
- All new electricity generation projects will have zero net greenhouse gas emissions.
- Zero net greenhouse gas emissions from existing thermal generation power plants by 2016.
- Ensure clean or renewable electricity generation continues to account for at least 90 per cent of total generation.
- No nuclear power.
- Best coalbed gas practices in North America.
- Eliminate all routine flaring at oil and gas producing wells and production facilities by 2016 with an interim goal to reduce flaring by half (50 per cent) by 2011.

A Strong Commitment to Energy Conservation and Efficiency

Conservation is integral to meeting British Columbia's future energy needs. **The BC Energy Plan** sets ambitious conservation targets to reduce the growth in electricity used within the province. British Columbia will:

- Set an ambitious target, to acquire 50 per cent of BC Hydro's incremental resource needs through conservation by 2020.
- Implement energy efficient building standards by 2010.

Current per household electricity consumption for BC Hydro customers is about 10,000 Kwh per year. Achieving this conservation target will see electricity use per household decline to approximately 9,000 Kwh per year by 2020.

Energy Security

The Government of British Columbia is taking action to ensure that the energy needs of British Columbians continue to be met now and into the future. As part of ensuring our energy security, **The BC Energy Plan** sets the following key policy actions:

- Maintain public ownership of BC Hydro and the BC Transmission Corporation.
- Maintain our competitive electricity rate advantage.
- Achieve electricity self-sufficiency by 2016.
- Make small power part of the solution through a set purchase price for electricity generated from projects up to 10 megawatts.
- Explore value-added opportunities in the oil and gas industry by examining the viability of a new petroleum refinery and petrochemical industry.
- Be among the most competitive oil and gas jurisdictions in North America.
- BC Hydro and the Province will enter into initial discussions with First Nations, the Province of Alberta and communities to discuss Site C to ensure that communications regarding the potential project and the processes being followed are well known.

Investing in Innovation

British Columbia has a proven track record in bringing ideas and innovation to the energy sector. From our leadership and experience in harnessing our hydro resources to produce electricity, to our groundbreaking work in hydrogen and fuel cell technology, British Columbia has always met its future energy challenges by developing new, improved and sustainable solutions. To support future innovation and to help bridge the gap experienced in bringing innovations through the pre-commercial stage to market, government will:

- Establish an Innovative Clean Energy Fund of $25 million.
- Implement the BC Bioenergy Strategy to take full advantage of B.C.'s abundant sources of renewable energy.
- Generate electricity from mountain pine beetle wood by turning wood waste into energy.

Ambitious Energy Conservation and Efficiency Targets

The more energy that is conserved, the fewer new sources of supply we will require in the future. That is why British Columbia is setting new conservation targets to reduce growth in electricity demand.

Inefficient use of energy leads to higher costs and many environmental and security of supply problems.

Conservation Target

The BC Energy Plan sets an ambitious conservation target, to acquire 50 per cent of BC Hydro's incremental resource needs through conservation by 2020. This will require building on the "culture of conservation" that British Columbians have embraced in recent years.

The plan confirms action on the part of government to complement these conservation targets by working closely with BC Hydro and other utilities to research, develop, and implement best practices in conservation and energy efficiency and to increase public awareness. In addition, the plan supports utilities in British Columbia and the BC Utilities Commission pursuing all cost effective and competitive demand side management programs. Utilities are also encouraged to explore and develop rate designs to encourage efficiency, conservation and the development of renewable energy.

Future energy efficiency and conservation initiatives will include:

- Continuing to remove barriers that prevent customers from reducing their consumption.
- Building upon efforts to educate customers about the choices they can make today with respect to the amount of electricity they consume.
- Exploring new rate structures to identify opportunities to use rates as a mechanism to motivate customers either to use less electricity or use less at specific times.
- Employing new rate structures to help customers implement new energy efficient products and technologies and provide them with useful information about their electricity consumption to allow them to make informed choices.
- Advancing ongoing efforts to develop energy-efficient products and practices through regulations, codes and standards.

POLICY ACTIONS

COMMITMENT TO CONSERVATION

- **Set an ambitious conservation target, to acquire 50 per cent of BC Hydro's incremental resource needs through conservation by 2020.**
- **Ensure a coordinated approach to conservation and efficiency is actively pursued in British Columbia.**
- **Encourage utilities to pursue cost effective and competitive demand side management opportunities.**
- **Explore with B.C. utilities new rate structures that encourage energy efficiency and conservation.**

The average household uses about 10,000 kilowatt-hours of electricity per year.

Implement Energy Efficiency Standards for Buildings by 2010

British Columbia implemented *Energy Efficient Buildings: A Plan for BC* in 2005 to address specific barriers to energy efficiency in our building stock through a number of voluntary policy and market measures. This plan has seen a variety of successes including smart metering pilot projects, energy performance measurement and labelling, and increased use of Energy Star appliances. In 2005, B.C. received a two year, $11 million federal contribution from the Climate Change Opportunities Envelope to support implementation of this plan.

Working together industry, local governments, other stakeholders and the provincial government will determine and implement cost effective energy efficiency standards for new buildings by 2010. Regulated standards for buildings are a central component of energy efficiency programs in leading jurisdictions throughout the world.

The BC Energy Plan supports reducing consumption by raising awareness and enhancing the efforts of utilities, local governments and building industry partners in British Columbia toward conservation and energy efficiency.

Aggressive Public Sector Building Plan

The design and retrofit of buildings and their surrounding landscapes offer us an important means to achieve our goal of making the government of British Columbia carbon neutral by 2010, and promoting Pacific Green universities, colleges, hospitals, schools, prisons, ferries, ports and airports.

British Columbia communities are already recognized leaders in innovative design practices. We know how to build smarter, faster and smaller. We know how to increase densities, reduce building costs and create new positive benefits for our environment. We know how to improve air quality, reduce energy consumption and make wise use of other resources, and how to make our landscapes and buildings healthy places for living, working and learning. We know how to make it affordable.

Government will set the following ambitious goals for all publicly funded buildings and landscapes and ask the Climate Action Team to determine the most credible, aggressive and economically viable options for achieving them:

- Require integrated environmental design to achieve the highest standards for greenhouse gas emission reductions, water conservation and other building performance results such as a certified standard.
- Supply green, healthy workspaces for all public service employees.
- Capture the productivity benefits for people who live and work in publicly funded buildings such as reduced illnesses, less absenteeism, and a better learning environment.
- Aim not only for the lowest impact, but also for restoration of the ecological features of the surrounding landscapes.

Gigawatt = 1,000,000 kilowatts
Kilowatt = amount of power to light ten 100-watt incandescent light bulbs.

ENERGY CONSERVATION AND EFFICIENCY

Community Action on Energy Efficiency

British Columbia is working in partnership with local governments to encourage energy conservation at the community level through the Community Action on Energy Efficiency Program. The program promotes energy efficiency and community energy planning projects, providing direct policy and technical support to local governments through a partnership with the Fraser Basin Council. A total of 29 communities are participating in the program and this plan calls for an increase in the level of participation and expansion of the program to include transportation actions. The Community Action on Energy Efficiency Program is a collaboration among the provincial ministries of Energy, Mines and Petroleum Resources, Environment, and Community Services, Natural Resources Canada, the Fraser Basin Council, Community Energy Association, BC Hydro, FortisBC, Terasen Gas, and the Union of BC Municipalities.

Leading the Way to a Future with Green Buildings and Green Cities

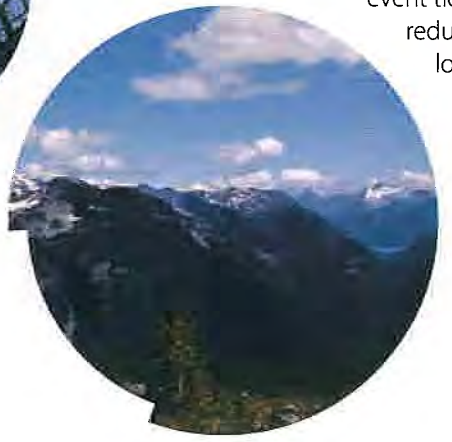
British Columbia has taken a leadership role in the development of green buildings. Through the Green Buildings BC Program, the province is working to reduce the environmental impact of government buildings by increasing energy and water efficiency and reducing greenhouse gas emissions. Through this program, and the Energy Efficient Buildings Strategy that establishes energy efficiency targets for all types of buildings, the province is inviting businesses, local governments and all British Columbians to do their part to increase energy efficiency and reduce greenhouse gas emissions.

The Green Cities Project sets a number of strategies to make our communities greener, healthier and more vibrant places to live. British Columbia communities are already recognized leaders in innovative sustainability practices, and the Green Cities Project will provide them with additional resources to improve air quality, reduce energy consumption and encourage British Columbians to get out and enjoy the outdoors. With the Green Cities Project, the provincial government will:

- Provide $10 million a year over four years for the new LocalMotion Fund, which will cost share capital projects on a 50/50 basis with municipal governments to build bike paths, walkways, greenways and improve accessibility for people with disabilities.
- Establish a new Green City Awards program to encourage the development and exchange of best practices by communities, with the awards presented annually at the Union of British Columbia Municipalities convention.
- Set new financial incentives to help local governments shift to hybrid vehicle fleets and help retrofit diesel vehicles.
- Commit to making new investments in expanded rapid transit, support for fuel cell vehicles and other innovations.

Industrial Energy Efficiency Program

Government will establish an Industrial Energy Efficiency Program for British Columbia to address challenges and issues faced by the B.C. industrial sector and support the Canada wide industrial energy efficiency initiatives. The program will encourage industry driven investments in energy efficient technologies and processes; reduce emissions and greenhouse gases; promote self generation of power; and reduce funding barriers that discourage energy efficiency in the industrial sector. Some specific strategies include developing a results based pilot program with industry to improve energy efficiency and reduce overall power consumption and promote the generation of renewable energy within the industrial sector.



The 2010 Olympic and Paralympics Games: Sustainability in Action

In 2010 Vancouver and Whistler will host the Winter Olympic and Paralympic Games. The 2010 Olympic Games are the first that have been organized based on the principles of sustainability.

All new buildings for the Olympics will be designed and built to conserve both water and materials, minimize waste, maximize air quality, protect surrounding areas and continue to provide environmental and community benefits over their lifetimes. Existing venues will be upgraded to showcase energy conservation and efficiency and demonstrate the use of alternative heating/cooling technologies. Wherever possible, renewable energy sources such as wind, solar, micro hydro, and geothermal energy will be used to power and heat all Games facilities.

Transportation for the 2010 Games will be based on public transit. This system – which will tie event tickets to transit use – will help reduce traffic congestion, minimize local air pollution and limit greenhouse gas emissions.

POLICY ACTIONS

BUILDING STANDARDS, COMMUNITY ACTION AND INDUSTRIAL EFFICIENCY

- Implement Energy Efficiency Standards for Buildings by 2010.
- Undertake a pilot project for energy performance labelling of homes and buildings in coordination with local and federal governments, First Nations and industry associations.
- New provincial public sector buildings will be required to integrate environmental design to achieve the highest standards for greenhouse gas emission reductions, water conservation and other building performance results such as a certified standard.
- Develop an Industrial Energy Efficiency Program for British Columbia to address specific challenges faced by British Columbia's industrial sector.
- Increase the participation of local governments in the Community Action on Energy Efficiency Program and expand the First Nations and Remote Community Clean Energy Program.

ELECTRICITY

British Columbia benefits from the public ownership of BC Hydro and the BC Transmission Corporation.

POLICY ACTIONS

SELF-SUFFICIENCY BY 2016

- Ensure self-sufficiency to meet electricity needs, including "insurance."
- Establish a standing offer for clean electricity projects up to 10 megawatts.
- The BC Transmission Corporation is to ensure that British Columbia's transmission technology and infrastructure remains at the leading edge and has the capacity to deliver power efficiently and reliably to meet growing demand.
- Ensure adequate transmission system capacity by developing and implementing a transmission congestion relief policy.
- Ensure that the province remains consistent with North American transmission reliability standards.

Electricity Security

Electricity, while often taken for granted, is the lifeblood of our modern economy and key to our entire way of life. Fortunately, British Columbia has been blessed with an abundant supply of clean, affordable and renewable electricity. But today, as British Columbia's population has grown, so too has our demand for electricity. We are now dependent on other jurisdictions for up to 10 per cent of our electricity supply. BC Hydro estimates demand for electricity to grow by up to 45 per cent over the next 20 years.

We must address this ever increasing demand to maintain our secure supply of electricity and the competitive advantage in electricity rates that all British Columbians have enjoyed for the last 20 years. There are no simple solutions or answers. We have an obligation to future generations to chart a course that will ensure a secure, environmentally and socially responsible electricity supply.

To close this electricity gap, and for our province to become electricity self-sufficient, will require an innovative electricity industry and the real commitment of all British Columbians to conservation and energy efficiency.

The New Relationship and Electricity

The Government of British Columbia is working with First Nations to restore, revitalize and strengthen First Nations communities. The goal is to build strong and healthy relationships with First Nations people guided by the principles of trust and collaboration. First Nations share many of the concerns of other British Columbians in how the development of energy resources may impact as well as benefit their communities. In addition, First Nations have concerns with regard to the recognition and respect of Aboriginal rights and title.

By focusing on building partnerships between First Nations, industry and government, tangible social and economic benefits will flow to First Nations communities across the province and assist in eliminating the gap between First Nations people and other British Columbians.

Government is working every day to ensure that energy resource management includes First Nations' interests, knowledge and values. By continuing to engage First Nations in energy related issues, we have the opportunity to share information and look for opportunities to facilitate First Nations' employment and participation in the electricity sectors to ensure that First Nations people benefit from the continued growth and development of British Columbia's resources. **The BC Energy Plan** provides British Columbia with a blueprint for facing the many energy challenges and opportunities that lay ahead. It provides an opportunity to build on First Nations success stories such as:

- First Nations involvement in independent power projects, such as the Squamish First Nation's participation in the Furry Creek and Ashlu hydro projects.

- Almost $4 million will flow to approximately 10 First Nations communities across British Columbia to support the implementation of Community Energy Action Plans as part of the First Nation and Remote Community Clean Energy Program.
- The China Creek independent power project was developed by the Hupacasath First Nation on Vancouver Island.

Achieve Electricity Self-Sufficiency by 2016

Achieving electricity self-sufficiency is fundamental to our future energy security and will allow our province to achieve a reliable, clean and affordable supply of electricity. It also represents a lasting legacy for future generations of British Columbians. That's why government has committed that British Columbia will be electricity self-sufficient within the decade ahead.

Through **The BC Energy Plan**, government will set policies to guide BC Hydro in producing and acquiring enough electricity in advance of future need. However, electricity generation and transmission infrastructure require long lead times. This means that over the next two decades, BC Hydro must acquire an additional supply of "insurance power" beyond the projected increases in demand to minimize the risk and implications of having to rely on electricity imports.

Small Power Standing Offer

Achieving electricity self-sufficiency in British Columbia will require a range of new power sources to be brought on line. To help make this happen, this policy will direct BC Hydro to establish a Standing Offer Program with no quota to encourage small and clean electricity producers. Under the Standing Offer Program, BC Hydro will purchase directly from suppliers at a set price.

Eligible projects must be less than 10 megawatts in size and be clean electricity or high efficiency electricity cogeneration. The price offered in the standing offer contract would be based on the prices paid in the most recent BC Hydro energy call. This will provide small electricity suppliers with more certainty, bring small power projects into the system more quickly, and help achieve government's goal of maintaining a secure electricity supply. As well, BC Hydro will offer the same price to those in BC Hydro's Net Metering Program who have a surplus of generation at the end of the year.

Ensuring a Reliable Transmission Network

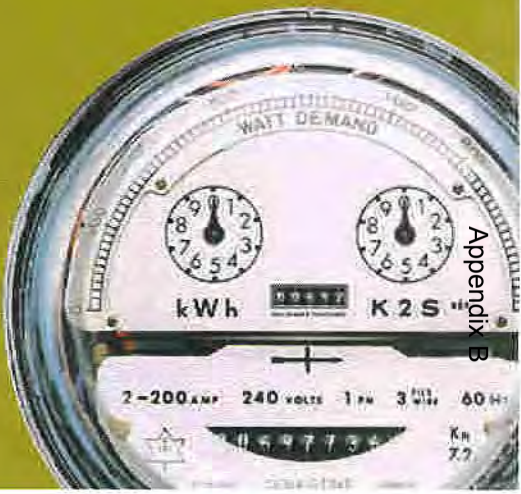
An important part of meeting the goal of self-sufficiency is ensuring a reliable transmission infrastructure is in place as additional power is brought on line. Transmission is a critical part of the solution as often new clean sources of electricity are located away from where the demand is. In addition, transmission investment is required to support economic growth in the province and must be planned and started in anticipation of future electricity needs given the long lead times required for transmission development. New and upgraded transmission infrastructure will be required to avoid congestion and to efficiently move the electricity across the entire power grid. Because our transmission system is part of a much larger, interconnected grid, we need to work with other jurisdictions to maximize the benefit of interconnection, remain consistent with evolving North American reliability standards, and ensure British Columbia's infrastructure remains capable of meeting customer needs.

BC HYDRO'S NET METERING PROGRAM: PEOPLE PRODUCING POWER

BC Hydro's Net Metering Program was established as a result of Energy Plan 2002. It is designed for customers with small generating facilities, who may sometimes generate more electricity than they require for their own use. A net metering customer's electricity meter will run backwards when they produce more electricity than they consume and run forward when they produce less than they consume.

The customer is only billed for their "net consumption", the total amount of electricity used minus the total produced.

Net metering allows customers to lower their environmental impact and take responsibility for their own power production. It helps to move the province towards electricity self-sufficiency and expands clean electricity generation, making B.C.'s electricity supply more environmentally sustainable.



ELECTRICITY

In order for British Columbia to ensure the development of a secure and reliable supply of electricity, **The BC Energy Plan** provides policy direction to the BC Transmission Corporation to ensure that our transmission technology and infrastructure remains at the leading edge and has the capacity to deliver power efficiently and reliably to meet growing demand. This will include ensuring there is adequate transmission capacity, ongoing investments in technology and infrastructure and remaining consistent with evolving North American reliability standards.

BC Transmission Corporation Innovation and Technology

As the manager of a complex and high-value transmission grid, BC Transmission Corporation is introducing technology innovations that provide improvements to the performance of the system and allow for a greater utilization of existing assets, ensuring B.C. continues to benefit from one of the most advanced energy networks in the world. BC Transmission Corporation's innovation program focuses on increasing the power transfer capability of existing assets, extending the life of assets and improving system reliability and security. Initiatives include:

- System Control Centre Modernization Project: This project is consolidating system operations into a new control center and backup site and upgrading operating technologies with a modern management system that includes enhancements to existing applications to ensure the electric grid is operating reliably and efficiently. The backup site will take over complete operation of the electric grid if the main site is unavailable.
- Real-Time Phasors: British Columbia is among the first North American jurisdictions to incorporate phasor measurement into control centre operations. Phasors are highly accurate voltage, current and phase angle "snapshots" of the real-time state of the transmission system that enable system operators to monitor system conditions and identify any impending problems.
- Real-Time Rating: This is a temperature monitoring system which enables the operation of two 500 kilovolt submarine cable circuits at maximum capacity without overloading. The resulting increase in capacity is estimated to be up to 10 per cent, saving millions of dollars.
- Electronic Temperature Monitor Upgrades for Station Transformers: In this program, existing mechanical temperature monitors will be replaced with newer, more accurate electronic monitors on station transformers that allow transformers to operate to maximum capacity without overheating. In addition to improving performance, BC Transmission Corporation will realize reduced maintenance costs as the monitors are "self-checking."
- Life Extension of Transmission Towers: BC Transmission Corporation maintains over 22,000 steel lattice towers and is applying a special composite corrosion protection coating to some existing steel towers to extend their life by about 25 years.

Public Ownership

Public Ownership of BC Hydro and the BC Transmission Corporation

BC Hydro and the BC Transmission Corporation are publicly-owned crown corporations and will remain that way now and into the future. BC Hydro is responsible for generating, purchasing and distributing electricity. The BC Transmission Corporation operates, maintains, and plans BC Hydro's transmission assets and is responsible for providing fair, open access to the power grid for all customers. Both crowns are subject to the review and approvals of the independent regulator, the BC Utilities Commission.

BC Hydro owns the heritage assets, which include historic electricity facilities such as those on the Peace and Columbia Rivers that provide a secure, reliable supply of low-cost power for British Columbians. These heritage assets require maintenance and upgrades over time to ensure they continue to operate reliably and efficiently. Potential improvements to these assets, such as capacity additions at the Mica and Revelstoke generating stations, can make important contributions for the benefit of British Columbians.

Confirming the Heritage Contract in Perpetuity

Under the 2002 Energy Plan, a legislated heritage contract was established for an initial term of 10 years to ensure BC Hydro customers benefit from its existing low-cost resources. With **The BC Energy Plan**, government confirms the heritage contract in perpetuity to ensure ratepayers will continue to receive the benefits of this low-cost electricity for generations to come.

British Columbia's Leadership in Clean Energy

The BC Energy Plan will continue to ensure British Columbia has an environmentally and socially responsible electricity supply with a focus on conservation and energy efficiency.

British Columbia is already a world leader in the use of clean and renewable electricity, due in part to the foresight of previous generations who built our province's hydroelectric dams. These dams - now British Columbians' 'heritage assets' - today help us to enjoy 90 per cent clean electricity, one of the highest levels in North America.

All New Electricity Generation Projects Will Have Zero Net Greenhouse Gas Emissions

The B.C. government is a leader in North America when it comes to environmental standards. While British Columbia is a province rich in energy resources such as hydro electricity, natural gas and coal, the use of these resources needs to be balanced through effective use, preserving our environmental standards, while upholding our quality of life for generations to come. The government has made a commitment that all new electricity generation projects developed in British Columbia and connected to the grid will have zero net greenhouse gas emissions. In addition, any new electricity generated from coal must meet the more stringent standard of zero greenhouse gas emissions.

POLICY ACTIONS

PUBLIC OWNERSHIP

- **Continue public ownership of BC Hydro and its heritage assets, and the BC Transmission Corporation.**
- **Establish the existing heritage contract in perpetuity.**
- **Invest in upgrading and maintaining the heritage asset power plants and the transmission lines to retain the ongoing competitive advantage these assets provide to the province.**

ELECTRICITY

POLICY ACTIONS

REDUCING GREENHOUSE GAS EMISSIONS FROM ELECTRICITY

- All new electricity generation projects will have zero net greenhouse gas emissions.
- Zero net greenhouse gas emissions from existing thermal generation power plants by 2016.
- Require zero greenhouse gas emissions from any coal thermal electricity facilities.
- Ensure clean or renewable electricity generation continues to account for at least 90 per cent of total generation.
- Government supports BC Hydro's proposal to replace the firm energy supply from the Burrard Thermal plant with other resources. BC Hydro may choose to retain Burrard for capacity purposes after 2014.
- No nuclear power.

Zero Net Greenhouse Gas Emissions from Existing Thermal Generation Power Plants by 2016

Setting a requirement for zero net emissions over this time period encourages power producers to invest in new or upgraded technology. For existing plants the government will set policy around reaching zero net emissions through carbon offsets from other activities in British Columbia. It clearly signals the government's intention to continue to have one of the lowest greenhouse gas emission electricity sectors in the world.

Ensure Clean or Renewable Electricity Generation Continues to Account For at Least 90 per cent of Total Generation

Currently in B.C., 90 per cent of electricity is from clean or renewable resources. **The BC Energy Plan** commits to maintaining this high standard which places us among the top jurisdictions in the world. Clean or renewable resources include sources of energy that are constantly renewed by natural processes, such as water power, solar energy, wind energy, tidal energy, geothermal energy, wood residue energy, and energy from organic municipal waste.

Zero Greenhouse Gas Emissions from Coal

The government is committed to ensuring that British Columbia's electricity sector remains one of the cleanest in the world and will allow coal as a resource for electricity generation when it can reach zero greenhouse gas emissions. Clean-coal technology with carbon sequestration is expected to become commercially available in the next decade. Therefore, the province will require zero greenhouse gas emissions from any coal thermal electricity facilities which can be met through capture and sequestration technology. British Columbia is the first Canadian jurisdiction to commit to using only clean coal technology for any electricity generated from coal.

Burrard Thermal Generating Station

A decision regarding the Burrard Thermal Natural Gas Generating Station is another action that is related to environmentally responsible electricity generation in British Columbia.

Even though it could generate electricity from Burrard Thermal, BC Hydro imports power primarily because the plant is outdated, inefficient and costly to run. However, Burrard Thermal still provides significant benefits to BC Hydro as it acts as a "battery" close to the Lower Mainland, and provides extra capacity or "reliability insurance" for the province's electricity supply. It also provides transmission system benefits that would otherwise have to be supplied through the addition of new equipment at Lower Mainland sub-stations.

By 2014, BC Hydro plans to have firm electricity to replace what would have been produced at the plant. Government supports BC Hydro's proposal to replace the firm energy supply from Burrard Thermal with other resources by 2014. However, BC Hydro may choose to retain the plant for "reliability insurance" should the need arise.

No Nuclear Power

As first outlined in Energy Plan 2002, government will not allow production of nuclear power in British Columbia.

Benefits to British Columbians

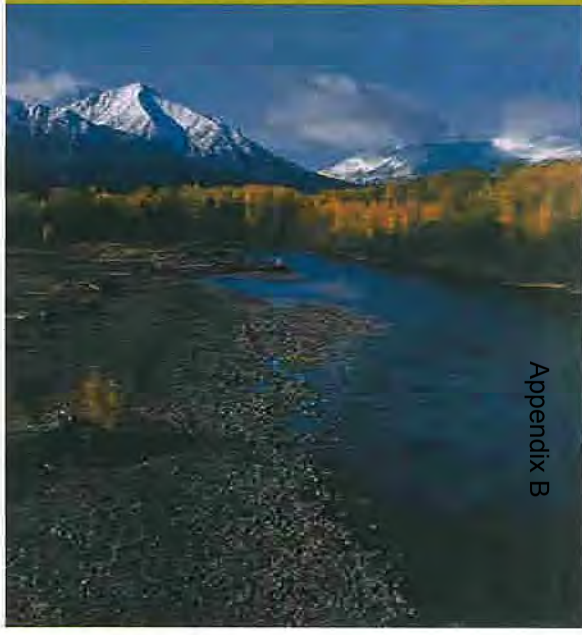
Clean or renewable electricity comes from sources that replenish over a reasonable time or have minimal environmental impacts. Today, demand for economically viable, clean, renewable and alternative energy is growing along with the world's population and economies. Consumers are looking for power that is not only affordable but creates minimal environmental impacts. Fortunately, British Columbia has abundant hydroelectric resources, and plenty of other potential energy sources.

Maintain our Electricity Competitive Advantage

British Columbians require a secure, reliable supply of competitively priced electricity now and in the future. Competitively priced power is also an incentive for investors to locate in British Columbia. It provides an advantage over other jurisdictions and helps sustain economic growth. We are fortunate that historic investments in hydroelectric assets provide electricity that is readily available, reliable, clean and inexpensive. By ensuring public ownership of BC Hydro, the heritage assets and the BC Transmission Corporation and confirming the heritage contract in perpetuity, we will ensure that ratepayers continue to receive the benefits of this low cost generation. Due to load growth and aging infrastructure, new investments will be required. Investments in maintenance and in some cases expansions can be a cost effective way to meet growth and reduce future rate increases.

CARBON OFFSETS AND HOW THEY REDUCE EMISSIONS

A carbon offset is an action taken directly, outside of normal operations, which results in reduced greenhouse gas emissions or removal of greenhouse gases from the atmosphere. Here's how it works: if a project adds greenhouse gases to the atmosphere, it can effectively subtract them by purchasing carbon offsets which are reductions from another activity. Government regulations to reduce greenhouse gases, including offsets, demonstrate leadership on climate change and support a move to clean and renewable energy.



ELECTRICITY

25

Government will establish a $25 million Innovative Clean Energy Fund.

POLICY ACTIONS

BENEFITS TO BRITISH COLUMBIANS

- Review BC Utilities Commissions' role in considering social and environmental costs and benefits.
- Ensure the procurement of electricity appropriately recognizes the value of aggregated intermittent resources.
- Work with BC Hydro and parties involved to continue to improve the procurement process for electricity.
- Pursue Government and BC Hydro's planned Remote Community Electrification Program to expand or take over electricity service to remote communities in British Columbia.
- Ensure BC Hydro considers alternative electricity sources and energy efficiency measures in its energy planning for remote communities.

British Columbia must look for new, innovative ways to stay competitive. New technologies must be identified and nurtured, from both new and existing industries. By diversifying and strengthening our energy sector through the development of new and alternative energy sources, we can help ensure the province's economy remains vibrant for years to come.

Ensure Electricity is Secured at Competitive Prices

One practical way to keep rates down is to ensure utilities have effective processes for securing competitively priced power. As part of **The BC Energy Plan**, government will work with BC Hydro and parties involved to continue to improve the Call for Tender process for acquiring new generation. Fair treatment of both buyers and sellers of electricity will facilitate a robust and competitive procurement process. Government and BC Hydro will also look for ways to further recognize the value of intermittent resources, such as run-of- river and wind, in the acquisition process – which means that BC Hydro will examine ways to value separate projects together to increase the amount of firm energy calculated from the resources.

Rates Kept Low Through Powerex Trading of Electricity

Profits from electricity trade also contribute to keeping our electricity rates competitive. BC Hydro, through its subsidiary, Powerex, buys and sells electricity when it is advantageous to British Columbia's ratepayers. Government will continue to support capitalizing on electricity trading opportunities and will continue to allocate trade revenue to BC Hydro ratepayers to keep electricity rates low for all British Columbians.

BC Utilities Commissions' Role in Social and Environmental Costs and Benefits

The BC Energy Plan clarifies that social, economic and environmental costs are important for ensuring a suitable electricity supply in British Columbia. Government will review the BC Utilities Commissions' role in considering social, environmental and economic costs and benefits, and will determine how best to ensure these are appropriately considered within the regulatory framework.

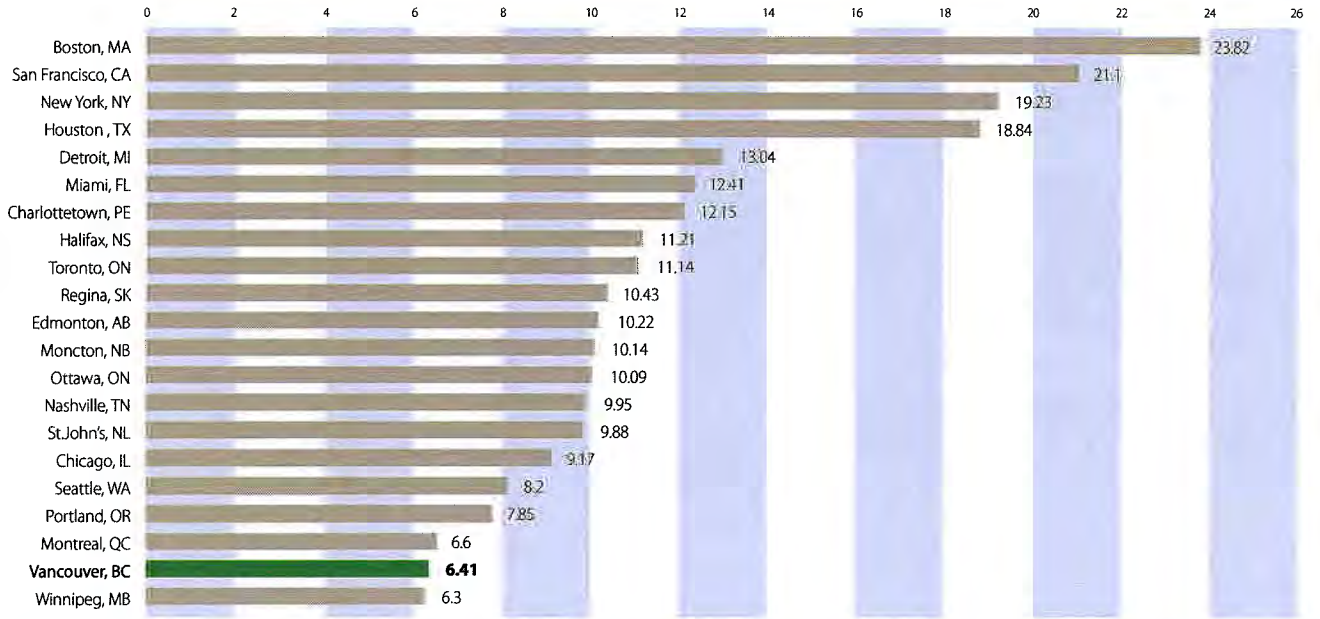
Bring Clean Power to Communities

British Columbia's electricity industry supports thousands of well-paying jobs, helps drive the economy and provides revenues to sustain public services. British Columbia's electricity industry already fosters economic development by implementing cost effective and reliable energy solutions in communities around the province. However, British Columbia covers almost one million square kilometres and electrification does not extend to all parts of our vast province.

Government and BC Hydro have established First Nation and remote community energy programs to implement alternative energy, energy efficiency, conservation and skills training solutions in a number of communities. The program focuses on expanding electrification services to as many as 50 remote and First Nations communities in British Columbia, enabling them to share in the benefits of a stable and secure supply of electricity. Government will put the policy framework in place and BC Hydro will implement the program over the next 10 years. The **Innovative Clean Energy Fund** can also support technological advancements to address the issue of providing a clean and secure supply of electricity to remote communities.

2006 Average Residential Electricity Price

Price (Canadian cents per kilowatt hour)



Source: Hydro Quebec comparison of Electricity Prices in Major North American Cities, April 2006

BRINGING CLEAN POWER TO ATLIN

Electricity in the remote community of Atlin in northwestern British Columbia is currently supplied by diesel generators. The First Nations and Remote Community Clean Energy Program is bringing clean power to Atlin.

The Taku Land Corporation, solely owned by the Taku River Tlingit First Nation will construct a two megawatt run-of-river hydroelectric project on Pine Creek, generating local economic benefits and providing clean power for Atlin. The Taku Land Corporation has entered into a 25 year Electricity Purchase Agreement with BC Hydro to supply electricity from the project to Atlin's grid. Over the course of the agreement, this will reduce greenhouse gas emissions by up to 150,000 tonnes as the town's diesel generators stand by.

The province is contributing $1.4 million to this $10 million project. This is the first payment from a $3.9 million federal contribution to British Columbia's First Nations and Remote Community Clean Energy Program. Criteria for federal funding included demonstrating greenhouse gas emissions reductions, cost-effectiveness, and partnerships with communities and industry.

Government will work with other agencies to maximize opportunities to develop, deploy and export British Columbia clean and alternative energy technologies.

POLICY ACTIONS

INVESTING IN INNOVATION

- **Establish the Innovative Clean Energy Fund to support the development of clean power and energy efficiency technologies in the electricity, alternative energy, transportation and oil and gas sectors.**
- **Implement a provincial Bioenergy Strategy which will build upon British Columbia's natural bioenergy resource advantages.**
- **Issue an expression of interest followed by a call for proposals for electricity from sawmill residues, logging debris and beetle-killed timber to help mitigate impacts from the provincial mountain pine beetle infestation.**

Innovative Clean Energy Fund

British Columbia's increasing energy requirements and our ambitious greenhouse gas emission reduction and clean energy targets require greater investment and innovation in the area of alternative energy by both the public and private sector.

To lead this effort, the government will establish an **Innovative Clean Energy Fund** of $25 million to help promising clean power technology projects succeed. The fund will be established through a small charge on energy utilities. The Minister of Energy, Mines and Petroleum Resources will consult with the energy utilities on the implementation of this charge.

Proponents of projects that will be supported through the fund will be encouraged to seek additional contributions from other sources. Government's new **Innovative Clean Energy Fund** will help make British Columbia a world leader in alternative energy and power technology. It will solve some of B.C.'s pressing energy challenges, protect our environment, help grow the economy, position the province as the place international customers turn to for key energy and environmental solutions, and assist B.C. based companies to showcase their products to world wide markets.

Following the advice of the Premier's Technology Council and the Alternative Energy and Power Technology Task Force, the fund will focus strictly on projects that:

- Address specific British Columbia energy and environmental problems that have been identified by government.
- Showcase B.C. technologies that have a strong potential for international market demand in other jurisdictions because they solve problems that exist both in B.C. and other jurisdictions.
- Support pre-commercial energy technology that is new, or commercial technologies not currently used in British Columbia.
- Demonstrate commercial success for new energy technologies.

Some problems that the fund could focus on include:

- Developing reliable power solutions for remote communities-particularly helping First Nations communities reduce their reliance on diesel generation for electricity.
- Advance conservation technologies to commercial application.
- Finding ways to convert vehicles to cleaner alternative fuels.
- Increasing the efficiency of power transmission through future grid technologies.
- Expanding the opportunities to generate power using alternative fuels (e.g.mountain pine beetle wood).

The British Columbia Bioenergy Strategy: Growing Our Natural Energy Advantage

Currently, British Columbia is leading Canada in the use of biomass for energy. The province has 50 per cent of Canada's biomass electricity generating capacity. In 2005, British Columbia's forest industry self-generated the equivalent of $150 million in electricity and roughly $1.5 billion in the form of heat energy. The use of biomass has displaced some natural gas consumption in the pulp and paper sector. The British Columbia wood pellet industry also enjoys a one-sixth share of the growing European Union market for bioenergy feedstock. The province will shortly release a bioenergy strategy that will build upon British Columbia's natural bioenergy resource advantages, industry capabilities and academic strength to establish British Columbia as a world leader in bioenergy development.

British Columbia's plan is to lead the bioeconomy in Western Canada with a strong and sustainable bioenergy sector. This vision is built on two guiding principles:

- Competitive, diversified forest and agriculture sectors.
- Strengthening regions and communities.

The provincial Bioenergy Strategy is aimed at:

- Enhancing British Columbia's ability to become electricity self-sufficient.
- Fostering the development of a sustainable bioenergy sector.
- Creating new jobs.
- Supporting improvements in air quality.
- Promoting opportunities to create power from mountain pine beetle-impacted timber.
- Positioning British Columbia for world leadership in the development and commercial adoption of wood energy technology.
- Advancing innovative solutions to agricultural and other waste management challenges.
- Encouraging diversification in the forestry and agriculture industries.
- Producing liquid biofuels to meet Renewable Fuel Standards and displace conventional fossil fuels.

Generating Electricity from Mountain Pine Beetle Wood: Turning Wood Waste into Energy

British Columbia is experiencing an unprecedented mountain pine beetle infestation that has affected several million hectares of trees throughout the province. This infestation is having a significant impact on forestry-based communities and industries, and heightens forest fire risk. There is a great opportunity to convert the affected timber to bioenergy, such as wood pellets and wood-fired electricity generation and cogeneration.

Through **The BC Energy Plan**, BC Hydro will issue a call for proposals for electricity from sawmill residues, logging debris and beetle-killed timber to help mitigate impacts from the provincial mountain pine beetle infestation.

MOUNTAIN PINE BEETLE INFESTATION: TURNING WOOD WASTE INTO ENERGY

British Columbia is experiencing an unprecedented mountain pine beetle infestation that has affected several million hectares of trees throughout the province. This infestation is having a significant economic impact on B.C.'s forestry industry and the many communities it helps to support and sustain. The forest fire risk to these communities has also risen as a result of their proximity to large stands of "beetle-killed" wood.

B.C. has developed a bioenergy strategy to promote new sources of sustainable and renewable energy in order to take advantage of the vast amounts of pine beetle-infested timber and other biomass resources. In the future, bioenergy will help meet our electricity needs, supplement conventional natural gas and petroleum supplies, maximize job and economic opportunities and protect our health and environment.

The production of wood pellets is already a mature industry in British Columbia. Industry has produced over 500,000 tonnes of pellets and exported about 90 per cent of this product overseas in 2005, primarily to the European thermal power industry. Through **The BC Energy Plan**, BC Hydro will issue a call for proposals for further electricity generation from wood residue and mountain pine beetle-infested timber.

GOVERNMENT TO USE HYBRID VEHICLES ONLY

The provincial government is continuing the effort to reduce greenhouse gas emissions and overall energy consumption.

As part of this effort, government has more than tripled the size of its hybrid fleet since 2005 to become one of the leaders in public sector use of hybrid cars.

Hybrids emit much less pollution than conventional gas and diesel powered vehicles and thus help to reduce greenhouse gases in our environment. They can also be more cost-effective as fuel savings offset the higher initial cost.

As of 2007, all new cars purchased or leased by the B.C. government are to be hybrid vehicles. The province also has new financial incentives to help local governments shift to hybrid vehicle fleets and help retrofit diesel vehicles.

Addressing Greenhouse Gas Emissions from Transportation

The BC Energy Plan: A Vision for Clean Energy Leadership takes a first step to incorporate transportation issues into provincial energy policy. Transportation is a major contributor to climate change and air quality problems. It presents other issues such as traffic congestion that slows the movement of goods and people. The fuel we use to travel around the province accounts for about 40 per cent of British Columbia's greenhouse gas emissions. Every time we drive or take a vehicle that runs on fossil fuels, we add to the problem, whether it's a train, boat, plane or automobile. Cars and trucks are the biggest source of greenhouse gas emissions and contribute to reduced air quality in urban areas.

The government is committed to reducing greenhouse gas emissions from the transportation sector and has committed to adopting California's tailpipe emission standards from greenhouse gas emissions and champion the national adoption of these standards.

British Columbians want a range of energy options for use at home, on the road and in day-to-day life. Most people use gasoline or diesel to keep their vehicles moving, but there are other options that improve our air quality and reduce greenhouse gas emissions.

Natural gas burns cleaner than either gasoline or propane, resulting in less air pollution. Fuel cell vehicles are propelled by electric motors powered by fuel cells, devices that produce electricity from hydrogen without combustion.

Cars that run on blends of renewable biofuels like ethanol and biodiesel emit lower levels of greenhouse gases and air pollutants. Electricity can provide an alternative to gasoline vehicles when used in hybrids and electric cars.

By working with businesses, educational institutions, non-profit organizations and governments, new and emerging transportation technologies can be deployed more rapidly at home and around the world. British Columbia will focus on research and development, demonstration projects, and marketing strategies to promote British Columbia's technologies to the world.

Implementing a Five Per Cent Renewable Fuel Standard for Diesel and Gasoline

The BC Energy Plan demonstrates British Columbia's commitment to environmental sustainability and economic growth by taking a lead role in promoting innovation in the transportation sector to reduce greenhouse gas emissions, improve air quality and help improve British Columbians' health and quality of life in the future. The plan will implement a five per cent average renewable fuel standard for diesel by 2010 to help reduce emissions and advance the domestic renewable fuel industry. It will further support the federal action of increasing the ethanol content of gasoline to five per cent by 2010. The plan will also see the adoption of quality parameters for all renewable fuels and fuel blends that are appropriate for Canadian weather conditions in cooperation with North American jurisdictions. These renewable fuel standards are a major component and first step towards government's goal of reducing the carbon intensity of all passenger vehicles by 10 per cent by 2020.

Government will implement a five per cent average renewable fuel standard for diesel by 2010 to help reduce emissions and advance the domestic renewable fuel industry.

A Commitment to Extend British Columbia's Ground-breaking Hydrogen Highway

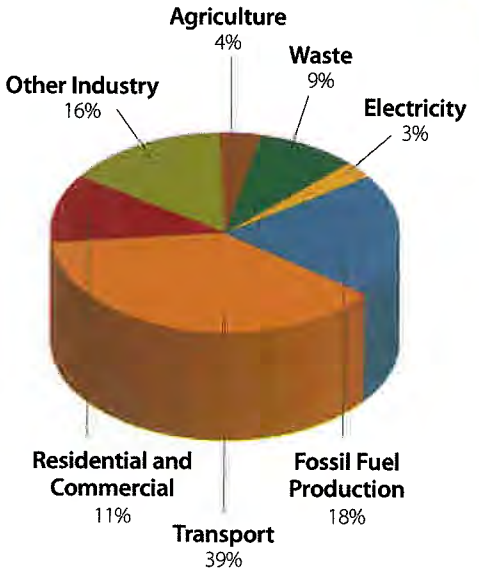
British Columbia is a world leader in transportation applications of the Hydrogen Highway, including the design, construction and safe operation of advanced hydrogen vehicle fuelling station technology. The Hydrogen Highway is a large scale, coordinated demonstration and deployment program for hydrogen and fuel cell technologies.

Vancouver's Powertech Labs established the world's first fast-fill, high pressure hydrogen fuelling station. The station anchors the Hydrogen Highway, which runs from Victoria through Surrey to Vancouver, North Vancouver, Squamish, and Whistler. Additional hydrogen fuelling stations are now in operation in Victoria and at the University of British Columbia.

The goal is to demonstrate and deploy various technologies and to one day see hydrogen filling stations around the province, serving drivers of consumer and commercial cars, trucks, and buses.

The unifying vision of the province's hydrogen and fuel cell strategy is to promote fuel cells and hydrogen technologies as a means of moving towards a sustainable energy future, increasing energy efficiency and reducing air pollutants and greenhouse gases. The Hydrogen Highway is targeted for full implementation by 2010. Canadian hydrogen and fuel cell companies have invested over $1 billion over the last five years, most of that in B.C. A federal-provincial partnership will be investing $89 million for fuelling stations and the world's first fleet of 20 fuel cell buses.

British Columbia will continue to be a leader in the new hydrogen economy by taking actions such as a fuel cell bus fleet deployment, developing a regulatory framework for micro-hydrogen applications, collaborating with neighbouring jurisdictions on hydrogen, and, in the long term, establishing a regulatory framework for hydrogen production, vehicles and fuelling stations.



B.C. Greenhouse Gas Emissions by Sector

(Based on 2004 data)
Source: Ministry of Environment

Cars and trucks are the biggest source of greenhouse gas emissions and reduce the quality of air in urban areas.

POLICY ACTIONS

ADDRESSING GREENHOUSE GAS EMISSIONS FROM TRANSPORTATION AND INCREASING INNOVATION

- Implement a five per cent average renewable fuel standard for diesel by 2010 to help reduce emissions and advance the domestic renewable fuel industry.
- Support the federal action of increasing the ethanol content of gasoline to five per cent by 2010 and adopt quality parameters for all renewable fuels and fuel blends that are appropriate for Canadian weather conditions in cooperation with North American jurisdictions.
- Develop a leading hydrogen economy by continuing to support the Hydrogen and Fuel Cell Strategy for British Columbia.
- Establish a new, harmonized regulatory framework by 2010 for hydrogen by working with governments, industry and hydrogen alliances.

Vehicles that run on electricity, hydrogen and blends of renewable biofuels like ethanol and biodiesel emit lower levels of greenhouse gases and air pollutants.

LOCALMOTION FUND: REDUCING AIR POLLUTION IN YOUR COMMUNITY

The province has committed $40 million over four years to help build cycling and pedestrian pathways, improve safety and accessibility, and support children's activity programs in playgrounds.

This fund will help local government shift to hybrid vehicle fleets and help retrofit diesel vehicles which will help reduce air pollution and ensure vibrant and environmentally sustainable communities. This investment will also include expansion of rapid transit and support fuel cell vehicles.

Promote Energy Efficiency and Alternative Energy

It is important for British Columbians to understand the appropriate uses of different forms of energy and utilize the right fuel, for the right activity at the right time. There is the potential to promote energy efficiency and alternative energy supplemented by natural gas. Combinations of alternative energy sources with natural gas include solar thermal and geothermal. Working with municipalities, utilities and other stakeholders the provincial government will promote energy efficiency and alternative energy systems, such as solar thermal and geothermal throughout the province.

Environmental Leadership in Action

The BC Energy Plan: A Vision for Clean Energy Leadership complements other related cross-government initiatives that include supporting transportation demand management, reducing traffic congestion and better integrating land use and transportation planning. These plans include actions across a broad range of activities. Some key initiatives and recent announcements include:

- Extending the tax break on hybrid vehicle purchases beyond the current March 2008 deadline.
- Government to purchase hybrid vehicles exclusively.
- Reducing diesel emissions through new financial incentives to help municipalities shift to hybrid vehicle fleets and retrofit diesel vehicles with cleaner technologies.
- Green Ports:
  - Working with ports and the shipping sector to reduce emissions from their activities and marine vessels.
  - The Port of Vancouver has established idle reduction zones and has reduced truck emissions with its container reservation system which has reduced average wait times from two hours to approximately 20 minutes.
  - The port is also evaluating port-side electrification which would see vessels using shore-side electrical power while berthed rather than diesel power.
- Improving upon the monitoring and reporting of air quality information.
- Highway Infrastructure and Rapid Transit Infrastructure funding including the Gateway Program, the Border Infrastructure Program, high occupancy vehicle lanes, construction of the Rapid Transit Canada Line linking Richmond, the Vancouver International Airport and Vancouver, and the Rapid Transit Evergreen Line linking Burnaby to Coquitlam.
- Expanding the AirCare on the Road Program to the Lower Fraser Valley and other communities.
- Implementing the LocalMotion Program for capital projects to improve physical fitness and safety, reduce air pollution and meet the diverse needs of British Columbians.

A Choice of Electricity Options

The range of supply options, both large and small, for British Columbia include:

Bioenergy: Bioenergy is derived from organic biomass sources such as wood residue, agricultural waste, municipal solid waste and other biomass and may be considered a carbon-neutral form of energy, because the carbon dioxide released by the biomass when converted to energy is equivalent to the amount absorbed during its lifetime.

A number of bioenergy facilities operate in British Columbia today. Many of these are "cogeneration" plants that create both electricity and heat for on-site use and in some cases, sell surplus electricity to BC Hydro.

Reliability[1]: FIRM
Estimated Cost[5]: $75 – $91

Coal Thermal Power: The BC Energy Plan establishes a zero emission standard for greenhouse gas emissions from coal-fired plants. This will require proponents of new coal facilities to employ clean coal technology with carbon capture and sequestration to ensure there are no greenhouse gas emissions.

Reliability[1]: FIRM
Estimated Cost[5 6]: $67– $82

Geothermal: Geothermal power is electricity generated from the earth. Geothermal power production involves tapping into pockets of superheated water and steam deep underground, bringing them to the surface and using the heat to produce steam to drive a turbine and produce electricity. British Columbia has potential high temperature (the water is heated to more than 200 degrees Celsius) geothermal resources in the coastal mountains and lower temperature resources in the interior, in northeast British Columbia and in a belt down the Rocky Mountains. Geothermal energy's two main advantages are its consistent supply, and the fact that it is a clean, renewable source of energy.

Reliability[1]: FIRM
Estimated Cost[2]: $44 - $60

Hydrogen and Fuel Cell Technology:
British Columbia companies are recognized globally for being leaders in hydrogen and fuel cell technology for mobile, stationary and micro applications. For example, BC Transit's fuel cell buses are planned for deployment in Whistler in 2009.

Reliability[1]: FIRM
Estimated Cost[2]: n/a

[1] Reliability refers to energy that can be depended on to be available whenever required
[2] Source: BC Hydro's 2006 IEP Volume 1 of 2 page 5-6
[3] Based on a 500 MW super ciritcal pulverized coal combustion unit. The BC Energy Plan requires coal power to meet zero GHG emissions
[4] Based on a 250 MW combined cycle gas turbine plant. The BC Energy Plan requires coal power to meet zero GHG emissions
[5] Source: BC Hydro's F2006 Open Call for Power Report
[6] These costs do not reflect the costs of zero GHG emissions for coal thermal power

GOVERNMENT'S COMMITMENT TO THE ENVIRONMENT – THE ENVIRONMENTAL ASSESSMENT PROCESS

The environmental assessment process in British Columbia is an integrated review process for major projects that looks at potential environmental, community and First Nation, health and safety, and socioeconomic impacts. Through the environmental assessment process, the potential effects of a project are identified and evaluated early, resulting in improved project design and helping to avoid costly mistakes for proponents, governments, local communities and the environment.

An assessment is begun when a proposed project that meets certain criteria under the *Environmental Assessment Act* makes an application for an environmental assessment certificate. Each assessment will usually include an opportunity for all interested parties to identify issues and provide input; technical studies of the relevant environmental, social, economic, heritage and/or health effects of the proposed project; identification of ways to prevent or minimize undesirable effects and enhance desirable effects; and consideration of the input of all interested parties in compiling the assessment findings and making decisions about project acceptability. The review is concluded when a decision is made to issue or not issue an environmental assessment certificate. Industrial, mining, energy, water management, waste disposal, food processing, transportation and tourist destination resort projects are generally subject to an environmental assessment.

ELECTRICITY CHOICES

WHAT IS THE DIFFERENCE BETWEEN FIRM AND INTERMITTENT ELECTRICITY?

Firm electricity refers to electricity that is available at all times even in adverse conditions. The main sources of reliable electricity in British Columbia include large hydroelectric dams, and natural gas. This differs from intermittent electricity, which is limited or is not available at all times. An example of intermittent electricity would be wind which only produces power when the wind is blowing.

Large Hydroelectric Dams: The chief advantage of a hydro system is that it provides a reliable supply with both dependable capacity and energy, and a renewable and clean source of energy. Hydropower produces essentially no carbon dioxide.

Site C is one of many resource options that can help meet BC Hydro's customers' electricity needs. No preferred option has been selected at this time; however; it is recognized that the Province will need to examine opportunities for some large projects to meet growing demand.

As part of **The BC Energy Plan**, BC Hydro and the Province will enter into initial discussions with First Nations, the Province of Alberta and communities to discuss Site C to ensure that communications regarding the potential project and the processes being followed are well known. The purpose of this step is to engage the various parties up front to obtain input for the proposed engagement process. The decision-making process on Site C includes public consultation, environmental impact assessments, obtaining a Certificate of Public Convenience and Necessity, obtaining an Environmental Assessment Certificate and necessary environmental approvals, and approval by Cabinet.

Reliability[1]: FIRM
Estimated Cost[2]: $43 - $62

Natural Gas: Natural gas is converted into electricity through the use of gas fired turbines in medium to large generating stations; particularly high efficiencies can be achieved through combining gas turbines with steam turbines in the combined cycle and through reciprocating engines and mini and macro turbines. Combined cycle power generation using natural gas is the cleanest source of power available using fossil fuels. Natural gas provides a reliable supply with both dependable capacity and firm energy.

Reliability[1]: FIRM
Estimated Cost[2 6]: $48 - $100

Small Hydro: This includes run-of-river and micro Hydro. These generate electricity without altering seasonal flow characteristics. Water is diverted from a natural watercourse through an intake channel and pipeline to a powerhouse where a turbine and generator convert the kinetic energy in the moving water to electrical energy.

Twenty-nine electricity purchase agreements were awarded to small waterpower producers by BC Hydro in 2006. These projects will generate approximately 2,851 gigawatt hours of electricity annually (equivalent to electricity consumed by 285,000 homes in British Columbia). There are also 32 existing small hydro projects in British Columbia that generate 3,500 gigawatt hours (equivalent to electricity consumed by 350,000 homes in British Columbia).

Reliability[1]: INTERMITTENT
Estimated Cost[3]: $60 – $95

Solar: With financial support from the Ministry of Energy, Mines and Petroleum Resources, the "Solar for Schools" program has brought clean solar photovoltaic electricity to schools in Vernon, Fort Nelson, and Greater Victoria.

The BC Sustainable Energy Association is leading a project which targets installing solar water heaters on 100,000 rooftops across British Columbia.

Reliability[1]: INTERMITTENT
Estimated Cost[2]: $700 - $1700

Tidal Energy: A small demonstration project has been installed at Race Rocks located west-southwest of Victoria. The Lester B. Pearson College of the Pacific, the provincial and federal government, and industry have partnered to install and test a tidal energy demonstration turbine at Race Rocks. The project will generate about 77,000 kilowatt hours on an annual basis (equivalent to electricity consumed by approximately eight homes).

Reliability[1]: INTERMITTENT
Estimated Cost[2]: $100 - $360

Wind: British Columbia has abundant, widely distributed wind energy resources in three areas: the Peace region in the Northeast; Northern Vancouver Island; and the North Coast. Wind is a clean and renewable source that does not produce air or water pollution, greenhouse gases, solid or toxic wastes.

Three wind generation projects have been offered power purchase contracts in BC Hydro's 2006 Open Call for Power. These three projects will have a combined annual output of 979 gigawatt hours of electricity (equivalent to electricity consumed by 97,900 homes).

Reliability[1]: INTERMITTENT
Estimated Cost[5]: $71 – $74

[1] Reliability refers to energy that can be depended on to be available whenever required
[2] Source: BC Hydro's 2006 IEP Volume 1 of 2 page 5-6
[3] Based on a 500 MW super ciritcal pulverized coal combustion unit. The BC Energy Plan requires coal power to meet zero GHG emissions
[4] Based on a 250 MW combined cycle gas turbine plant.
[5] Source: BC Hydro's F2006 Open Call for Power Report
[6] These costs do not reflect the costs of zero net GHG emissions for natural gas

ELECTRICITY CHOICES

RACE ROCKS TIDAL ENERGY PROJECT

Announced in early 2005, this demonstration project between the provincial and federal governments, industry, and Pearson College is producing zero-emission tidal power at the Race Rocks Marine Reserve on southern Vancouver Island. Using a current-driven turbine submerged below the ocean surface, the project is producing about 77,000 kilowatt hours of electricity per year, enough to meet the needs of approximately eight households. The knowledge gained about tidal energy will help our province remain at the forefront of clean energy generation technology.

Table 1: Summary of Resource Options

Description	Estimated Cost[1] $ /megawatt hour	Reliable[2]	Greenhouse gas emissions[3] tonnes per gigawatt hour
Energy conservation/ efficiency	32 – 76	Yes	0
Large hydroelectric	43 – 62	Yes	0
Natural gas	48 – 100[4]	Yes	0 – 350[4,8]
Coal	67 – 82[5,9]	Yes	0 – 855[5,9]
Biomass	75 – 91[10]	Yes	0 – 500[6]
Geothermal	44 – 60	Yes	0 – 10
Wind	71 – 74[10]	Depends on the availability and speed of wind	0
Run-of-river small hydro	60 – 95[10]	Depends on the flow of water which varies throughout the year	0
Ocean (wave and tidal)	100 – 360[7]	Future supply option which has great potential for British Columbia	0
Solar	700 – 1700[7]	Depends on location, cloud cover, season, and time of day	0

[1] Source: BC Hydro's 2006 Integrated Electricity Plan Volume 1 of 2, page 5-6
[2] Reliability refers to energy that can be depended on to be available whenever required
[3] Source: BC Hydro's 2006 Integrated Electricity Plan, Volume 2 of 2, Appendix F page 5-14 and Table 10-2
[4] Based on a 250 MW combined cycle gas turbine plant
[5] Based on a 500 MW supercritical pulverized coal combustion unit
[6] GHG are 0 for wood residue and landfill gas. GHG is 500 tonnes per gigawatt hour for municipal solid waste
[7] Source: BC Hydro's 2004 Integrated Electricity Plan, page 69
[8] The BC Energy Plan requires natural gas plants to offset to zero net greenhouse gas emissions. These costs do not reflect the costs of zero net GHG emissions
[9] The BC Energy Plan requires zero greenhouse gas emissions from any coal thermal electricity facilities
The costs do not include the costs of requiring zero emissions from coal thermal power
[10] Source: BC Hydro's F2006 Open Call for Power Report

The majority of B.C.'s electricity requirements over the next 10 years can be achieved through increased conservation by all British Columbians and new electricity from independent power producers.

British Columbia's Strength in Electricity Diversity

British Columbia is truly fortunate to have a wide variety of future supply options available to meet our growing demand for energy. A cost effective way to meet that demand is to conserve energy and be more energy efficient. However, British Columbia will still need to bring new power on line to meet demand growth in the years ahead. In order to ensure we have this critical resource available to British Columbians when they need it, government will be looking to secure a range of made-in-B.C. power to serve British Columbians in the years ahead.

Government's goal is to encourage a diverse mix of resources that represent a variety of technologies. Some resource technologies, such as large and small hydro, thermal power, wind and geothermal provide well-established, commercially available sources of electricity. Other emerging technologies that are not yet widely used include large ocean wave and tidal power, solar, hydrogen and advanced coal technologies.

2004 Total Electricity Production by Source (% of total)

	Other Renewables	Hydro Electric	Nuclear	Waste and Biomass	Natural Gas	Diesel Oil	Coal	TOTAL
British Columbia	**0.0**	**92.8**	**0.0**	**1.0**	**6.0**	**0.2**	**0.0**	**100**
Alberta	2.3	4.4	0.0	0.0	12.0	2.6	78.7	100
Australia	0.3	6.9	0.0	0.6	12.3	0.70	79.2	100
California	10.7	17.0	14.5	0.0	37.7	0.0	20.1	100
Denmark	16.3	0.1	0.0	8.8	24.7	4.0	46.1	100
Finland	0.4	17.6	26.5	12.4	14.9	0.7	27.5	100
France	0.2	11.3	78.3	1.0	3.2	1.0	5.0	100
Germany	4.2	4.5	27.1	2.6	10.0	1.6	50.0	100
Japan	0.4	9.5	26.1	1.9	22.6	12.3	27.2	100
Norway	0.3	98.8	0.0	0.5	0.3	0.0	0.1	100
Ontario	1.8	24.8	49.7	0.0	5.2	0.5	18.0	100
Oregon	2.3	64.4	0.0	0.0	26.3	0.1	6.9	100
Quebec	0.7	94.5	3.2	0.0	0.1	1.5	0.0	100
United Kingdom	0.5	1.9	20.2	2.1	40.3	1.2	33.8	100
Washington	2.3	70.0	8.8	0.0	8.6	0.1	10.2	100

SHARING SOLUTIONS ON ELECTRICITY

The BC Energy Plan has a goal that most of B.C.'s electricity requirements over the next 10 years can be achieved through increased conservation and energy efficiency by all British Columbians, coupled with generation by independent power producers. However, these new projects take time to plan and implement. In addition, many of these sources provide limited amounts of firm supply. The province will also need to consider options for new, large scale sources to meet forecasted demand growth in the next 10 to 20 years. Large scale options could include Site C, large biomass facilities, clean coal or natural gas plants. As with all large scale undertakings, these kinds of projects will require years of lead time to allow for careful planning, analysis, consultation and construction.

Perhaps the biggest challenge facing British Columbians is simply to begin choosing our electricity future together. Demand for electricity is projected to grow by up to 45 per cent over the next 20 years. To meet this projected growth we will need to conserve more and obtain more electricity from small power producers and large projects. Given the critical importance of public participation and stakeholder involvement in addressing the challenges and choices of meeting our future electricity needs, government and BC Hydro will seek and share solutions.

Rapid expansion of our energy sector means a growing number of permanent, well-paying employment opportunities are available.

Taking Action to Meet the Demand for Workers

The energy sector has been a major contributor to British Columbia's record economic performance since 2001. **The BC Energy Plan** focuses on four under-represented groups that offer excellent employment potential: Aboriginal people, immigrants, women and youth.

At the same time, the energy sector must overcome a variety of skills training and labour challenges to ensure future growth.

These challenges include:

- An aging workforce that upon retirement will leave a gap in experience and expertise.
- Competition for talent from other jurisdictions.
- Skills shortages among present and future workers.
- Labour market information gaps due to a lack of in-depth study.
- The need to coordinate immigration efforts with the federal government.
- The need for greater involvement of under-represented energy sector workers such as Aboriginal people, immigrants, women, and youth.
- A highly mobile workforce that moves with the opportunities.
- The need to improve productivity and enhance competitiveness.

Innovative, practical and timely skills training, and labour management is required to ensure the energy sector continues to thrive. As part of **The BC Energy Plan**, government will work collaboratively with industry, communities, Aboriginal people, education facilities, the federal government and others to define the projected demand for workers and take active measures to meet those demands.

Attract Highly Skilled Workers

Demographics show that those born at the height of the baby boom are retired or nearing retirement, leaving behind a growing gap in skills and expertise. Since this phenomenon is taking place in most western nations, attracting and retaining skilled staff is highly competitive.

To ensure continued energy sector growth, we need to attract workers from outside the province, particularly for the electricity, oil and gas, and heavy construction industries where the shortage is most keenly felt. At this time, a significant increase in annual net migration of workers from other provinces and from outside Canada is needed to complement the existing workforce.

Government and its partners are developing targeted plans to attract the necessary workers. These plans will include marketing and promoting energy sector jobs as a career choice.

Develop a Robust Talent Pool of Workers

It is vital to provide the initial training to build a job-ready talent pool in British Columbia, as well as the ongoing training employees need to adapt to changing energy sector technologies, products and requirements. We can ensure a thriving pool of talent in British Columbia by retraining skilled employees who are without work due to downturns in other industries. Displaced workers from other sectors and jurisdictions may require some retraining and new employees may need considerable skills development.

Another way to help ensure there are enough skilled energy sector workers in the years ahead is to educate and inform young people today. By letting high school students know about the opportunities, they can consider their options and make the appropriate training and career choices. Government will work to enhance information relating to energy sector activities in British Columbia's school curriculum in the years ahead.

Retain Skilled Workers

Around the world, energy facility construction and operations are booming, creating fierce, global competition for skilled workers. While British Columbia has much to offer, it is critical that our jurisdiction presents a superior opportunity to these highly skilled and mobile workers. That is why we need to ensure our workplaces are safe, fair and healthy and our communities continue to offer an unparalleled lifestyle with high quality health care and education, affordable housing, and readily available recreation opportunities in outstanding natural settings.

Inform British Columbians

To be effective in filling energy sector jobs with skilled workers, British Columbians need to be informed and educated about the outstanding opportunities available. As part of **The BC Energy Plan**, a comprehensive public awareness and education campaign based on sound labour market analysis will reach out to potential energy sector workers. This process will recognize and address both the potential challenges such as shift work and remote locations as well as the opportunities, such as obtaining highly marketable skills and earning excellent compensation.

Be Among the Most Competitive Oil and Gas Jurisdictions in North America

Since 2001, British Columbia's oil and gas sector has grown to become a major force in our provincial economy, employing tens of thousands of British Columbians and helping to fuel the province's strong economic performance. In fact, investment in the oil and gas sector was $4.6 billion in 2005. The oil and gas industry contributes approximately $1.95 billion annually or seven per cent of the province's annual revenues.

The BC Energy Plan is designed to take B.C.'s oil and gas sector to the next level to enhance a sustainable, thriving and vibrant oil and gas sector in British Columbia. With a healthy, competitive oil and gas sector comes the opportunity to create jobs and build vibrant communities with increased infrastructure and services, such as schools and hospitals. Of particular importance is an expanding British Columbia-based service sector.

There is a lively debate about the peak of the world's oil and gas production and the impacts on economies, businesses and consumers. A number of countries, such as the UK, Norway and the USA, are experiencing declining fossil fuel production from conventional sources. Energy prices, especially oil prices have increased and are more volatile than in the past. As a result, the way energy is produced and consumed will change, particularly in developed countries.

POLICY ACTIONS

ENVIRONMENTALLY RESPONSIBLE OIL AND GAS DEVELOPMENT

- Eliminate all routine flaring at oil and gas producing wells and production facilities by 2016 with an interim goal to reduce flaring by half (50 per cent) by 2011.
- Establish policies and measures to reduce air emissions in coordination with the Ministry of Environment.
- Best coalbed gas practices in North America. Companies will not be allowed to surface discharge produced water. Any re-injected produced water must be injected well below any domestic water aquifer.
- Enhance the Oil and Gas Environmental Stewardship Program, ensuring sound environmental, land and resource management.

The plan is aimed at enhancing the development of conventional resources and stimulating activity in relatively undeveloped areas such as the interior basins – particularly the Nechako Basin. It will also foster the development of unconventional resources such as as tight gas, shale gas, and coalbed gas. The plan will further efforts to work with the federal government, communities and First Nations to advance offshore opportunities.

The challenge for British Columbia in the future will be to continue to find the right balance of economic, environmental and social priorities to allow the oil and gas sector to succeed, while protecting our environment and improving our quality of life.

The New Relationship and Oil and Gas

Working together with local communities and First Nations, the provincial government will continue to share in the many benefits and opportunities created through the development of British Columbia's oil and gas resources.

Government is working to ensure that oil and gas resource management includes First Nations' interests, knowledge and values. Government has recently concluded consultation agreements for oil and gas resource development with First Nations in Northeast British Columbia. These agreements increase clarity in the process and will go a long way to enhancing our engagement with these First Nations.

Government will continue to pursue opportunities to share information and look for opportunities to facilitate First Nations' employment and participation in the oil and gas industry to ensure that Aboriginal people benefit from the continued growth and development of British Columbia's resources.

The BC Energy Plan adopts a triple bottom line approach to competitiveness, with an attractive investment climate, environmentally sustainable development of B.C.'s abundant resources, and by benefiting communities and First Nations.

While striving to be among the most competitive oil and gas jurisdictions in North America, the province will focus on maintaining and enhancing its strong competitive environment for the oil and gas industry. This encompasses the following components:

- A competitive investment climate.
- An abundant resource endowment.
- Environmental responsibility.
- Social responsibility.

Leading in Environmentally and Socially Responsible Oil and Gas Development

The BC Energy Plan emphasizes conservation, energy efficiency, and the environmental and socially responsible management of the province's energy resources. It outlines government's efforts to meet this objective by working collaboratively with involved and interested parties, including affected communities, landowners, environmental groups, First Nations, the regulator (the Oil and Gas Commission), industry groups and others. Policy actions will support ways to address air emissions, impacts on land and wildlife habitat, and water quality.

The oil and gas sector in British Columbia accounts for approximately 18 per cent of greenhouse gas air emissions in the province. The main sources of air emissions from the oil and gas sector are flaring, fugitive gases, gas processing and compressor stations. While these air emissions have long been part of the oil and gas sector, they have also been a source of major concern for oil and gas communities.

Eliminate Flaring from Oil and Gas Producing Wells and Production Facilities By 2016

Through **The BC Energy Plan**, government has committed to eliminate all routine flaring at oil and gas producing wells and production facilities by 2016 with an interim goal to reduce flaring by half (50 per cent) by 2011. In addition, government will adopt policies to reduce natural gas flaring and venting at test sites and pipelines, and encourage compressor station efficiency to cut back emissions. Government will also explore opportunities and new technologies for safe, underground disposal of carbon dioxide or sequestration from oil and gas facilities. Sequestration is considered a cost effective mitigation strategy in reducing carbon dioxide emissions.

Enhance Carbon Dioxide Sequestration in British Columbia

British Columbia is a member of the Plains CO2 Reduction (PCOR) Partnership composed of nearly 50 private and public sector groups from nine states and three Canadian provinces that is assessing the technical and economic feasibility of capturing and storing carbon dioxide emissions from stationary sources in western sedimentary basins.

B.C. is also a member of the West Coast Regional Carbon Sequestration Partnership, made up of west coast state and provincial government ministries and agencies. This partnership has been formed to pursue carbon sequestration opportunities and technologies.

To facilitate and foster innovation in sequestration, government will develop market oriented requirements with a graduated schedule. In consultation with stakeholders, a timetable will be developed along with increasing requirements for sequestration.

BRITISH COLUMBIA COMPANIES RECOGNIZED AS WORLD ENERGY TECHNOLOGY INNOVATORS

The leadership of British Columbian companies can be seen in all areas of the energy sector through innovative industry leading technologies.

Production of a new generation of chemical injection pump for use in the oil and gas industry is beginning. The pumps, developed and built in British Columbia, are the first solar powered precision injection pumps available to the industry. They will reduce emissions by replacing traditional gas powered injection systems for pipelines.

Other solar technologies developed in British Columbia provide modular power supplies in remote locations all over the globe for marine signals, aviation lights and road signs.

Roads in B.C. and around the world are hosting demonstrations of fuel cell vehicles built with British Columbia technology. Thanks to the first high pressure hydrogen fuelling station in the world, compatible fuel cell vehicles in B.C. can carry more fuel and travel farther than ever before.

The **Innovative Clean Energy Fund** will help to build B.C.'s technology cluster and keep us at the forefront of energy technology development.

OIL AND GAS

Government will work to improve oil and gas tenure policies as well as develop new guidelines to determine areas that require special consideration prior to tenure approval.

POLICY ACTIONS

OFFSHORE OIL AND GAS DEVELOPMENT

- Continue to work to lift the federal moratorium on offshore exploration and development and reiterate the intention to simultaneously lift the provincial moratorium.
- Work with the federal government to ensure that offshore oil and gas resources are developed in a scientifically sound and environmentally responsible way.
- Participate in marine and environmental planning to effectively manage marine areas and offshore oil and gas basins.
- Develop and implement a comprehensive community engagement program to establish a framework for a benefits sharing agreement resulting from offshore oil and gas development for communities, including First Nations.

Environmental Stewardship Program

In 2004, the Ministry of Energy, Mines and Petroleum Resources initiated the Oil and Gas Environmental Stewardship Program having two components: the Environmental Policy Program and the Environmental Resource Information Project. The Environmental Policy Program identifies and mitigates environmental issues in the petroleum sector focusing on policy development in areas such as environmental waste management, habitat enhancement, planning initiatives, wildlife studies for oil and gas priority areas and government best management practices. Some key program achievements include the completion of guidelines for regulatory dispersion modeling, research leading to the development of soil quality guidelines for soluble barium, a key to northern grasses and their restorative properties for remediated well sites, and moose and caribou inventories in Northeast British Columbia.

The Environmental Resource Information Project is dedicated to increasing opportunities for oil and gas development, through the collection of necessary environmental baseline information. These projects are delivered in partnership with other agencies, industry, communities and First Nations.

The BC Energy Plan enhances the important Oil and Gas Environmental Stewardship Program. This will improve existing efforts to manage waste and preserve habitat, and will establish baseline data as well as development and risk mitigation plans for environmentally sensitive areas. Barriers need to be identified and steps taken for remediation, progressive reclamation, and waste management.

Best Coalbed Gas Practices in North America

Government will continue to encourage coalbed gas development with the intent of demonstrating that British Columbia is a leading socially and environmentally responsible coalbed gas developing jurisdiction. Coalbed gas, also known as coalbed methane, is natural gas found in coal seams. It is one of the cleanest burning of all fossil fuels. Proponents wanting to develop coalbed gas must adopt the following best practices:

- Fully engage local communities and First Nations in all stages of development.
- Use the most advanced technology and practices that are commercially viable to minimize land and aesthetic disturbances.
- Companies will not be allowed to surface discharge produced water. Any re-injected produced water must be injected well below any domestic water aquifer.
- Meet any other conditions the Oil and Gas Commission may apply.
- Demonstrate the company's previous experience with coalbed gas development, and information must be made publicly available as to how the company plans to meet and be accountable for these best practices.

Ensuring Offshore Oil and Gas Resources are Developed in a Scientifically Sound and Environmentally Responsible Way

The BC Energy Plan includes actions related to the province's offshore oil and gas resources. Since 1972, Canada and British Columbia have each had a moratorium in place on offshore oil and gas exploration and development. With advanced technology and

British Columbia's oil and gas industry supports thousands of well-paying jobs, helps drive the economy and provides revenues to sustain public services.

positive experiences in other jurisdictions, a compelling case exists for assessing British Columbia's offshore resource potential.

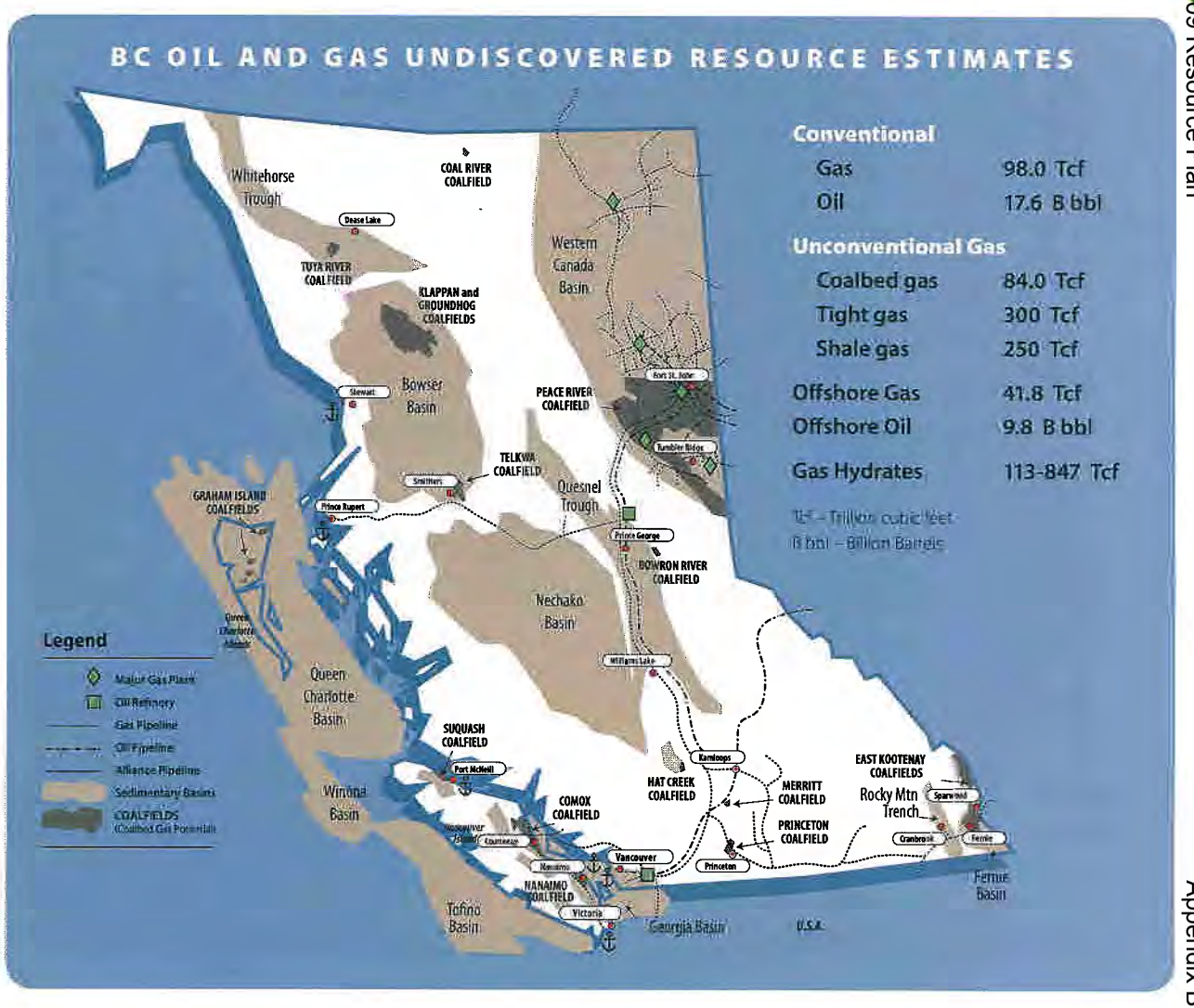
Government will work with coastal communities, First Nations, the federal government, environmental organizations, and others to ascertain the benefits and address the concerns associated with offshore oil and gas development.

Maintaining B.C.'s Competitive Advantage as an Oil and Gas Jurisdiction

British Columbia's oil and gas industry is thriving thanks to high resource potential, industry and service sector expertise, and a competitive investment climate that includes a streamlined regulatory environment. To attract additional investment in British Columbia's oil and gas industry, we need to compete aggressively with other jurisdictions that may offer lower taxes or other investment incentives.

Another key way to be more competitive is by spurring activity in underdeveloped areas while heightening activity in the northeast, where our natural gas industry thrives. The province will work with industry to develop new policies and technologies for enhanced resource recovery making, it more cost-effective to develop British Columbia's resources.

By increasing our competitiveness, British Columbians can continue to benefit from well-paying jobs, high quality social infrastructure and a thriving economy.



OIL AND GAS

British Columbia's Enormous Natural Gas Potential

The oil and gas sector will continue to play an important role in British Columbia's future energy security. Our province has enormous natural gas resource potential and opportunities for significant growth. **The BC Energy Plan** facilitates the development of B.C.'s resources.

British Columbia has numerous sedimentary basins, which contain petroleum and natural gas resources. In north-eastern British Columbia, the Western Canada Sedimentary Basin is the focus of our thriving natural gas industry. The potential resources in the central and northern interior of the province, the Nechako and Bowser Basins and Whitehorse Trough, have gone untapped.

NEEMAC: SUCCESS THROUGH COMMUNICATION

As energy, mining and petroleum resource development increases in northeast B.C., so too does the need for input from local governments, First Nations, community groups, landowners and other key stakeholders. In 2006, the Northeast Energy and Mines Advisory Committee (NEEMAC) was created to provide an inclusive forum for representative organizations to build relationships with each other, industry and government to provide input on Ministry policy, and recommend innovative solutions to stakeholder concerns.

Since its creation, NEEMAC has identified and explored priority concerns, and is beginning to find balanced solutions related to environmental, surface disturbance, access and landowner rights issues. The Ministry is committed to implementing recommendations that represent the broad interests of community, industry and government and expects that the committee will continue to provide advice on energy, mining and petroleum development issues in support of **The BC Energy Plan**.

The delayed evaluation and potential development of these areas is largely due to geological and physical obstructions that make it difficult to explore in the area. Volcanic rocks that overlay the sedimentary package combined with complex basin structures, have hindered development.

The BC Energy Plan is aimed at enhancing the development of conventional resources and stimulating activity in undeveloped areas such as the interior basins – particularly the Nechako Basin. It will also foster the development of unconventional resources and take a more stringent approach on coalbed gas to meet higher environmental standards.

Attracting Investment and Developing our Oil and Gas Resources

The BC Energy Plan promotes competitiveness by setting out a number of important regulatory and fiscal measures including: monitoring British Columbia's competitive ranking, considering a Net Profit Royalty Program, promoting a B.C. service sector, harmonizing and streamlining regulations, and developing a Petroleum Registry to examine royalty and tenure incentives, and undertaking geoscience programs.

Establishment of a Petroleum Registry

The establishment of a petroleum registry that functions as a central database will improve the quality and management of key volumetric, royalty and infrastructure information associated with British Columbia's oil and gas industry and promote competition while providing transparency around oil and gas activity.

An opportunity to increase competitiveness exists in British Columbia's Interior Basins – namely the Nechako, Bowser and Whitehorse Basins – where considerable resource potential is known to exist.

Increasing Access

In addition to regulatory and fiscal mechanisms, the plan addresses the need for improving access to resources. Pipelines and road infrastructure are critical factors in development and competitiveness. **The BC Energy Plan** calls for new investment in public roads and other infrastructure. It will see government establish a clear, structured infrastructure royalty program, combining road and pipeline initiatives and increasing development in under-explored areas that have little or no existing infrastructure.

Developing Conventional and Unconventional Oil and Gas Resources

To support investment in exploration, **The BC Energy Plan** calls for partnerships in research and development to establish reliable regional data, as well as royalty and tenure incentives. The goal is to attract investment, create well-paying jobs, boost the regional economy and produce economic benefits for all British Columbians. We can be more competitive by spurring activity in underdeveloped areas while heightening activity in the northeast where our natural gas industry thrives. The plan advocates working with industry to develop new policies and technology to enhance resource recovery, including oil in British Columbia.

Improve Regulations and Research

The province remains committed to continuous improvement in the regulatory regime and environmental management of conventional and unconventional oil and gas resources. The opportunities for enhancing exploration and production of tight gas, shale gas, and coalbed gas will also be assessed and supported by geoscience research and programs. **The BC Energy Plan** calls for collaboration with other government ministries, agencies, industry, communities and First Nations to develop the oil and gas resources in British Columbia.

Focus on Innovation and Technology Development

The BC Energy Plan also calls for supporting the development of new oil and gas technologies. This plan will lead British Columbia to become an internationally recognized centre for technological advancements and commercialization, particularly in environmental management, flaring, carbon sequestration and hydrogeology. The service sector has noted it can play an important role in developing and commercializing new technologies; however, the issue for companies is accessing the necessary funds.

THE HUB OF B.C.'S OIL AND GAS SECTOR

Oil and gas is benefiting all British Columbians - not just those living in major centres. Nowhere is this more apparent than in booming Fort St. John, which has rapidly become the oil and gas hub of the province. Since 2001, more than 1,400 people have moved to the community, an increase of 6.3 per cent and two per cent faster growth than the provincial average. Construction permits are way up - from $48.7 million in 2004, to $50.6 million in 2005, to over $123 million in 2006. In the past five years, over 1,000 new companies have been incorporated in Fort St. John, as young families, experienced professionals, skilled trades-people and many others move here from across the country.

OIL AND GAS

POLICY ACTIONS

BE AMONG THE MOST COMPETITIVE OIL AND GAS JURISDICTIONS IN NORTH AMERICA

- Pursue regulatory and fiscal competitiveness in support of being among the most competitive oil and gas jurisdictions in North America.
- Enhance infrastructure to support the development of oil and gas in British Columbia and address impediments to economic development such as transportation and labour shortages.
- Encourage the development of conventional and unconventional resources.
- Support the growth of British Columbia's oil and gas service sector.
- Promote exploration and development of the Interior basins with a priority focus on the Nechako Basin.
- Encourage the development of new technologies.
- Add value to British Columbia's oil and gas industry by assessing and promoting the development of additional gas processing facilities in the province.

Technology Transfer Incentive Program

A new Oil and Gas Technology Transfer Incentive Program will be considered to encourage the research, development and use of innovative technologies to increase recoveries from existing reserves and encourage responsible development of new oil and gas reserves. The program could recover program costs over time through increased royalties generated by expanded development and production of British Columbia's petroleum resources.

Scientific Research and Experimental Development

The BC Energy Plan supports the British Columbia Scientific Research and Experimental Development Program, which provides financial support for research and development leading to new or improved products and processes. Through credits or refunds, the expanded program could cover project costs directly related to commercially applicable research, and development or demonstration of new or improved technologies conducted in British Columbia that facilitate expanded oil and gas production.

Research and Development

The BC Energy Plan calls for using new or existing research and development programs for the oil and gas sector. Government will develop a program targeting areas in which British Columbia has an advantage such as well completion technology and hydrogeology.

A program to encourage oil and gas innovation and research in British Columbia's post-secondary institutions will be explored. These opportunities will be explored in partnership with the Petroleum Technology Alliance Canada and as part of the April 2006 Memorandum of Understanding between British Columbia and Alberta on Energy Research, Technology Development and Innovation.

Together with the Oil and Gas Centre of Excellence in Fort St. John, an oil and gas technology incubator, a site which provides innovators with space to build prototypes and carry out testing as well as providing business infrastructure and assistance accessing additional support will be established, allowing entrepreneurs to develop and test new innovations and commercialize new, innovative technologies and processes.

Nechako Initiative

The BC Energy Plan calls for government to partner with industry, the federal government, and Geoscience BC to undertake comprehensive research in the Nechako Basin and establish new data of the resource potential. It will include active engagement of communities and the development and implementation of a comprehensive pre-tenure engagement initiative for First Nations in the region. Specific tenures and royalties will be explored to encourage investment, as well as a comprehensive Environmental Information Program to identify baseline information needs in the area through consultations with government, industry, communities and First Nations.

By increasing our oil and gas industry's competitiveness, British Columbians can continue to benefit from well-paying jobs, high quality social infrastructure and a thriving economy.

Value-Added Opportunities

To improve competitiveness, The BC Energy Plan calls for a review of value-added opportunities in British Columbia. This will include a thorough assessment of the potential for processing facilities and petroleum refineries as well as petrochemical industry opportunities. The Ministry of Energy, Mines and Petroleum Resources will conduct an analysis to identify and address barriers and explore incentives required to encourage investment in gas processing in British Columbia. A working group of industry and government will develop business cases and report to the Minister by January 2008 with recommendations on the viability of a new petroleum refinery and petrochemical industry and measures, if any, to encourage investment.

Oil and Gas Service Sector

British Columbia's oil and gas service sector can also help establish our province as one of the most competitive jurisdictions in North America. The service sector has grown over the past four years and with increased activity, additional summer drilling, and the security of supply, opportunities for local companies will continue. Government can help maximize the benefits derived from the service sector by:

- Promoting British Columbia's service sector to the oil and gas industry through participation at trade shows and providing information to the business community.
- Identifying areas where British Columbian companies can play a larger role, expand into other provinces, and through procurement strategies.

The government also supports the Oil and Gas Centre of Excellence at the Fort St. John Northern Lights College campus, which will provide oil and gas, related vocational, trades, career and technical programs.

Improving Oil and Gas Tenures

Government will work to improve oil and gas tenure issuance policies as well as develop new guidelines to determine areas that require special consideration prior to tenure approval by the end of 2007. This will provide clear parameters for industry regarding areas where special or enhanced management practices are required. These measures will strike the important balance between providing industry with clarity and access to resources and the desire of local government, communities, landowners, stakeholders and First Nations for input into the oil and gas development process.

Create Opportunities for Communities and First Nations

Benefits for British Columbians from the Oil and Gas Sector

The oil and gas sector offers enormous benefits to all British Columbians through enhanced energy security, tens of thousands of good, well-paying jobs and tax revenues used to help fund our hospitals and schools. However, the day-to-day impact of the sector has largely been felt on communities and First Nations in British Columbia's northeast. Community organizations, First Nations, and landowners have communicated a desire for greater input into the pace and scope of oil and gas development in British Columbia.

Together with the Oil and Gas Centre of Excellence in Fort St. John, an oil and gas technology incubator will be established, allowing entrepreneurs to develop and test new innovations.

POLICY ACTIONS

WORKING WITH COMMUNITIES AND FIRST NATIONS

- Provide information about local oil and gas activities to local governments, First Nations, education and health service providers to inform and support the development of necessary social infrastructure.
- Work with First Nations to identify opportunities to participate in and benefit from oil and gas development.
- Support First Nations in providing cross-cultural training to agencies and industry.
- Improve working relationships among industry and local communities and landowners by clarifying and simplifying processes, enhancing dispute resolution methods, and offering more support and information.
- Examine oil and gas tenure policies and develop guidelines to determine areas that require special consideration prior to tenure approval.

Through **The BC Energy Plan**, government intends to develop stronger relationships with those affected by oil and gas development, including communities and First Nations. The aim is to work cooperatively to maximize benefits and minimize impacts. The plan supports improved working relationships among industry, local communities and landowners by increased and improved communication to clarify and simplify processes, enhancing dispute resolution methods, and offering more support and information.

The government will also continue to improve communications with local governments and agencies. Specifically, **The BC Energy Plan** calls for efforts to provide information about increased local oil and gas activities to local governments, education and health service providers to improve their ability to make timely decisions on infrastructure, such as schools, housing, and health and recreational facilities. By providing local communities and service providers with regular reports of trends and industry activities, they can more effectively plan for growth in required services and infrastructure.

Building Better Relationships with Landowners

The BC Energy Plan: A Vision for Clean Energy Leadership also supports improved working relationships between industry, local communities and landowners and First Nations. Landowners will be notified in a more timely way of sales of oil and gas rights on private land. Plain language information materials, including standardized lease agreements will be made available to help landowners deal with subsurface tenures and activity. There will be a review of the dispute resolution process between landowners and industry by the end of 2007. The existing setback requirements, the allowed distance of a well site from a residence, school or other public place, will also be examined. These measures seek to strike the important balance between providing industry with clarity and access to resources and the desire of local government, communities, landowners, stakeholders and First Nations for input into oil and gas development.

Working in Partnership with First Nations and Communities

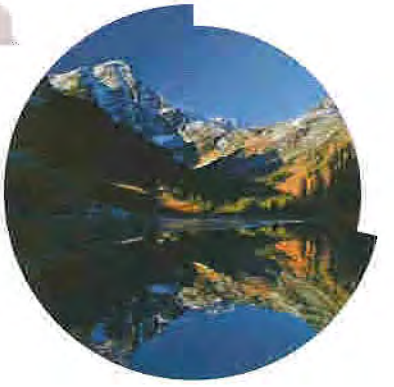
Government will work with First Nations communities to identify opportunities to benefit from oil and gas development. By developing a greater ability to participate in and benefit from oil and gas development, First Nations can play a much more active role in the industry. **The BC Energy Plan** also supports increasing First Nations role in the development of cross-cultural training initiatives for agencies and industry.

Conclusion

The BC Energy Plan: A Vision for Clean Energy Leadership sets the standard for proactively addressing the opportunities and challenges that lie ahead in meeting the energy needs for all the citizens of the province, now and in the future. Appendix A provides a detailed listing of the policy actions of the plan.

The BC Energy Plan will attract new investments, help develop and commercialize new technology, build partnerships with First Nations, and ensures a strong environmental focus.

British Columbia has a proud history of innovation that has resulted in 90 per cent of our power generation coming from clean sources. This plan builds on that foundation and ensures B.C. will be at the forefront of environmental and economic leadership for years to come.



APPENDIX A The BC Energy Plan: Summary of Policy Actions

ENERGY CONSERVATION AND EFFICIENCY

1. Set an ambitious conservation target, to acquire 50 per cent of BC Hydro's incremental resource needs through conservation by 2020.
2. Ensure a coordinated approach to conservation and efficiency is actively pursued in British Columbia.
3. Encourage utilities to pursue cost effective and competitive demand side management opportunities.
4. Explore with B.C. utilities new rate structures that encourage energy efficiency and conservation.
5. Implement Energy Efficiency Standards for Buildings by 2010.
6. Undertake a pilot project for energy performance labeling of homes and buildings in coordination with local and federal governments, First Nations, and industry associations.
7. New provincial public sector buildings will be required to integrate environmental design to achieve the highest standards for greenhouse gas emission reductions, water conservation and other building performance results such as a certified standard.
8. Develop an Industrial Energy Efficiency Program for British Columbia to address specific challenges faced by British Columbia's industrial sector.
9. Increase the participation of local governments in the Community Action on Energy Efficiency Program and expand the First Nations and Remote Community Clean Energy Program.

ELECTRICITY

10. Ensure self-sufficiency to meet electricity needs, including "insurance" by 2016.
11. Establish a standing offer for clean electricity projects up to 10 megawatts.
12. The BC Transmission Corporation is to ensure that British Columbia's transmission technology and infrastructure remains at the leading edge and has the capacity to deliver power efficiently and reliably to meet growing demand.
13. Ensure adequate transmission system capacity by developing and implementing a transmission congestion relief policy.
14. Ensure that the province remains consistent with North American transmission reliability standards.
15. Continue public ownership of BC Hydro and its heritage assets, and the BC Transmission Corporation.
16. Establish the existing heritage contract in perpetuity.
17. Invest in upgrading and maintaining the heritage asset power plants and the transmission lines to retain the ongoing competitive advantage these assets provide to the province.
18. All new electricity generation projects will have zero net greenhouse gas emissions.
19. Zero net greenhouse gas emissions from existing thermal generation power plants by 2016.
20. Require zero greenhouse gas emissions from any coal thermal electricity facilities.
21. Ensure clean or renewable electricity generation continues to account for at least 90 per cent of total generation.
22. Government supports BC Hydro's proposal to replace the firm energy supply from the Burrard Thermal plant with other resources. BC Hydro may choose to retain Burrard for capacity purposes after 2014.
23. No nuclear power.
24. Review BC Utilities Commissions' role in considering social and environmental costs and benefits.
25. Ensure the procurement of electricity appropriately recognizes the value of aggregated intermittent resources.
26. Work with BC Hydro and parties involved to continue to improve the procurement process for electricity.
27. Pursue Government and BC Hydro's planned Remote Community Electrification Program to expand or take over electricity service to remote communities in British Columbia.
28. Ensure BC Hydro considers alternative electricity sources and energy efficiency measures in its energy planning for remote communities.

ALTERNATIVE ENERGY

29. Establish the **Innovative Clean Energy Fund** to support the development of clean power and energy efficiency technologies in the electricity, alternative energy, transportation and oil and gas sectors.
30. Implement a provincial Bioenergy Strategy which will build upon British Columbia's natural bioenergy resource advantages.
31. Issue an expression of interest followed by a call for proposals for electricity from sawmill residues, logging debris and beetle-killed timber to help mitigate impacts from the provincial mountain pine beetle infestation.
32. Implement a five per cent average renewable fuel standard for diesel by 2010 to help reduce emissions and advance the domestic renewable fuel industry.
33. Support the federal action of increasing the ethanol content of gasoline to five per cent by 2010 and adopt quality parameters for all renewable fuels and fuel blends that are appropriate for Canadian weather conditions in cooperation with North American jurisdictions.
34. Develop a leading hydrogen economy by continuing to support the Hydrogen and Fuel Cell Strategy for British Columbia.
35. Establish a new, harmonized regulatory framework by 2010 for hydrogen by working with governments, industry and hydrogen alliances.

OIL AND GAS

36. Eliminate all routine flaring at oil and gas producing wells and production facilities by 2016 with an interim goal to reduce flaring by half (50 per cent) by 2011.
37. Establish policies and measures to reduce air emissions in coordination with the Ministry of Environment.
38. Best coalbed gas practices in North America. Companies will not be allowed to surface discharge produced water. Any re-injected produced water must be injected well below any domestic water aquifer.
39. Enhance the Oil and Gas Environmental Stewardship Program, ensuring sound environmental, land and resource management.
40. Continue to work to lift the federal moratorium on offshore exploration and development and reiterate the intention to simultaneously lift the provincial moratorium.
41. Work with the federal government to ensure that offshore oil and gas resources are developed in a scientifically sound and environmentally responsible way.
42. Participate in marine and environmental planning to effectively manage marine areas and offshore oil and gas basins.
43. Develop and implement a comprehensive community engagement program to establish a framework for a benefits sharing agreement resulting from offshore oil and gas development for communities, including First Nations.
44. Pursue regulatory and fiscal competitiveness in support of being among the most competitive oil and gas jurisdictions in North America.
45. Enhance infrastructure to support the development of oil and gas in British Columbia and address impediments to economic development such as transportation and labour shortages.
46. Encourage the development of conventional and unconventional resources.
47. Support the growth of British Columbia's oil and gas service sector.
48. Promote exploration and development of the Interior basins with a priority focus on the Nechako Basin.
49. Encourage the development of new technologies.
50. Add value to British Columbia's oil and gas industry by assessing and promoting the development of additional gas processing facilities in the province.
51. Provide information about local oil and gas activities to local governments, education and health service providers to inform and support the development of necessary social infrastructure.
52. Work with First Nations to identify opportunities to participate in and benefit from oil and gas development.
53. Support First Nations in providing cross-cultural training to agencies and industry.
54. Improve working relationships among industry and local communities and landowners by clarifying and simplifying processes, enhancing dispute resolution methods, and offering more support and information.
55. Examine oil and gas tenure policies and develop guidelines to determine areas that require special consideration prior to tenure approval.

Energy in Action

POWERSMART
BC Hydro offers a variety of incentives to adopt energy saving technologies. Incentives such as rebates on efficient lighting or windows encourages British Columbians to improve the energy efficiency of their homes and businesses.

PROVINCIAL SALES TAX EXEMPTIONS
Tax breaks are offered for a wide variety of energy efficient items, making it easier to conserve energy. Tax concessions are in place for alternative fuel and hybrid vehicles as well as some alternative fuels. Bicycles and some bicycle parts are exempt from provincial sales tax, as are a variety of materials, such as Energy Star® qualified windows, that can make homes more energy efficient.

NET METERING
The Net Metering program offered by BC Hydro for customers with small generating facilities, allows customers to lower their environmental impact and take responsibility for their own power production. The customer is only billed for their "net consumption": the total amount of electricity used minus the total produced. Net Metering helps to move the province towards electricity self sufficiency and expands clean electricity generation.

POWERING THE ECONOMY
The Oil and Gas sector invested $4.6 billion in B.C. in 2005 and contributed more to the provincial treasury than any other resource in 2005/06. In 2006 1,416 oil and gas wells were drilled in the province and between 2002 and 2005, summer drilling increased 242 per cent.

FRIDGE BUY-BACK PROGRAM
This program offers customers $30 in cash and no-cost pickup and disposal of an old, inefficient second fridge. If all second operating fridges in B.C. were recycled, we would save enough energy to power all the homes in the city of Chilliwack for an entire year.

LIGHTING REBATES
This program offers instant rebate coupons for the retail purchase of Energy Star® light fixtures and Energy Star® CFLs (Compact Fluorescent Lights).

WINDOWS REBATE
The Windows Rebate Program offers rebates for the installation of Energy Star® windows in new, renovated or upgraded single-family homes, duplexes, townhouses or apartments.

PRODUCT INCENTIVE PROGRAM
The Product Incentive Program provides financial incentives to organizations which replace inefficient products with energy efficient technologies or add on products to existing systems to make them more efficient.

HIGH-PERFORMANCE BUILDING PROGRAM FOR LARGE COMMERCIAL BUILDINGS
Financial incentives, resources, and technical assistance are available to help qualified projects identify energy saving strategies early in the design process; evaluate alternative design options and make a business case for the high-performance design; and, offset the incremental costs, if any, of the energy-efficient measures in the high-performance design.

HIGH-PERFORMANCE BUILDING PROGRAM FOR SMALL TO MEDIUM COMMERCIAL BUILDINGS
Incentives and tools are offered to help owners and their design teams create and install more effective and energy-efficient lighting in new commercial development projects.

NEW HOME PROGRAM
Builders and developers are encouraged to build energy efficient homes by offering financial incentives and Power Smart branding for homes that achieve energy efficient ratings.

ANALYZE MY HOME
BC Hydro offers an online tool that provides a free, personalized breakdown of a customer's home energy use and recommendations on where improvements can be made to lower consumption.

CONSERVATION RESEARCH INITIATIVE
A 12-month study in six communities that examines how adjusting the price of electricity at different times of day influences energy use by residential customers, and how individual British Columbians can make a difference in conserving power in their homes and help meet the growing demand for electricity in B.C.

THE GREEN BUILDINGS PROGRAM
Provides tools and resources to support school districts, universities, colleges, and health authorities to improve the energy efficiency of their buildings across the province.

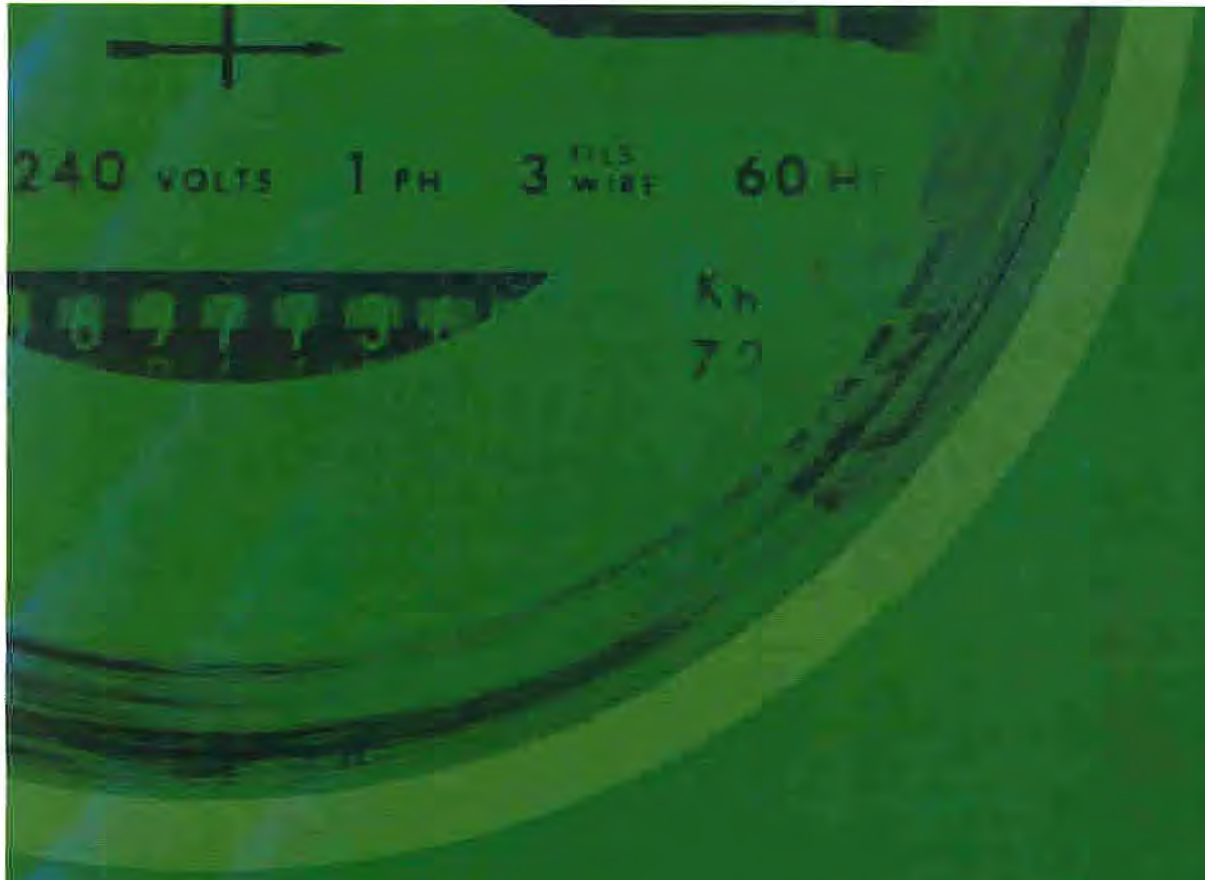
ATTRACTING WORKERS
The Ministry of Energy, Mines and Petroleum Resources hosts job fairs across B.C. to attract workers to the highly lucrative oil and gas sector. Job fairs were held in 14 communities in 2005 and 16 communities in 2006 attracting thousands of people and resulting in hundreds of job offers. Centre of Excellence Government is partnering with industry and the Northern Lights College in Fort St. John to build a centre for oil and gas excellence, more than doubling the number of students training for jobs in the oil and gas industry.

CENTRE OF EXCELLENCE
Government is partnering with industry and the Northern Lights College in Fort St. John to build a centre for oil and gas excellence, more than doubling the number of students training for jobs in the oil and gas industry.

100,000 SOLAR ROOFS FOR B.C.
The Ministers of Environment, and Energy, Mines and Petroleum Resources are sponsoring the development of a plan that will see the aggressive adoption of solar technology in B.C. The goal of the project is to see the installation of solar roofs and walls for hot water heating and photovoltaic electricity generation on 100,000 buildings around B.C.

PARTNERING FOR SUCCESS
Since 2003, the Province of B.C. has partnered in the construction of $158 million in new oil and gas road and pipeline infrastructure. The Sierra Yoyo Desan Road public private partnership improved the road allowing year round drilling activity in the Greater Sierra natural gas play. The project was recognized with the Gold Award for Innovation and Excellence from the Canadian Council for Public Private Partnerships in 2004.

ENERGY EFFICIENT BUILDINGS: A PLAN FOR BC
This strategy will lower energy costs for new and existing buildings by $127 million in 2010 and $474 million in 2020, and reduce greenhouse gas emissions by 2.3 million tonnes in 2020. The Province is implementing ten policy and market measures in partnership with the building industry, energy consumer groups, utilities, non-governmental organizations, and the federal government.



For more information on
The BC Energy Plan:
A Vision for Clean Energy Leadership, contact:

Ministry of Energy, Mines and Petroleum Resources
1810 Blanshard Street
PO Box 9318 Stn Prov Govt
Victoria, BC V8W 9N3

250.952.0241

www.energyplan.gov.bc.ca

BRITISH COLUMBIA
The Best Place on Earth

Ministry of
Energy, Mines and
Petroleum Resources

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Energy Resources Planning Study Executive Report

March 20, 2008

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Executive Summary

The environment is cited by Canadians as the most important problem facing Canada today.

Energy supply issues and conservation have not been as prominent. Canadians tend to link the environment to energy and rate energy sources based on perceptions of impact on the environment.

In the FortisBC service region, the need to conserve or reduce consumption and the cost of electricity were cited as the two of the most important issues facing the region.

Respondents have low awareness of the potential problems with future electrical supply. Just six in ten respondents were aware that the current supply of electricity is inadequate to meet demand over the next twenty years.

When asked about different electrical supply options, no single option emerged as the ideal solution that customers preferred. Of all electricity generation options presented to in the study, wind power was favoured by residential and commercial telephone survey respondents. The majority of these customers considered that wind power has a small impact on the environment. Large hydro (capacity and energy) was the highest-rated option for workshop participants, as they believed it to be a clean source of energy with a low impact on the environment.

The second-highest rating portfolio in the workshop featured natural gas with small hydro. Natural gas was the second-lowest ranked option by telephone survey respondents. This suggests that the workshop presentation and discussion encouraged the consideration of natural gas generation options.

Purchasing electricity from the wholesale energy market was the least-preferred option in both the telephone surveys and the workshops. This is consistent with the ranking of 'generating power in BC rather than importing it' as the most critically important consideration for telephone survey respondents.

Concerns about environmental impact were raised with all options.

Executive Summary

'Generating power within B.C. rather than importing it from other jurisdictions' and 'minimizing the impacts of power generation' were the top two 'critically important' considerations among telephone survey respondents. Workshop participants indicated that ensuring a reliable source of power was also critically important to them.

Respondents made different choices depending on their level of knowledge about the electrical supply options. Workshop participants, who were provided with information about the different options, showed a slight preference for hydro (capacity and energy). Telephone respondents, who were given no information about the options, preferred wind power.

It appears that the options preferred by the workshop participants were different to the telephone survey because of the understanding they gained from considering and discussing the information in the workshop. Many workshop participants indicated that they could understand the complexity of the challenge facing FortisBC. They also expressed a desire to see a wider exploration of the options.

Two-thirds of residential survey respondents who said that the generation of power had created environmental damage in the region or in their community thought that the level of damage was 'fully or somewhat acceptable'.

Over 90% of customers said that energy conservation would play a major or moderate role in ensuring a supply of power for the region. Compared to customers in the West Kootenay region, Okanagan customers were significantly more likely to mention the need to conserve or reduce energy consumption. Over 90% of customers said that individual consumers such as themselves can definitely or likely make an important contribution to reducing the overall energy use.

Two-thirds of residential and commercial customers stated that they would 'definitely or likely pay' more for electricity if it was required for new generation. 75% of customers would be willing to pay at least 5% more for new generation. West Kootenay customers have the most significant concerns about price.

Executive Summary

Prior to the survey, most customers had low levels of knowledge of the electrical supply plan announced by FortisBC. Between 30% and 40% of those who had heard something about the plan did not know any details.

Three-quarters of survey respondents said they were interested in learning more about the electricity supply plan. Environmental implications and cost implications were cited as the top two areas of interest.

The workshop format was a successful method of gaining community involvement. Many workshop participants were complimentary of FortisBC's efforts to involve them in decision making and found it an educational experience.

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Project Overview

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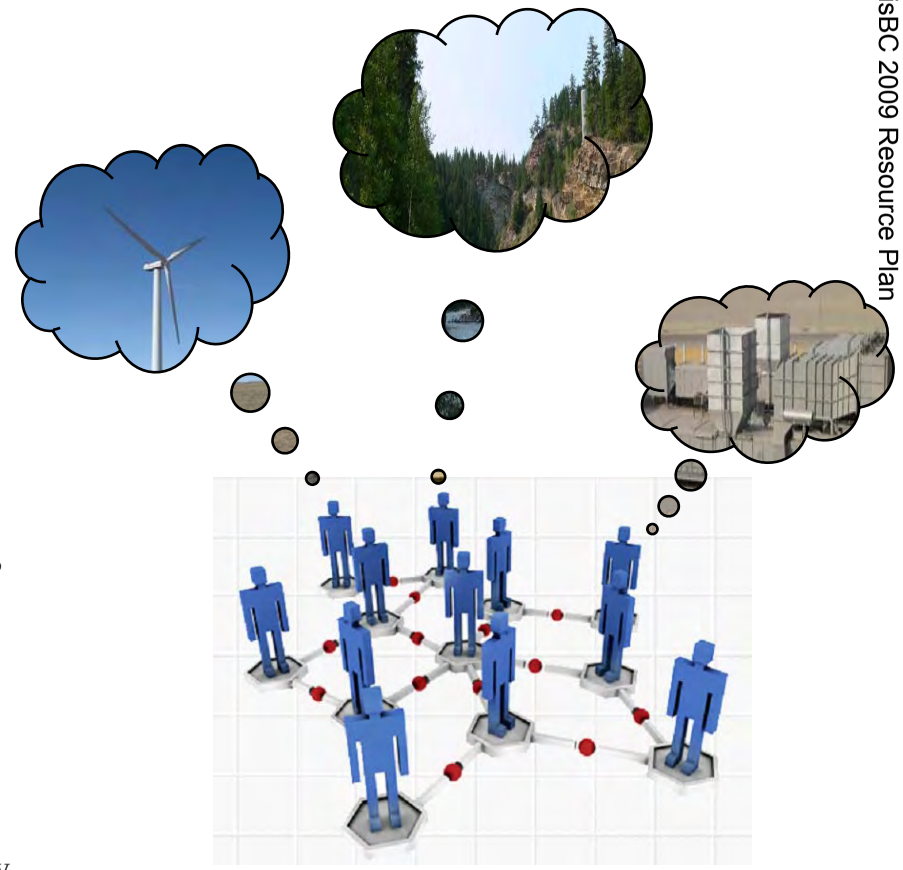
Objectives

FortisBC is currently developing its 2008 Resource Plan. In order to make well informed decisions over the course of the 2008 to 2027 planning horizon, the specific objectives of the 2008 Resource Plan are to research and analyze:

- The context within which FortisBC operates,
- Its load and peak demand forecast,
- Current resource capability, and
- The potential resource options available to close any forecast gap.

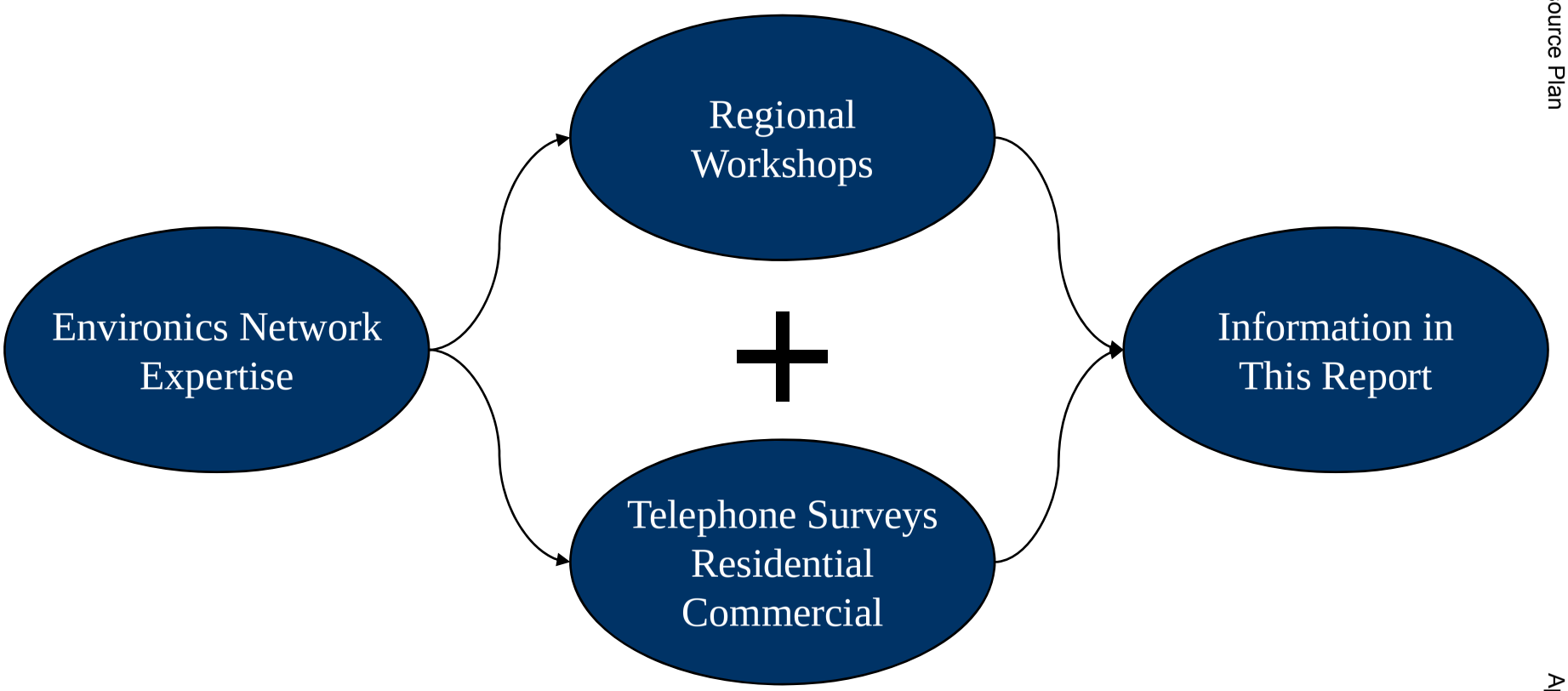
The purpose of this research study was to actively engage with FortisBC's customers, so that customer viewpoints could be incorporated into the Resource Plan. Two key goals of this research study were:

1. To hear the voice of the 'silent majority' – customers who will be affected by the implementation of FortisBC's Resource Plan but who might not participate in traditional community consultation events
2. Understand customers' opinions regarding future electricity preferences including environmentally friendly alternatives



Overview of Approach

The approach included both a qualitative/quantitative workshop technique and quantitative methodology to gain deeper insights and create wider dialogue with FortisBC's customers. Environics has also tapped into industry expertise within the Environics network to augment the findings from this study.



Regional Workshops

Hybrid Qualitative/Quantitative Methodology

Methodology

- A random sample of FortisBC customers living within 30 kilometers of Kelowna and Castlegar was contacted. Respondents were invited to attend based on meeting criteria for:
  - age
  - gender
  - industry occupation
  - responsibility for electricity bills, and
  - comfort with participating in a discussion setting.
- One workshops was held in Kelowna on February 18, 2008 and one was held in Castlegar on February 20, 2008.
- Participants were not advised in advance what the workshop would be about.
- In the workshop, FortisBC gave a 30-minute presentation on electricity generation and transmission options. A question and answer session followed the presentation. The Part A survey was completed prior to the presentation, and the Part B survey was completed following the presentation.
- 36 participants attended the Kelowna workshop and 49 participants attended the Castlegar workshop.
- Participants received a $75 cash honorarium for attending.

Methodological Limitations

Qualitative techniques such as workshops are valuable in marketing research as a means of developing a range of ideas and insights that can inform and fuel corporate discussions and, ultimately, decision-making.

Due to the small sizes of the workshops and inherent biases, the information gleaned from the workshop surveys cannot be projected to the entire market. More precise analyses of the market has been provided by the quantitative research undertaken with the telephone surveys.

Care must be taken in interpreting the survey data derived from the workshops as the sample variance is larger than the variance from the telephone surveys, due to the smaller sample size.

In order to compare results across the different forms, a set of “common” questions was used on both the telephone and workshop surveys. These “common” questions were included in Part A of the workshop questionnaire. Data cannot be directly compared between the telephone surveys and the Part B questionnaire due to the different understanding of workshop participants after FortisBC’s presentation.

The Workshop Process

Workshops were conducted with FortisBC customers in Kelowna and Castlegar to provide a forum for community debate and discussion around the different electricity options FortisBC is considering. Workshop participants were randomly recruited from the list of FortisBC customers in each area and were not advised in advance what the workshop would be about.

After a brief introduction, workshop participants completed Part A of a questionnaire. They completed Part B of the questionnaire after a presentation by FortisBC and 20-minute question and answer session.

Part A Questionnaire

- Time allowed: 15 minutes
- Captured demographic information on age, gender, postal code, employment status, own or rent home, type of dwelling, number of residents in dwelling
- Most important issue in the region
- What is the main sources or means by which electricity is generated today in the region
- Environmental damage by electricity source type (oil, natural gas, hydro-electric, etc)
- Perception of enough power for short term (2 to 5 years) and long term (20 years from now)
- Price perceptions of current electricity service
- What criteria are considered critically important in deciding which electricity supply options should be selected

Part B Questionnaire

- Time allowed: 15 minutes
- Identification of which of 8 electricity generation portfolios should be considered
- Rating perceived environmental impact for each of the 8 electricity generation portfolios
- Personal importance of BC Energy Plan goals
- Willingness to pay a higher price for new sources of electric power
- Role of energy conservation and willingness to reduce overall energy use
- Rating each of the 8 electricity generation portfolios against criteria
- Ranking each of the 8 electricity generation portfolios against expected transmission impact
- Which one of the 8 electricity generation portfolios is the respondent's most preferred option, and why

Key questions in the Part A and Part B questionnaires were consistent with the residential telephone survey, to enable comparisons between surveyed groups. Changes in response patterns between the telephone survey and Part B of the workshop survey identify the impact of closer engagement and discussion about the topic.

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Quantitative Methodology

Survey Method

- A telephone survey was administered to a random selection of FortisBC customers. The survey took an average of 20 minutes to complete.
- The residential survey was in field from February 8 – 23, 2008 and the commercial survey was in field from February 9 - 15, 2008.

Sampling

- A random sample of customers drawn from the FortisBC customer lists.
- For the residential survey, quotas were set by region based on customer proportions in each of the regions.
- Separate survey instruments were used for the residential and commercial customers. These questionnaires contained a large number of common questions and have been analyzed concurrently.
- The number of surveys completed by region and customer type was:

	Residential		Commercial	
	Quota	Actual	Quotas	Actual
Okanagan	480	480	No Regional Quotas	82
West Kootenay	320	323		119
Total	**800**	**803**	**200**	**201**

Telephone Interviewing and Quality Control

Field supervisors were present at all times to ensure accurate interviewing and recording or responses. A minimum of 10 percent of each interviewer's work was monitored for quality control in accordance with the standards set by the Marketing Research Industry Organisation (MRIA), of which Environics is a member.

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How to Read This Report

In reading this report, the reader is advised of the following:

- Given the varying sample sizes and differences in methodologies, caution is urged in comparing any results between Residential, Commercial and Workshop surveys.
- Quotas were not set for regions; however, the distribution of completes by region closely matches that of the Canadian population (based on Statistics Canada data).

SIGNIFICANCE TESTING

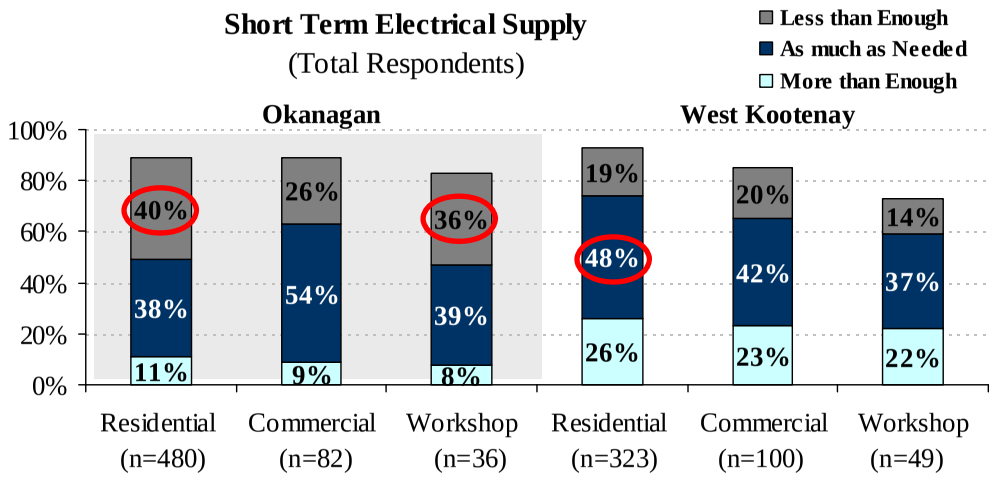
The margin of error for a sample size of 803 is plus or minus 3.5%, 19 times in 20. This margin increases for respondent subgroups. The following table indicates the relative margins of error for smaller sample sizes.

Sample Size	Margin of Error
1800	+/- 2.3%
800	+/- 3.5%
700	+/- 3.7%
400	+/- 4.9%
300	+/- 5.7%
200	+/- 6.9%
100	+/- 9.8%
50	+/- 13.9%

Where results are significantly different, they are circled with a solid line. Where results are notably different, but not statistically different, they are circled with a dotted line. Significance is tested between Residential, Commercial and Workshop participants where possible.

Significantly higher

Notably different



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Canadians, The Environment and Energy in Context

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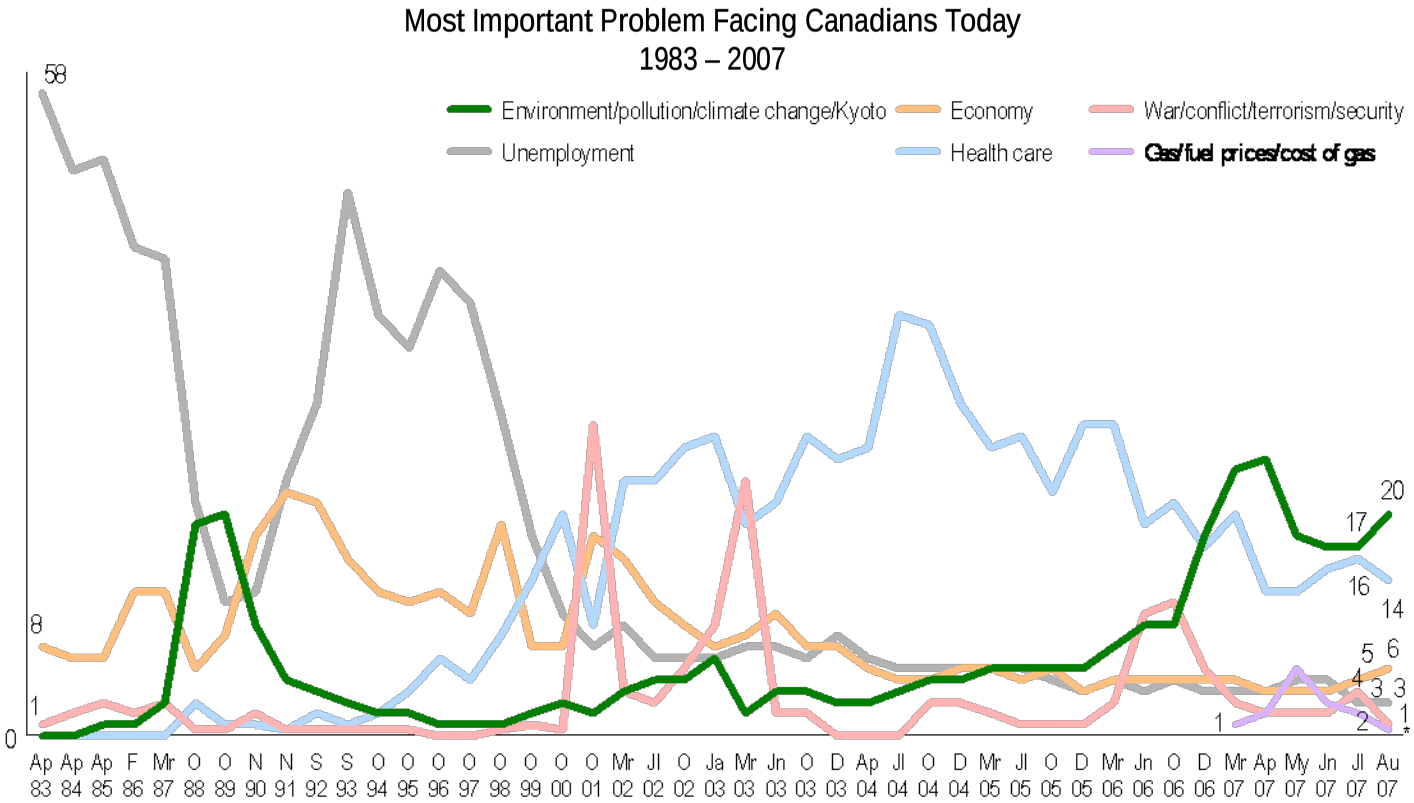
Canadians are generally aware that energy supply is not sufficient to meet demand over time but have little concern about potential short term energy shortages.

- Canada has seen rapid growth in public concern about the environment.
- Energy supply issues and conservation have not been as prominent for Canadians, with price typically being the most pressing issue.
- British Columbia's population has the highest awareness and concern about the environment.
  - The need to conserve and reduce energy consumption and cost of electricity were the two most important issues mentioned with respect to the generation and use of electrical energy in this study.
- B.C. respondents have low awareness that there are potential problems with electrical supply over the next two to five years.
- Just six in ten B.C. respondents are aware the current supply of electricity is inadequate to meet demand over the next twenty years.
  - Okanagan residents are more likely to say long-term electrical supply is a problem facing the region.
  - West Kootenay residents are much less likely to believe that long-term electricity supply is an issue for the region.

Canadians and the Environment

Canada has seen rapid growth in public concern about the environment.

- Although concern with the environment is primarily driven by climate change, Canadians are just as concerned about other environmental issues such as air pollution and water quality.
- Environment is most salient as a "national" issue and less so at the provincial or regional level where issues such as health care and unemployment emerge as more prominent issues.



Source: Environics Research - Focus Canada and Canadian Environmental Barometer, 1983-2007

Canadians and Energy

Energy supply issues and conservation have not been as prominent for Canadians, with price typically being the most pressing issue.

- Canadians link the environment to energy and tend to rate energy sources based on perceptions of impact on the environment.
  - Hydro-electric power is widely considered to be the most environmentally friendly of traditional energy sources, while coal and nuclear energy are seen as most harmful.
  - There is limited awareness and understanding of natural gas as a source of energy.
  - Renewable sources (wind, solar, biomass) are widely seen as highly desirable, as they have little or no environmental impact, but they are not well understood.

- Energy supply has historically not been a major issue of concern for Canadians.
  - Although there is a general awareness among Canadians that energy supply is not sufficient to meet demand over time, overall there is limited concern about short term problems associated with an energy shortage.

- Issues related to energy vary across provinces in Canada.

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The British Columbia Context

Provincially, British Columbia's population is among the most aware and concerned with the environment; concern tends to be higher in Vancouver compared to the interior.

- The B.C. government is taking a leadership role in taking action on climate change.
- 55% of B.C. respondents cite support for new ground breaking carbon tax (*refer to chart).

Do you support or oppose the new carbon tax for B.C.?[1]

	British Columbia %	Vancouver CMA[2] %	Rest of Province %
NET SUPPORT	**55**	56	55
Strongly support	**15**	15	16
Somewhat support	**40**	41	39
Somewhat oppose	**15**	20	10
Strongly oppose	**27**	22	31
NET OPPOSE	**42**	42	41
Depends/No opinion	**3**	1	3

[1]Specific question wording is presented below [2]Census Metropolitan Area (Statistics Canada)

The B.C. Energy Plan

- In February 2007, the B.C. government issued the "B.C. Energy Plan: A vision for clean energy leadership". The Energy Plan outlines conservation, energy efficiency, and clean energy goals to make the province energy self-sufficient by 2016.
- The Energy Plan specifically addressed the issue that B.C. is now dependent on other jurisdictions for up to 10 per cent of its electricity supply and that B.C. Hydro estimates demand for electricity to grow by up to 45 per cent over the next 20 years.

*Reference: Canadian Environmental Barometer Survey conducted by Environics Research

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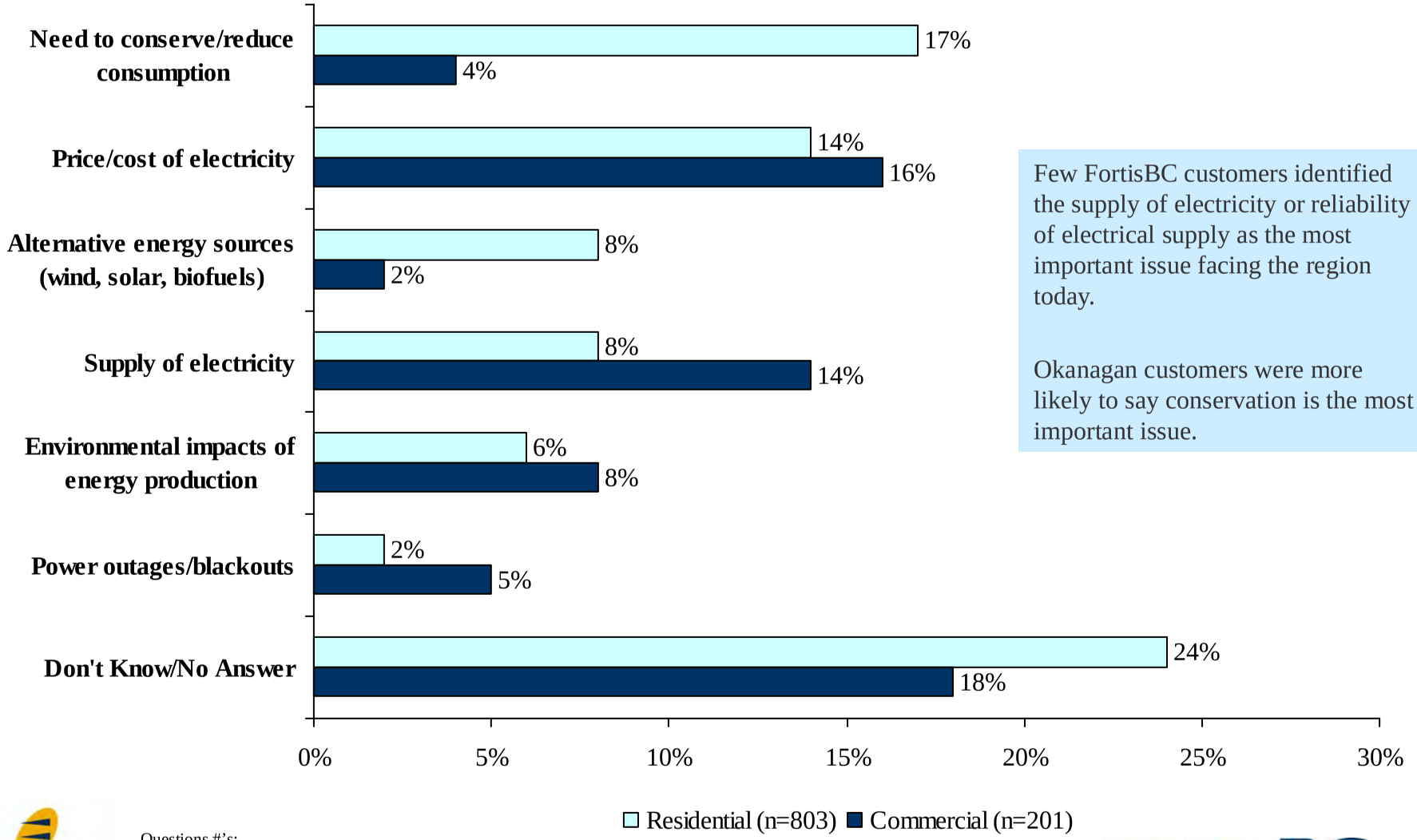
Most Important Issue for Region regarding Electricity

The need to conserve and reduce energy consumption and cost of electricity were cited as two of the most important issues facing the South Central region by telephone survey respondents.



Few FortisBC customers identified the supply of electricity or reliability of electrical supply as the most important issue facing the region today.

Okanagan customers were more likely to say conservation is the most important issue.

Questions #'s:
Residential Survey Q.2
Commercial Survey Q.2

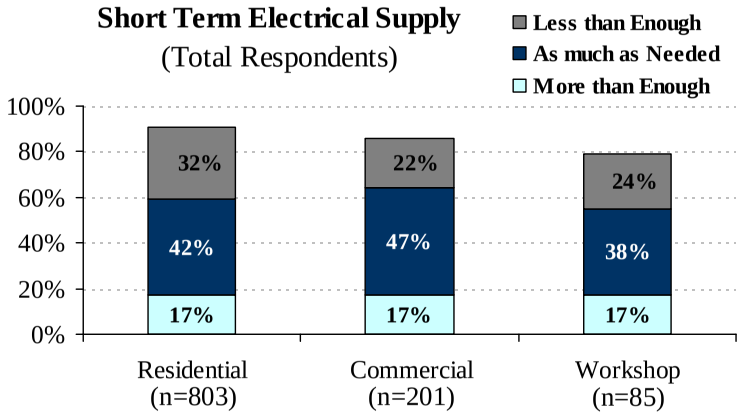
Awareness of Short Term Electrical Supply Problems

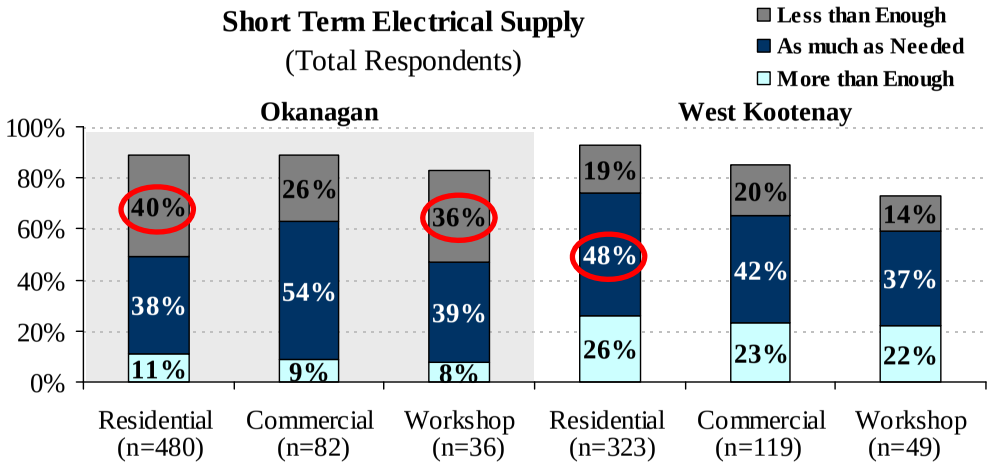
Respondents have low awareness that there are potential problems with electrical supply over the next two to five years.

Less than one-third of respondents are aware of potential electrical supply problems in the short term.

Okanagan respondents are more likely to say the supply of electrical power for the region was less than enough over the next two to five years.

West Kootenay residential respondents are more likely to say the supply of electrical power is as much as is needed for the next two to five years.





Questions #'s:
Residential Survey Q.7
Commercial Survey Q.7
Workshop Part 1: Q.11

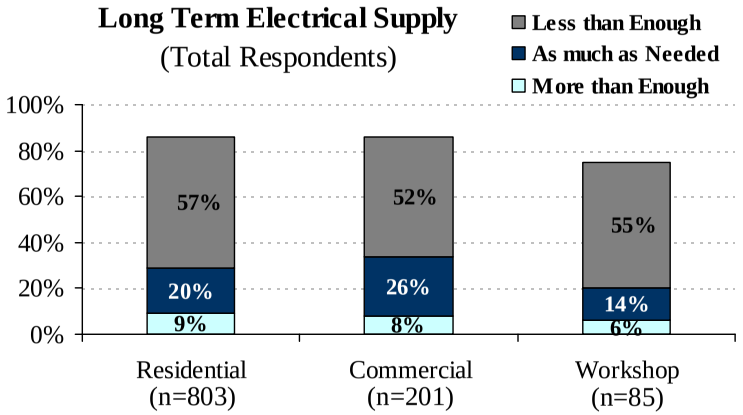
Awareness of Long Term Electrical Supply Problems

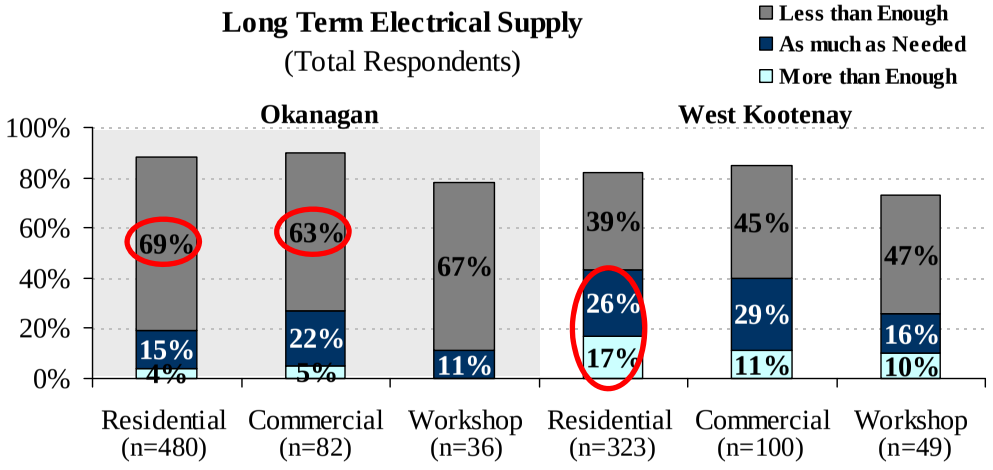
Just six in ten respondents are aware the current supply of electricity is inadequate to meet demand over the next twenty years.

Over half of respondents are aware of electrical supply problems expected in the long term.

Okanagan residential and commercial respondents are more likely to say the supply of electrical power for the region is less than enough for the next twenty years.

On the flip side, West Kootenay residential respondents are more likely to say the supply of electrical power is more than enough or as much as is needed for the next twenty years.





Indicates a statistically significant difference between the Okanagan and West Kootenay Region

Questions #'s:
Residential Survey Q..8
Commercial Survey Q.8
Workshop Part 1: Q.12

The Customer Voice - Electrical Supply Options

In contrast to the telephone survey respondents, workshop participants ranked the 'large hydro – capacity and energy' as their top preferred option, followed by gas and small hydro portfolio. Telephone respondents indicated a strong preference for 'green' options such as wind power.

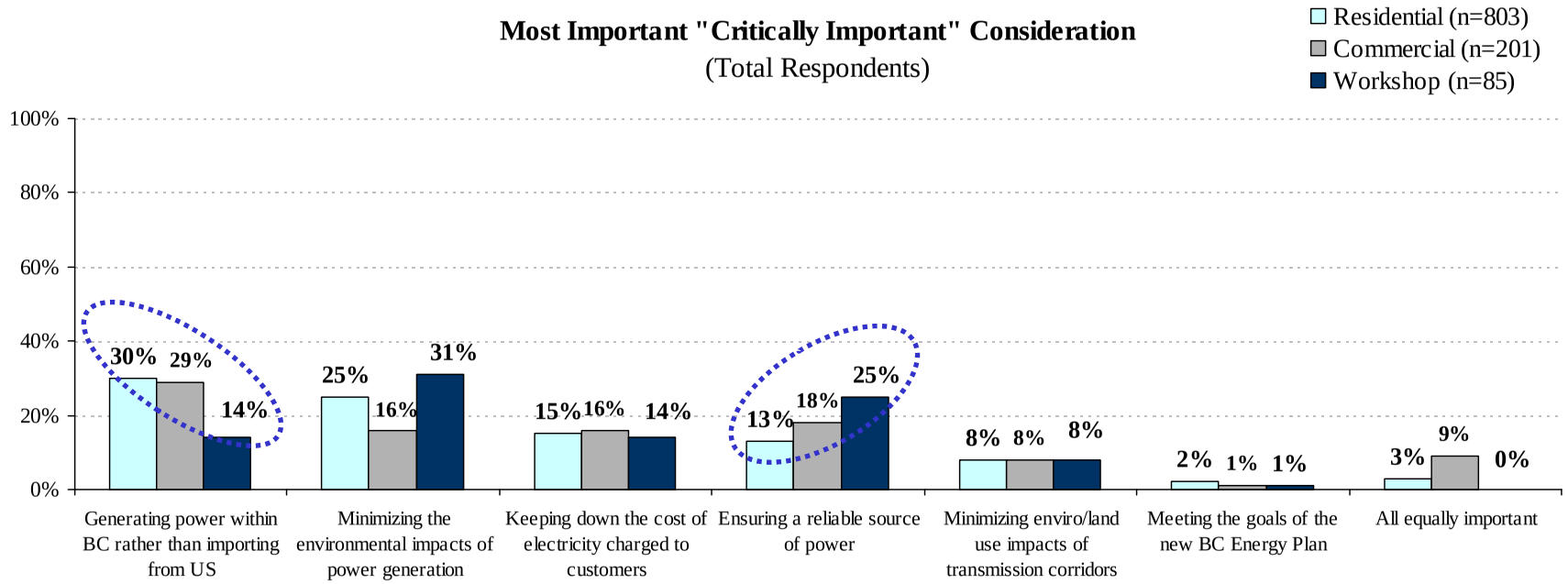
- The workshops held in Kelowna and Castlegar provided an opportunity to engage with residents who might not participate in traditional community consultation events.
- The difference in preference between electricity generation options between the workshops and the telephone surveys may be due to the greater engagement and discussion in the workshop compared to the survey. The telephone survey findings tended to reflect generally held beliefs (such as the positive environmental impact of wind power) while comments from workshop participants indicated that they often considered more of the factors from the FortisBC presentation and the question and answer session in making their decisions.
- Many workshop participants appreciated and valued the opportunity to have an input into FortisBC's decision making on electricity generation options.

Thoughts for Consideration

- People exposed to different information have different perspectives. This is evident when comparing results between the workshops and the telephone surveys.
- The demographic profile of workshop participants was different compared to the telephone survey respondents. In general, workshop participants were likely to be younger and there was a greater proportion from the West Kootenay area. This will influence their perspectives and what is important to them.
- Workshop participants rated 'reliability' as their top consideration, and this criteria will have influenced the choices they made.
- The difference in preference between electricity generation options between the workshops and the telephone surveys is likely to be due to the engagement in the workshop compared to the survey. Comments from workshop participants indicated that they considered the factors from the FortisBC presentation and the question and answer session in making their decisions.
- The information provided in the workshop appeared to increase the importance attached to some of the 'rational' factors around the choice of electricity generation: cost, reliability, and local generation. This resulted in some participants preferring portfolios which feature generation options that did not poll favourably in the telephone surveys, such as natural gas or large hydro.
- Workshop participants were also less likely to 'definitely' prefer options. It may be that one of the outcomes of the workshop process was a decrease in the degree of certainty about the benefits of one option over another.

Critically Important Considerations

Generating power within B.C. rather than importing it from the U.S. and minimizing the environmental impacts of power generation were the top two critically important considerations among telephone respondents. Workshop respondents indicated that ensuring a reliable source of power was also critically important to them.



Both workshop participants and residential telephone survey respondents saw 'minimising the environmental impacts of power generation' as amongst the most critically important considerations. 'Generating power within BC' was considered more important by telephone survey respondents compared to workshop participants, who saw 'ensuring a reliable source of power' as critical.

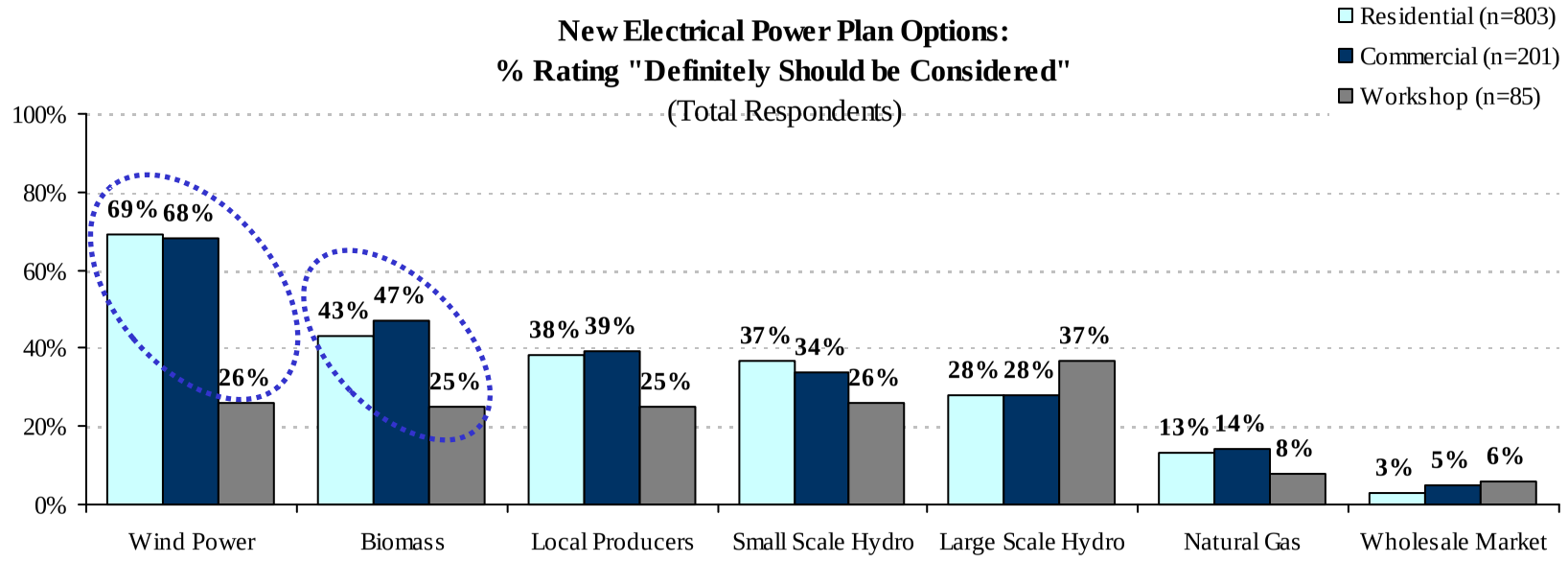
Workshop participants responded to this question before hearing the FortisBC presentation or the question and answer period.

Notably different

Questions #'s:
Residential Survey Q.18
Commercial Survey Q.18
Workshop Part 1: Q.16

The Electrical Supply Options

Respondents chose differently depending on their level of knowledge about the electrical supply options. Workshop respondents, who were provided with information about the different options, showed a slight preference for large hydro (capacity and energy), while telephone respondents who were given no information about the options, preferred wind power.



Workshop participants provided these 'consideration' ratings after listening to the FortisBC presentation and the question and answer session. As a result, workshop participants had a greater general knowledge about the options, the benefits and the disadvantages of each compared to the telephone survey respondents.

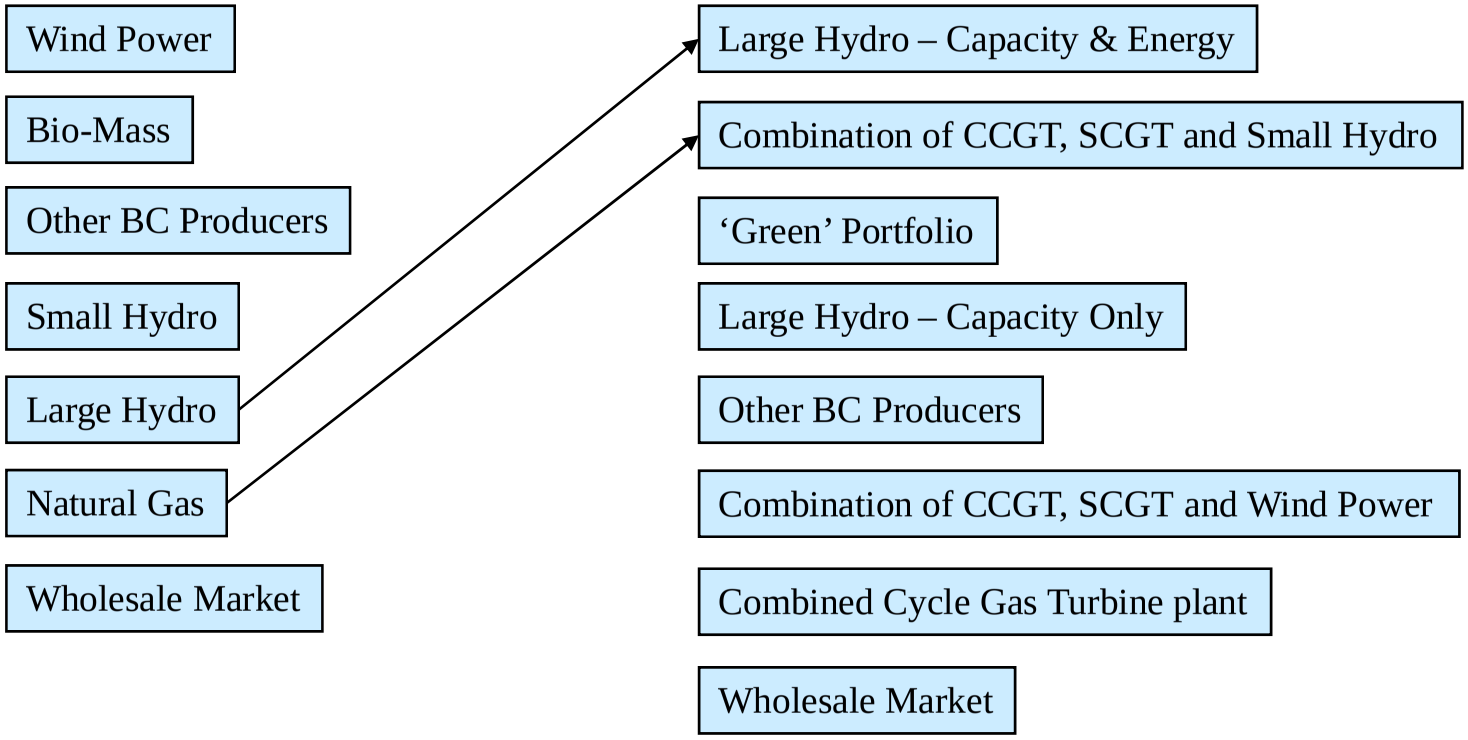
The lower scores for 'definitely should be considered' by workshop participants compared to the telephone survey respondents suggest that gaining more information about the options being considered reduced the degree of certainty about choosing one option over another. However, the combined 'definitely consider' and 'should consider' ratings were similar between the workshop participants and survey respondents, suggesting that 'more educated' workshop participants were 'hedging their bets'.

Questions #'s:
Residential Survey Q.19
Commercial Survey Q.19
Workshop Part 2: Q.1A

Notably different

The Impact of the Workshop

It appears that the options preferred by workshop participants are different to the telephone survey responses because of the understanding they gained from considering and discussing the information in the workshop.



Questions #'s:
Residential Survey Q.19
Workshop Part 2: Q.1A

Workshop Portfolio Assessments

The ratings assigned to each electrical supply option on how well it addresses important concerns as well as the participants' verbatim comments reflected that the FortisBC presentation was understood and considered during the evaluation process.

How Well Each Portfolio Addresses Concerns – Definitely/Likely Addresses This Concern

	Minimizing Environmental Impacts	Minimizing Land Use Impacts of Transmission	Keeping Down the Cost	Ensuring a Reliable Source	Generating Power Within BC
Buying more electricity from the wholesale energy market			✗		✗
Development of a Combined Cycle Gas Turbine plant	✗			✓	✓
Development of large hydro-electric dam - capacity only	✗	✗		✓	✓
"Green Portfolio"				✗	✓
Combination of Gas Turbine Plants and Wind Farm				✓	✓
Combination of Gas Turbine Plants and Small Hydro	✗			✓	✓
Buying electricity from other BC producers			✗		
Development of large hydro-electric dam - capacity & energy	✗	✗		✓	✓

Workshop participants saw that each portfolio had its pros and cons:

- Combined Cycle Gas Turbine option received the lowest ratings for 'minimizing environmental impact.'
- Both portfolios involving large hydro-electric dams received low marks for 'minimizing the impact of transmission.'
- Buying from the wholesale energy market or from other BC producers received low scores for 'keeping down the cost.'
- Reliability was seen as a weakness for the Green portfolio.

✗ 60% or fewer of participants rated as 'definitely' or 'likely' addresses concern

✓ 80% or more of participants rated as 'definitely' or 'likely' addresses concern

Questions #'s:
Workshop Part 2: Q.7

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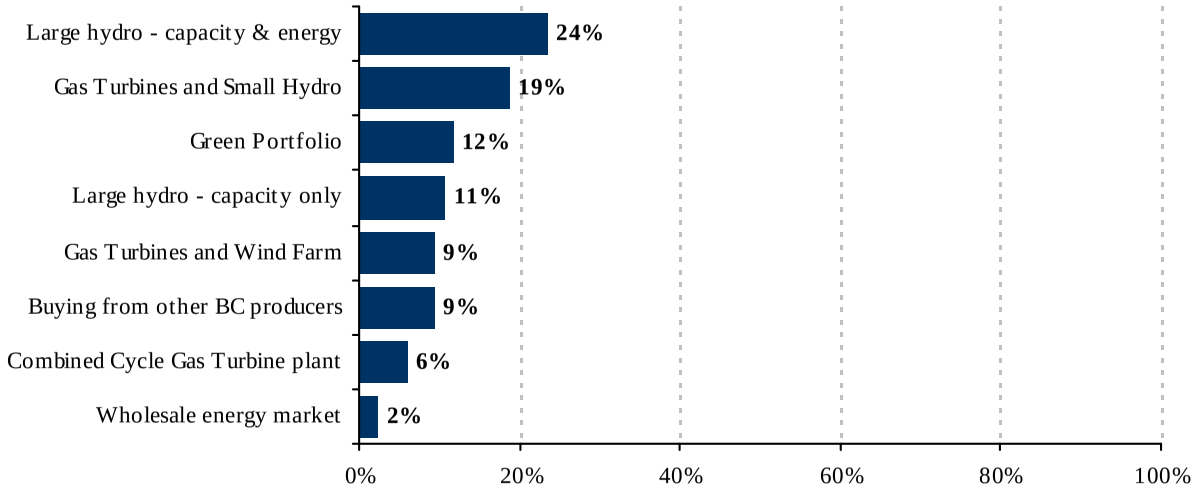
Workshop Portfolio Assessments, cont'd…

Large hydro (capacity and energy) was the preferred choice by a quarter of workshop participants with nearly half citing "less impact on the environment" as the reason for their choice.

Of All the Options Presented Tonight, Which ONE is Your Preferred Option?
(Total Respondents, n=85)



Regional variations were pronounced – just over 30% of Kelowna participants favoured the large hydro (capacity and energy) option compared to 18% of Castlegar participants.

Nearly one-quarter of women (21%) favoured the Green portfolio while one-third of men (34%) preferred the 'large hydro' option.

NOTE: 12% of Castlegar participants (6/49 attendees) did not respond to this question.

Why is This One Your Preferred Option?
(Total Respondents, n=85)

Less impact on environment	45%
This is reliable/makes sense long term	27%
Need to be self-sufficient, not dependent on others	18%
It is cost efficient, less for the consumer to pay	17%
Can profit from excess power generated, good for BC economy	7%

What Problems or Concerns, If Any, Do You Have With Your Preferred Option?
(Total Respondents, n=85)

Environmental impact	17%
Costs - general	14%
That supply will run out, it is not reliable	12%
Transmission line costs, impacts	11%
What to do with greenhouse gases, emissions	9%

Questions #'s:
Workshop Part 2: Q.9

Reasons Portfolio Preferred - Workshop

Comments from workshop participants who favoured large hydro suggested that they saw hydro as the 'tried and true' option: reliable and cost-effective over the long term. Participants who favoured options with natural gas saw these options as lower cost and having lower transmission impacts.

The reasons for choosing a particular option were justified by respondents on the basis of environment, cost, reliability, and availability of input resources.

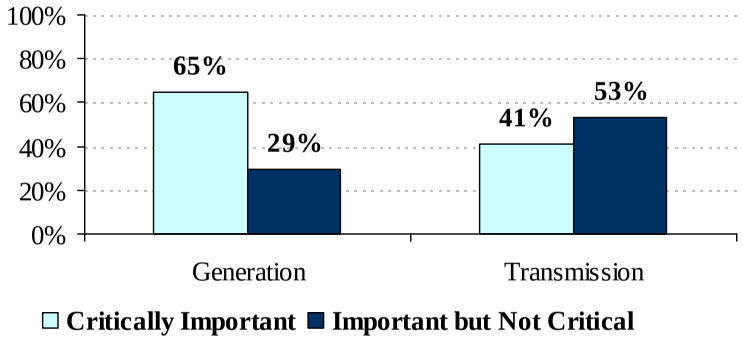
Ironically, positive environmental effects were cited by participants as justification for all types of electricity generation options, suggesting that 'environmentally friendly' does not have a fixed set of criteria but can be explained in multiple ways.

Large Hydro Capacity & Energy	**Gas & Small Hydro**	**Green Portfolio**
Ranked #1	Ranked #2	Ranked #3
"Overall long term sustainability"	*"Lowest environmental impact and probably lower cost impacts due to low transmission requirements."*	*"Least impact from each of these."*
"Low overall impact. Large impact in area of dam but better than several impacted areas.".		*"It is the most environmentally friendly and to me appealing because of that."*
"Most reliable in future as needs grow."	*"Seems the most logical, have plenty of waterways for which can supply dams, gas turbine for supplementing the small water way."*	*"I believe the technology will improve these facilities over the years."*
"Less impact to our area which is very environmentally sensitive."		*"Seems the least damaging and most cost effective."*
"Best long term option for environment, province and company".	*"It doesn't rely on just one potential resource and it uses some local options."*	

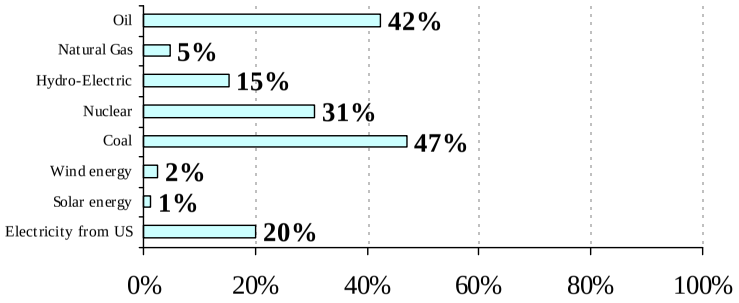
Transmission Considerations

When workshop participants were asked to consider the impact of transmission and rank the portfolios, the combined cycle gas turbine plant option was ranked the top preference.

Importance of Minimising Environmental Damage - Transmission vs. Generation
(Total Respondents)



Damage Caused in the Community by Electricity Generation Source - Major Impact
(Total Respondents)



Nearly two-thirds of workshop participants saw minimizing the environmental damage from electricity generation as 'critically important' while just over half thought that minimizing the damage from transmission was 'important but not critical'. The analysis of individual responses suggests that transmission impact was not a deciding factor in choosing the overall preference.

Solar, wind and natural gas were considered to have the lowest impact on the environment in the community.

NOTE: Over half of workshop participants did not answer the question which included transmission impact (Part 2: Q.8) correctly to or did not provide an answer.

Ranking of Preferred Options – Including Transmission and Overall

Ranking of Options Including Transmission Impact (n=41)	Overall Preferred Option (n=85)
Combined Cycle Gas Turbine Plant	Large Hydro - Capacity & Energy
Large Hydro – Capacity & Energy	Gas Turbines and Small Hydro
Green Portfolio	Green Portfolio
Gas Turbines and Small Hydro	Large Hydro – capacity only
Gas Turbines and Wind Farm	Gas Turbines and Wind Farm
Large Hydro – capacity only	Buying from other BC producers
Buying from other BC producers	Combined Cycle Gas Turbine Plant
Wholesale energy market	Wholesale energy market

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Questions #'s:
Workshop Part 1: Q.15 and Q.10
Workshop Part 2: Q.8 and Q.9

Workshop Comments

Many workshop participants provided additional comments that suggested that they could understand the complexity of the challenge facing FortisBC as well as indicating that they would like to see wider exploration of options.

"I believe that the large dams are the answer, but it's very important to look at other natural options for the future (solar and other)."

"Patience can pay big dividends. Buy power while exploring opportunities. Mean time, reduce consumption to reduce shortfalls."

"There are no easy answers! It is clear that as a for-profit company, you are endeavoring to make some decisions which will be at least palatable to your customers - a noble effort of consultation. Now I can't complain about costs as I have had a real chance to make my desires and concerns heard."

"What would be the cost of upgrading existing dams to produce more as compared to building more dams?"

"Coal gasification? Geothermal?"

"Utilize all of the hydro power possible without seriously impacting the environment."

"I think atomic energy will be the way of the future."

"A very difficult balancing act - long term solutions are not presented here, only the lesser of evils. More R&D necessary in areas of solar production necessary, so why not start now?"

"Large hydro dam projects should not exclude developing local green power generation and alternative energy initiatives. Conservation and efficiency should also remain as a prominent goal."

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Environment and Conservation

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Section Highlights: Environment and Conservation

Customers appear to accept that there will be environmental damage in return for electricity.

- Two-thirds of respondents did not perceive any environmental impacts from electricity generation in their community although half identified large impacts in the region.
- Among those who have noticed an environmental impact from electrical generation in their region or community, approximately two-thirds perceive the level of damage to be 'fully acceptable' or 'somewhat acceptable'.
- Large hydro was identified as having the greatest environmental impact, followed by natural gas.

Thoughts for Consideration

- Customers appear to accept some environmental damage in return for electricity. The challenge is to balance the type and amount of damage with the benefits the individual gains from having the electricity. Damage caused in an area outside the region or local community may be more acceptable to some customers.
- The relationship between low environmental damage and electricity generation type preference is not clear-cut. For example, 65% of residential customers thought bio-mass created major or moderate environmental damage, but it was still the second-most preferred option for generation.
- Fortis BC's customers are strongly supportive of conservation efforts. This is consistent with the Canadian Electricity Association's findings that 95% of Canadians are most in favour of energy efficiency programs to meet the future energy needs of their province[1].

[1] Canadian Electricity Association, 2007 Public Attitudes Research Project

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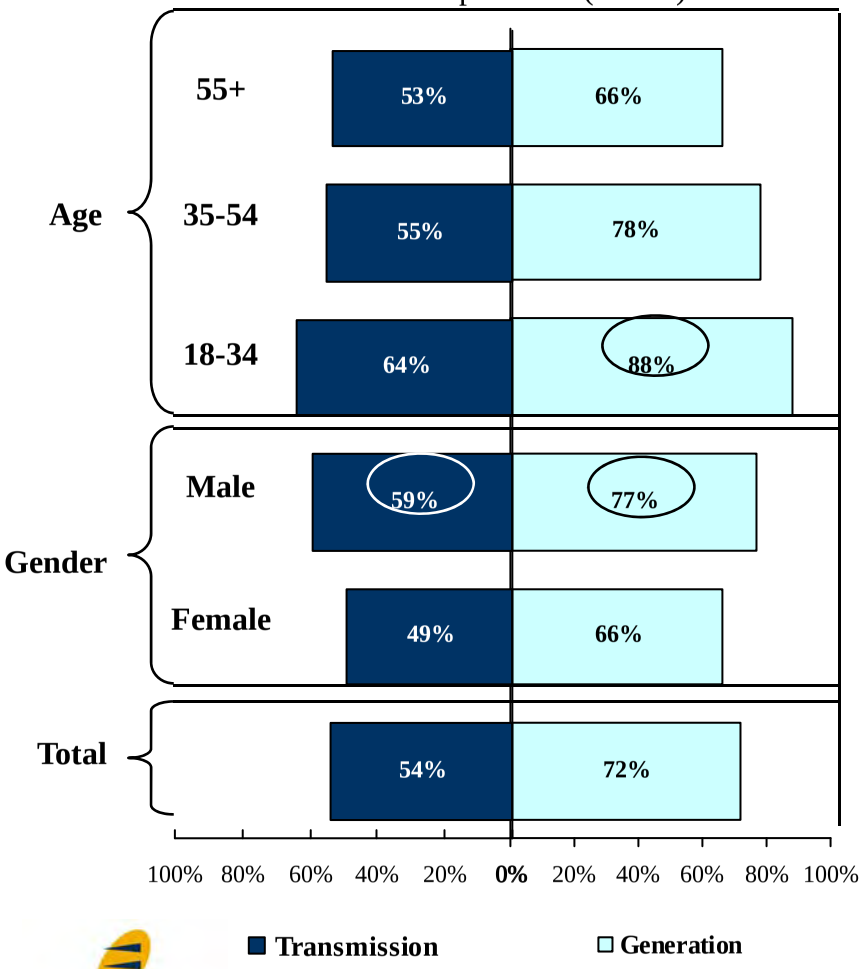
Role of Environment – Residential Telephone Survey

Among those who have noticed an environmental impact from electrical generation in their region or community, 67% perceive the level of damage to be 'fully acceptable' or 'somewhat acceptable'.

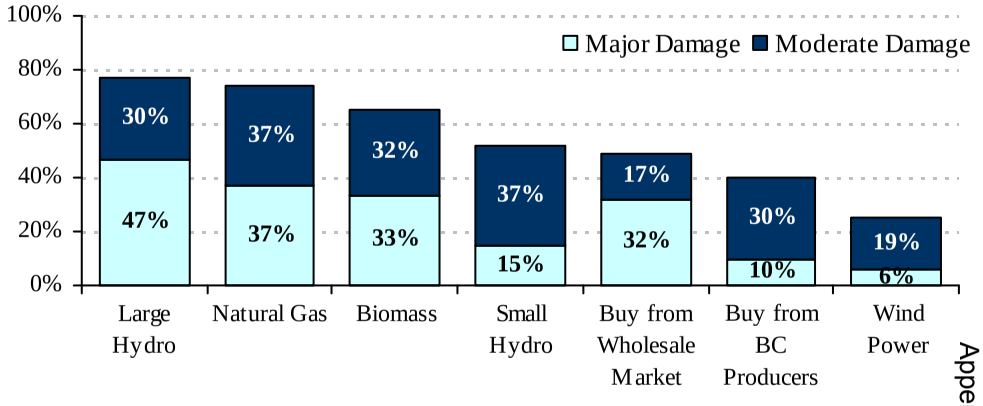
Who Rated 'Minimising Environmental Impacts' as Critically Important?
Total Respondents (n=803)



Perception of Damage Caused by Generation of Electric Power
Among Those Who Identified a Type of Generation In the Region (n=635)

	Large Impact	Small Impact
The South Central region of B.C.	51%	44%
The community where you live	28%	67%

Perception of Damage Caused by Electricity Generation Type
Total Respondents (n=803)

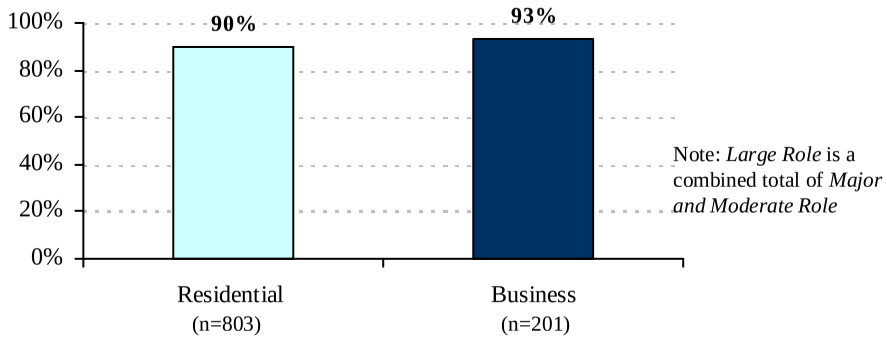


Questions #'s:
Residential Survey Q.17, Q.5 and Q.22

Role of Energy Conservation in Ensuring Supply of Power for the Region

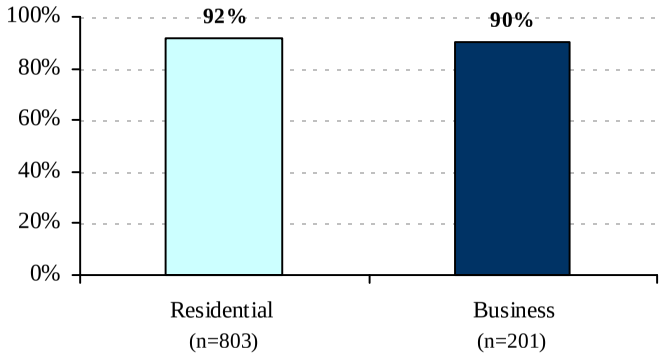
This study shows that the public is supportive of conservation efforts. Some workshop respondents suggested greater emphasis and incentives for conservation.

Energy Conservation Playing a Large Role
(Total Respondents)



Note: *Large Role* is a combined total of *Major and Moderate Role*

Contribution to Reducing Overall Amount of Electrical Energy Consumption
(Total Respondents)



Note: *Contribution* is a combined total of *Definitely and Likely*

A study conducted for the Ontario Power Authority in 2007[1] reported that 87% of Ontario residents surveyed said that individual consumers could definitely or likely make a difference in reducing energy use, which is similar to the level of FortisBC customer support.

The OPA study recommended providing a sense of what is a legitimate level of effort/results for a household to strive for. This would include establishing targets that go beyond 'turning off lights' and adjusting thermostats.

[1] Environics Research Group, "Ontario Consumer Market Research on Attitudes and Behaviour towards Electricity Conservation", April 2, 2007. Available: www.powerauthority.on.ca

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Questions #'s:
Residential Survey Q.24 and Q.25
Commercial Survey Q.24 and Q.25

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Role of Conservation

Over 90% of customers in the residential, commercial and workshop surveys agreed that individuals like themselves can make an important contribution to reducing overall energy use.

% of Respondents Stating Energy Conservation Can Play <u>Large</u> Role in Ensuring Supply of Power

	Residential	Commercial	Workshop
	(n=803)	(n=201)	(n=85)
Total	90%	93%	85%
Male	87%	91%	80%
Female	92%	95%	92%
Okanagan	89%	91%	97%
West Kootenay	90%	93%	76%

Residential telephone survey respondents who said that energy conservation would play a large role (90% of respondents):

- Saw the need to conserve or reduce energy consumption as the most important issue for the region with respect to the generation and use of electricity.
- Saw minimizing the environmental impacts of power generation and transmission as 'critically important'.
- Were more likely to 'definitely consider' or 'definitely not consider' electricity generation options based on perceived impact on the environment.

Questions #'s:
Residential Survey Q.24
Commercial Survey Q.24
Workshop Part 2: Q.5

The Importance of Price

Section Highlights: The Importance of Price

Price is typically the most pressing issue for Canadians when thinking about energy supply issues and conservation.

- Half of B.C. residential and commercial customers feel that the price they currently pay for electricity is too high.
- Concerns about price were more significant in the West Kootenay region.
- 75% of consumers would be 'definitely or likely' willing to pay more for new electricity generation. 30% of West Kootenay residents said they would not pay a higher price for new electricity generation, significantly more than in the Okanagan.

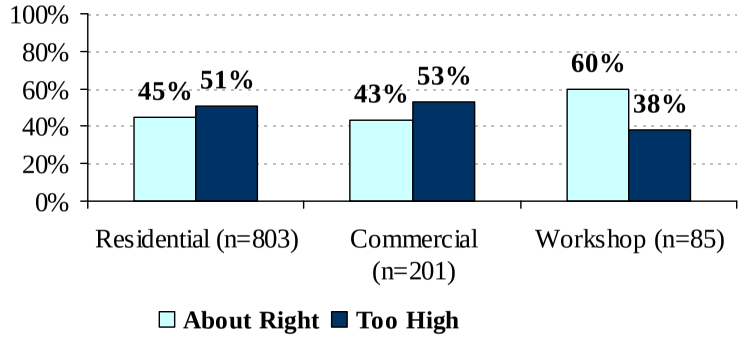
Thoughts for Consideration

- Concerns about price are common in surveys about electricity. For example, the January 2007 study conducted by Environics Research for the Ontario Power Authority found 51% of Ontario residents thought they paid too much for electricity – the same percentage as in the FortisBC territory.
- West Kootenay residents were more sensitive about price changes. Significantly more West Kootenay residents have household incomes between $40,000 and $60,000 compared to the Okanagan area.
- The price sensitivity questions asked in the survey referred to the types of electricity that the respondent preferred. Actual sensitivity may vary if the final option chosen is not the same as the option the customer preferred.

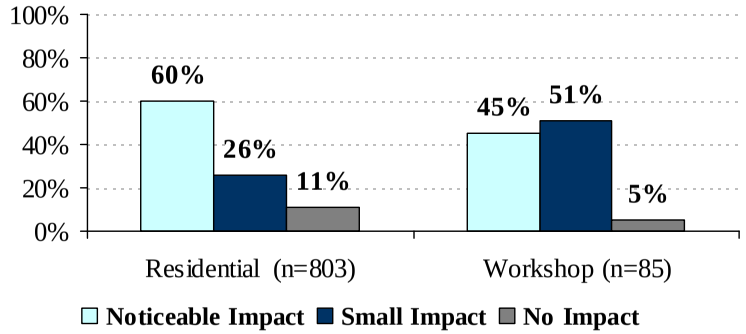
Current Pricing Perceptions

As expected, very few customers thought they paid too little for electricity. Over half of telephone respondents felt the price paid for electricity was too high.

% Feel the Price You Pay for Electricity is...
(Total Respondents)



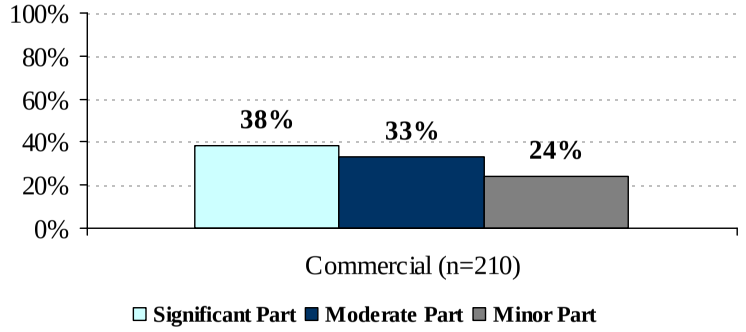
Does the Current State of Your Household Electric or Hydro Bill have a…
(Total Respondents)



Residential customers aged 35-54 tended to say that the current price is 'too high'.

A higher proportion of West Kootenay residents said that the size of their household electricity bill made a 'noticeable' impact on their finances each month and were more likely to say that current prices were too high.

Impact of Current Electric or Hydro Bill on Overall Operational Budget
(Total Respondents)

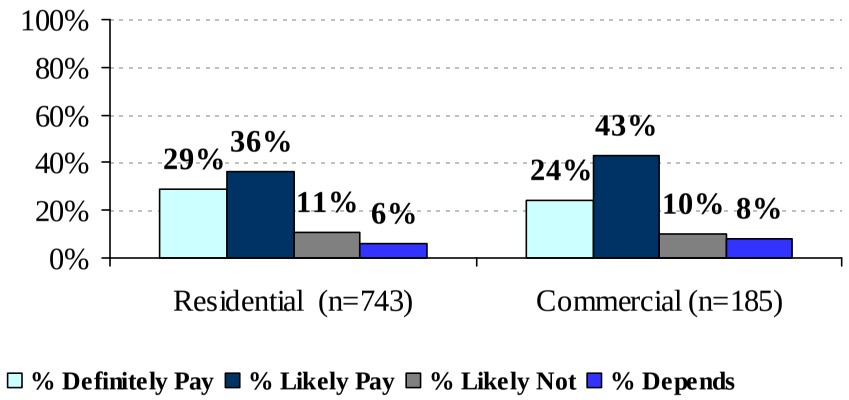


Questions #'s:
Residential Survey Q.10 and Q.11
Commercial Survey Q.10 and Q.11
Workshop Part 1: Q.13 and Q.14

Willingness to Pay More for Electricity Options

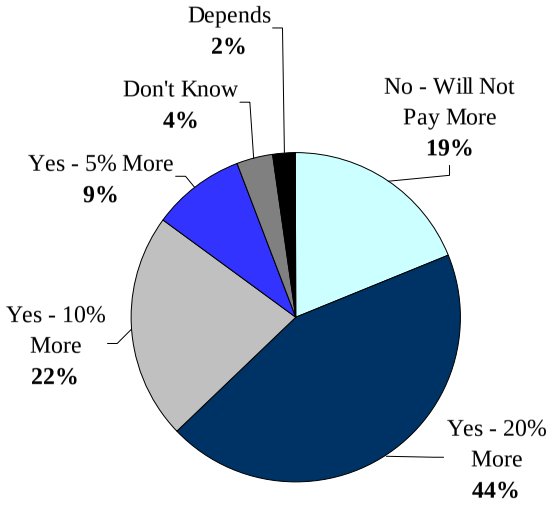
About two-thirds of customers are willing to pay a higher price for electricity if it was required to pay for new electrical generation.

Willingness to Pay a Higher Price for Electricity if this was Required to Pay for Electric Power
(Total Respondents)



Please Note: Question Asked Only of Respondents Who Provided a 'Consideration' Rating for at least One Generation Option

How Much More Customers Are Willing To Pay for Electric Power
(Among Residential Customers Who Would Definitely Consider At Least One Electricity Supply Option, n=743)



Residents in the Okanagan were more likely to say they would 'definitely' or 'likely' pay more compared to West Kootenay residents.

"While I would pay more for green electricity we all want the most we can get for the least."

Questions #'s:
Residential Survey Q..22 and Q.23
Commercial Survey Q.22

FORTISBC Communications

Section Highlights: Communications

At the time of this study, there was relatively low awareness of FortisBC's electrical supply plan.

- Newspapers were cited as the main source of recall for those who had some awareness.
- Three-quarters of survey respondents are interested in learning more about the electricity supply plan. Environmental implications and cost implications were cited as the top two areas of interest.

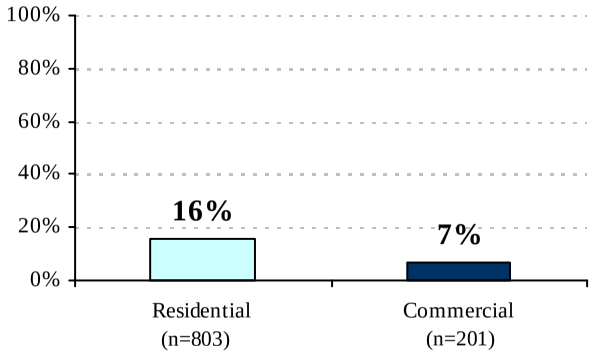
Thoughts for Consideration

- The workshops demonstrated that people exposed to more information can have a different perspective than those who do not. The workshop format can play a valuable role in engaging and educating customers.
- High levels of interest in the environmental and cost implications of the options FortisBC is considering suggest the topic areas where communications can focus.
- Media choice plays a key role. Those customers who recalled seeing or hearing something about FortisBC's plan cited newspapers, radio and television as the sources – suggesting that these media have high credibility and recall.
- As customers in the area generally do not think energy and electricity are major concerns for the region, one of the tasks for communications is to create awareness of the need to think about it.

Recall of FortisBC's New Electrical Supply Plan

Very few customers recall hearing anything about FortisBC's new electrical supply plan. But among those who do recall hearing about the new plan, most cannot recall what they had heard.

Recall of New Electrical Supply Plan
(Total Respondents)



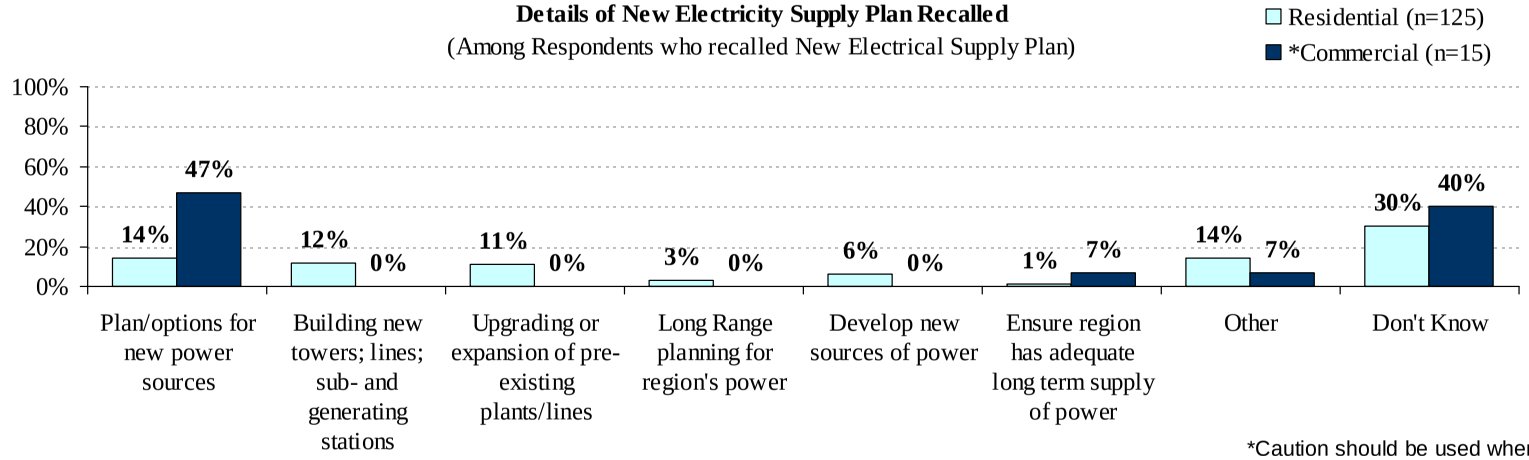
Residential respondents cited the following as sources of recall regarding FortisBC's new plan for electricity:

Newspaper	**44%**
Television	**22%**
Radio	**14%**
Flyers	**14%**

Commercial respondents cited the following as sources of recall regarding FortisBC's new plan for electricity:

Newspaper	**47%**
Television	**13%**
Radio	**27%**

Details of New Electricity Supply Plan Recalled
(Among Respondents who recalled New Electrical Supply Plan)



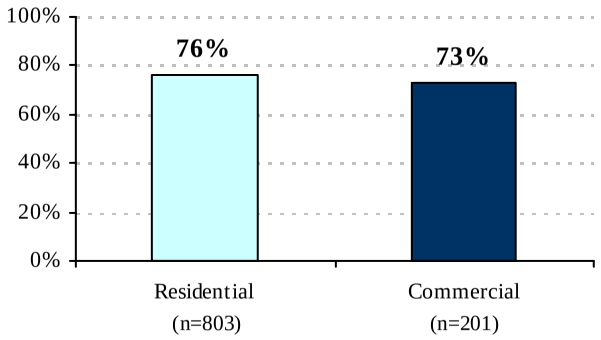
*Caution should be used when comparing results due to small base size.

Questions #'s:
Residential Survey Q.12, Q.13 and Q.16
Commercial Survey Q.12, Q.13 and Q.16

Customers Want to Know More

About three-quarters of customers are interested in learning more about the new electricity supply plan being developed by FortisBC. Of the most interest to customers are the environmental and cost implications as well as the benefits and costs of the options.

Interested in Learning more about the New Electricity Supply Plan
(Total Respondents)



Aspects of the Plan Most Interested in Leaning More About
(Total Respondents)

	Total Residential (n=610)
Environmental implications	30%
Cost implications	24%
Benefits and costs of options	20%
General information / anything / everything	15%
Sources they plan to use / proposals / planned projects	15%
How Plan fits with BC Energy Plan	10%
Wind	9%
Location of potential generating stations	8%
Opportunities for public consultation or input	8%
Transmission issues	7%
Conservation	5%
Biomass	3%
Power generation	3%
Other	4%
DK/NA	6%

	Total Commercial (n=146)
Environmental implications	32%
Cost implications	16%
Benefits and costs of options	16%
Wind power generation	10%
An outline of the future plan	10%
Transmission issues	8%
How Plan fits with BC Energy Plan	8%
Opportunities for public consultation or input	8%
Conservation	7%
Alternative options (general)	5%
Location of new energy sources	3%
Hydro electric power generation	3%
Pine beetle/burning dead trees	3%
Other	8%
DK/NA	20%

Note: Total responses less than 3% not reported.

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Questions #'s:
Residential Survey Q..26 and Q.27
Commercial Survey Q.26 and Q.27

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Participant Feedback on the Workshop Format

Workshop participants were complimentary on FortisBC's efforts to involve them in decision making and found it an educational experience.

"It is fantastic to have Fortis connect with residents before making a choice."

"More should be done as incentives for providing the public with a viable means of reducing energy consumption, i.e., chip program back in the 1980's as a means of better insulating homes (reduce heating costs, etc.)"

"I applaud your efforts to talk to us consumers and seek our input."

"Thank you for your interest in public opinion. We need more of this. I wish we (the crowd) had more positive input to offer!"

"Very informative, if more people participated in this type of thing it would probably motivate them to do something to contribute or reduce their own (environmental) input."

"I felt this to be very eye opening. I learned a lot from this. I feel I don't know very much about power and energy; or lack thereof."

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The Electrical Supply Options

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Section Highlights: The Electrical Supply Options

A solution that incorporates some form of hydro-electric generation appears to have the strongest support. But, no option emerged as an ideal solution.

- Large hydro was the option with the highest 'definitely consider' rating in the workshops; wind power was the favourite with the residential and commercial telephone survey respondents.
- Workshop participants were less likely to say that wind power, bio-mass plants, and small hydro 'should definitely be considered'. A greater proportion of respondents in the workshop rated these options as 'should consider'.
- Concerns about environmental impact were raised with all options, including large hydro-electric options.
- While large hydro emerged as the most preferred option in the workshops, the portfolio featuring natural gas and small hydro was the second most preferred option.
  - The low preference for natural gas options in the telephone survey suggests that the discussions in the workshops encouraged greater consideration of natural gas.
- Workshop discussions also encompassed forms of electrical generation not covered in the presentation, for example nuclear or solar power.

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Section Highlights: The Electrical Supply Options

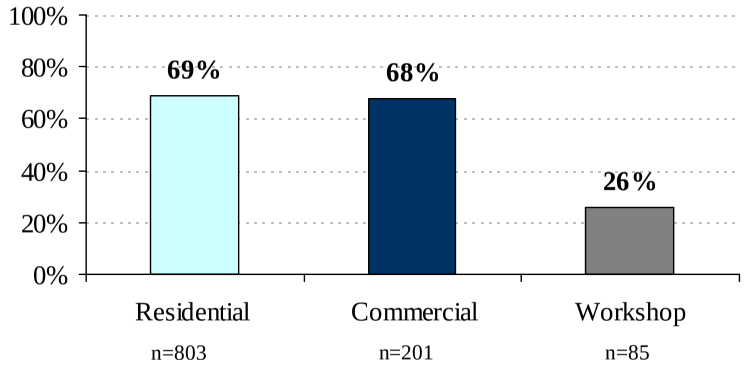
Thoughts for Consideration

- Residential and commercial customers responding to the telephone survey tended to reflect commonly held opinions, such as the low environmental damage caused by wind power. It may be that an electricity generation type has advantages that are not well known amongst customers, but it is a large communications challenge to try to change existing beliefs.
- Hydro-electric power generation is well-accepted in B.C. as reliable and cost-effective. In contrast, many residents have little experience with other forms of electricity generation, such as natural gas plants, and therefore may be more hesitant about considering them.
- Dialogue with the community about the impacts and advantages of different electricity generation options – particularly environmental impact, total cost, and cost/benefit – will make a difference.
- Some residents may want to know more about options which are not being considered, such as nuclear power or solar power.

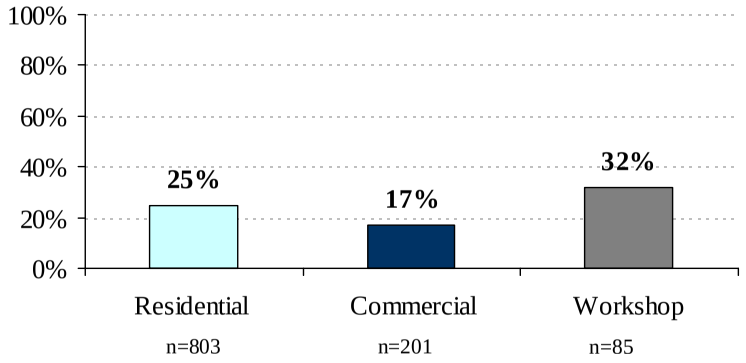
The Electrical Supply Options – Wind Power

Development of New Wind Power Stations in the Region, Using Large Scale Windmills Situated on "Wind Farms"

% Definitely Consider Option for the New Electrical Power Plan - Wind Power
(Total Respondents)



% Rating Option as having a Large Impact on the Environment - Wind Power
(Total Respondents)



Please Note: Large Impact is a combined total of Major and Moderate Impact

Questions #'s:

Residential Survey Q.19C and Q.21C

Commercial Survey Q.19C and Q.21C

Workshop Part 2: Q.1AC and Q.2C

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The Electrical Supply Options – Wind Power, cont'd

Development of New Wind Power Stations in the Region, Using Large Scale Windmills Situated on "Wind Farms"

Residential: Reasons Stated for Consideration of Option for New Electrical Power Plan – Wind Power
(Among Those Who Provided a Response at Q19)

	Total Residental
	(n=791)
It's a clean source/low environmental impact	43%
We have that source/it is viable for this region	11%
We don't have that resource/it's not viable for this region	7%
Cost-effective	6%
Implemented successfully elsewhere	5%
Depends (on the impact, if it's cost-effective, etc.)	4%
They are unsightly	3%
We need more power/all options should be considered	3%
Other	10%
DK/NA	3%

Note: Total responses less than 3% not reported.

Commercial: Reasons Stated for Consideration of Option for New Electrical Power Plan – Wind Power
(Among Those Who Provided a Response at Q19)

	Total Commercial
	(n=196)
It's environmentally friendly	24%
It's a clean source/low environmental impact	14%
There is a lot harnessable wind in the region	11%
Its a renewable/sustainable resource	10%
Its a good/natural resource that should be considered	10%
Cost-effective	6%
Not enough wind in the local region	6%
It's an alternative source of power	5%
Depends on where they are located	3%
Other	11%
DK/NA	1%

Note: Total responses less than 3% not reported.

Reasons Stated for Consideration of Option for New Electrical Power Plan – Wind Power
(Total Respondents)

	Total Workshop
	(n=85)
Less impact on environment	11%
Clean power	8%
NO ANSWER	73%

Note: Total responses less than 3% not reported.

Questions #'s:

Residential Survey Q.20C

Commercial Survey Q.20C

Workshop Part 2: Q.1BC

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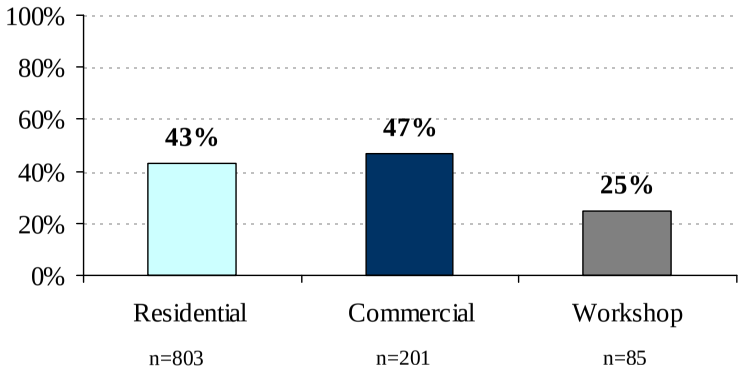
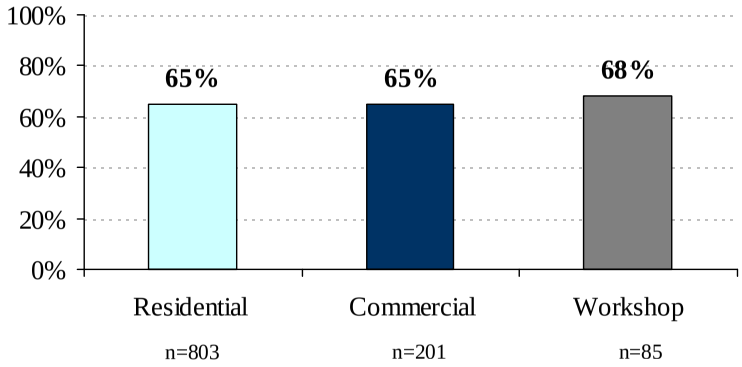
The Electrical Supply Options – Biomass Energy Plants

Development of Biomass Energy Plants, That Can Produce Electricity Through the Combustion of Dead Trees Killed by the Pine Beetle

% Definitely Consider Option for the New Electrical Power Plan - Biomass
(Total Respondents)



% Rating Option as having a Large Impact on the Environment - Biomass
(Total Respondents)



Please Note: Large Impact is a combined total of Major and Moderate Impact

Questions #'s:

Residential Survey Q.19D and Q.21D

Commercial Survey Q.19D and Q.21D

Workshop Part 2: Q.1AD and Q.2D

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Development of Biomass Energy Plants, That Can Produce Electricity Through the Combustion of Dead Trees Killed by the Pine Beetle

Reasons Stated for Consideration of Option for New Electrical Power Plan – Biomass
(Among Those Who Provided a Response at Q19)

	Total Residental
	(n=771)
A good method for utilising the wood that would otherwise be waste	23%
Environmental impact too high	16%
We have that source/it is viable for this region	16%
Not a long-term solution	6%
Depends (on the impact, if it's cost-effective, etc.)	6%
We need more power/all options should be considered	4%
It's a clean source/low environmental impact	4%
There are other/better uses for the wood	3%
Gets rid of pine beetles/controls forest fires	3%
Other	9%
DK/NA	4%

Note: Total responses less than 3% not reported.

Reasons Stated for Consideration of Option for New Electrical Power Plan – Biomass
(Among Those Who Provided a Response at Q19)

	Total Commercial
	(n=194)
Canada should be self-sufficient	19%
Should be kept locally/within Canada	14%
B.C. generates enough power/No need to import	7%
Only if the local power supply is not enough	6%
Importing may be more expensive	6%
Keeps employment/money within Canada	4%
Depends on environmental impacts	3%
Other	14%
DK/NA	25%

Note: Total responses less than 3% not reported.

Reasons Stated for Consideration of Option for New Electrical Power Plan – Biomass
(Total Respondents)

	Total Workshop
	(n=85)
Need a solution for all the rotting trees from the pine beetle	14%
Less impact on environment	6%
NO ANSWER	75%

Note: Total responses less than 3% not reported.

Questions #'s:

Residential Survey Q.20D

Commercial Survey Q.20D

Workshop Part 2: Q.1BD

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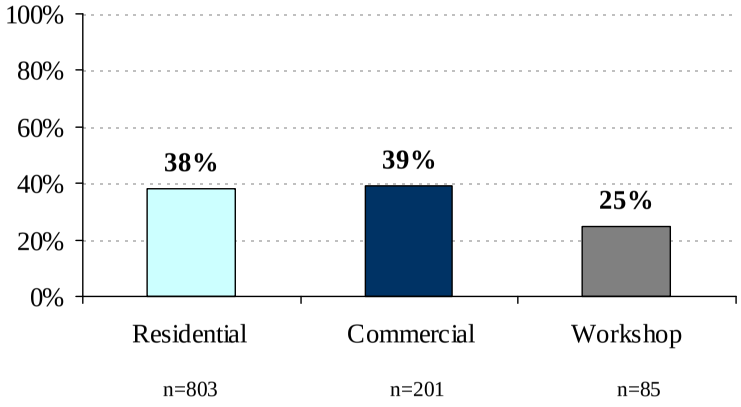
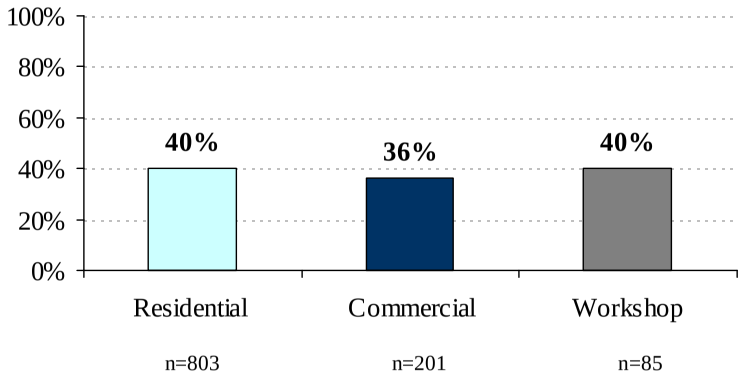
The Electrical Supply Options – Local Power Sources

Purchasing the Required Electricity From Other Power Producers in the Province

% Definitely Consider Option for the New Electrical Power Plan - Local Sources
(Total Respondents)



% Rating Option as having a Large Impact on the Environment - Local Sources
(Total Respondents)



Please Note: Large Impact is a combined total of Major and Moderate Impact

Questions #'s:

Residential Survey Q.19G and Q.21G

Commercial Survey Q.19G and Q.21G

Workshop Part 2: Q.1AG and Q.2G

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Purchasing the Required Electricity From Other Power Producers in the Province

Reasons Stated for Consideration of Option for New Electrical Power Plan – Local Sources
(Among Those Who Provided a Response at Q19)

	Total Residental
	(n=780)
Keeps the energy within Canada/B.C.	11%
Power is generated/purchased locally	6%
More preferable than cross-border sales	6%
Cheaper/more cost effective	5%
Some regions have an energy surplus	5%
B.C. should be self-sufficient	4%
Should be considered if necessary	4%
Its readily available	4%
Too expensive	4%
Need sustainable power	4%
Keeps employment/money within the province	3%
Depends on cost implications	3%
Low environmental impact	3%
Benefits the province	3%
It is not necessary	3%
Other	9%
DK/NA	8%

Note: Total responses less than 3% not reported.

Reasons Stated for Consideration of Option for New Electrical Power Plan – Local Sources
(Among Those Who Provided a Response at Q19)

	Total Commercial
	(n=196)
Keeps the power supply within B.C./Canada	14%
Shares resources that are locally abundant	12%
Supports the province/economy	8%
An alternative that should be considered if necessary	7%
Keeps employment/money with B.C.	5%
More preferable than depending on another country	5%
Need to have enough power	4%
Lowers the cost	4%
Depends on costs	3%
Other	12%
DK/NA	26%

Note: Total responses less than 3% not reported.

Reasons Stated for Consideration of Option for New Electrical Power Plan – Local Sources
(Total Respondents)

	Total Workshop
	(n=85)
Need to be self sufficient for our energy needs/not dependant on others	5%
This is reliable/makes sense long term	4%
It is cost efficient/less for the consumer to pay	4%
NO ANSWER	80%

Note: Total responses less than 3% not reported.

Questions #'s:
Residential Survey Q.20G
Commercial Survey Q.20G
Workshop Part 2: Q.1BG

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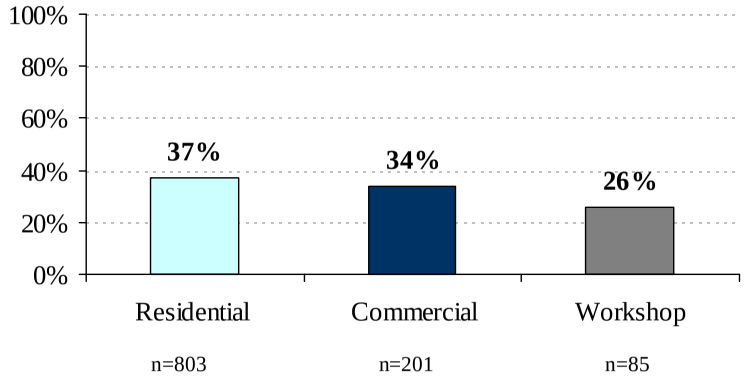
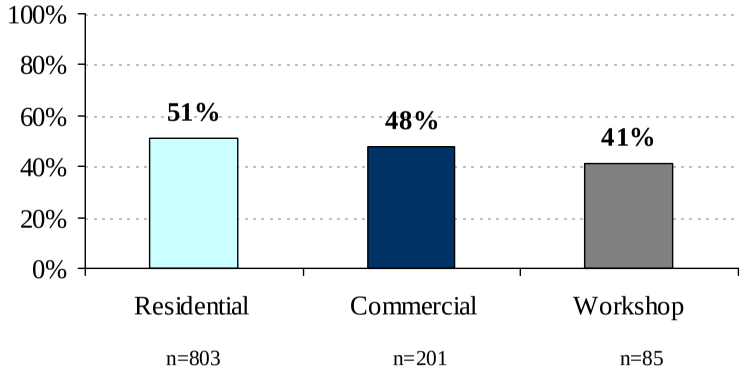
Development of Small Scale Hydro-Electric Power Projects on Rivers in the Region

% Definitely Consider Option for the New Electrical Power Plan - Small Scale Hydro
(Total Respondents)



% Rating Option as having a Large Impact on the Environment - Small Scale Hydro
(Total Respondents)



Please Note: Large Impact is a combined total of Major and Moderate Impact

Questions #'s:

Residential Survey Q.19A and Q.21A

Commercial Survey Q.19A and Q.21A

Workshop Part 2: Q.1AA and Q.2A

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The Electrical Supply Options – Small Scale Hydro, cont'd

Development of Small Scale Hydro-Electric Power Projects on Rivers in the Region

Reasons Stated for Consideration of Option for New Electrical Power Plan – Small Scale Hydro (Among Those Who Provided a Response at Q19)

	Total Residental
	(n=758)
Environmental impact too high	18%
We have that resource/it is viable for this region	14%
It's a clean source/low environmental impact	14%
Depends (on the impact, if it's cost-effective, etc.)	8%
Superior in comparison to other options	4%
Promotes self-sufficiency/requires shorter corridors	3%
We need more power/all options should be considered	3%
We don't have that resource/it's not viable for this region	3%
Cost-effective	3%
Inferior in comparison to other options	3%
Other	14%
DK/NA	8%

Note: Total responses less than 3% not reported.

Reasons Stated for Consideration of Option for New Electrical Power Plan – Small Scale Hydro (Among Those Who Provided a Response at Q19)

	Total Commercial
	(n=187)
Lessens the environmental impact	19%
It's a local resource that should be used	17%
Causes more environmental damage	16%
Depends on its environmental impact	6%
There are already enough local dams	5%
Cheaper/more economical	5%
Need to have enough power	4%
Depends on where the dams are located	3%
Constructing the dams would be too expensive	3%
Other options should be considered	3%
It's a renewable resource	3%
Other	9%
DK/NA	8%

Reasons Stated for Consideration of Option for New Electrical Power Plan – Small Scale Hydro (Total Respondents)

	Total Workshop
	(n=85)
Less impact on environment	12%
It is cost efficient/less for the consumer to pay	4%
Unreliable/not long term	4%
DK/NA	69%

Questions #'s:

Residential Survey Q.20A

Commercial Survey Q.20A

Workshop Part 2: Q.1BA

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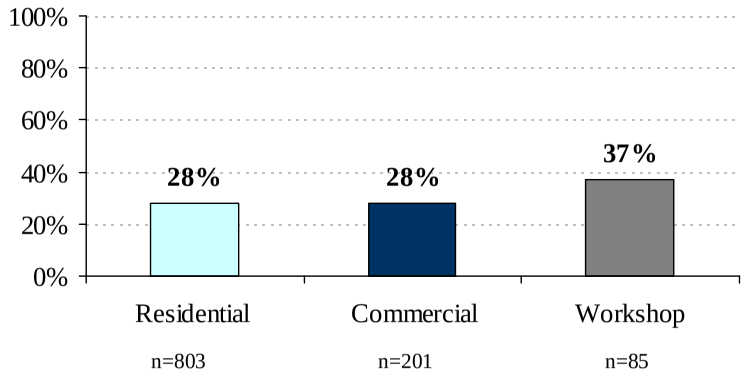
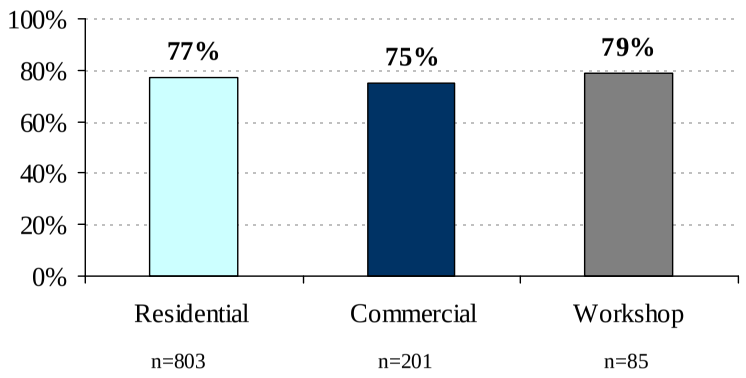
The Electrical Supply Options – Large Scale Hydro

Development of a Single Large Hydro-Electric Power Generating Station Located in the Province

% Definitely Consider Option for the New Electrical Power Plan - Large Scale Hydro
(Total Respondents)



% Rating Option as Having a Large Impact on the Environment - Large Scale Hydro
(Total Respondents)



Please Note: Large Impact is a combined total of Major and Moderate Impact

Questions #'s:

Residential Survey Q.19B and Q.21B

Commercial Survey Q.19B and Q.21B

Workshop Part 2: Q.1AB and Q.2B

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The Electrical Supply Options – Large Scale Hydro, cont'd

Development of a Single Large Hydro-Electric Power Generating Station Located in the Province

Reasons Stated for Consideration of Option for New Electrical Power Plan – Large Scale Hydro
(Among Those Who Provided a Response at Q19)

	Total Residental
	(n=741)
Environmental impact too high	15%
Inferior in comparison to other options	10%
We need more power/all options should be considered	10%
Depends (on the impact, if it's cost-effective, etc.)	9%
Promotes self-sufficiency/requires shorter corridors	7%
It's a clean source/low environmental impact	6%
Superior in comparison to other options	5%
We have that source/it is viable for this region	4%
Centralization is undesirable/problems of supply if the sole dam falters	4%
Cost-effective	3%
Other	8%
DK/NA	13%

Note: Total responses less than 3% not reported.

Reasons Stated for Consideration of Option for New Electrical Power Plan – Large Scale Hydro
(Among Those Who Provided a Response at Q19)

	Total Commercial
	(n=187)
Causes more environmental damage	12%
It provides more local options for power generation	10%
Potential for a wide scale power outage	7%
Centralization is inefficient	7%
Need to have enough power	7%
Its a clean/good source of energy	7%
Depends on its environmental impact	6%
Depends on its location	5%
Other options should be considered	5%
Cheaper/more economical	5%
Easier to maintain than some other options	3%
There is an abundant supply of water	3%
Other	8%
DK/NA	13%

Reasons Stated for Consideration of Option for New Electrical Power Plan – Large Scale Hydro
(Total Respondents)

	Total Workshop
	(n=85)
This is reliable/makes sense long term	15%
Less impact on environment	11%
Can profit from excess power generated/good for BC economy	7%
It is cost efficient/less for the consumer to pay	5%
Working together makes sense	4%
It is a viable/efficient option	4%
DK/NA	59%

Questions #'s:
Residential Survey Q.20B
Commercial Survey Q.20B
Workshop Part 2: Q.1BB

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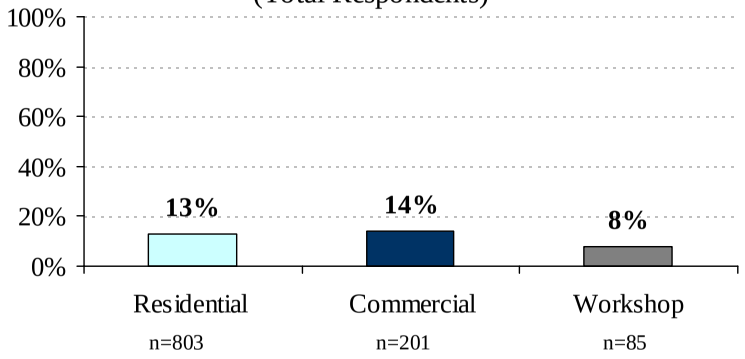
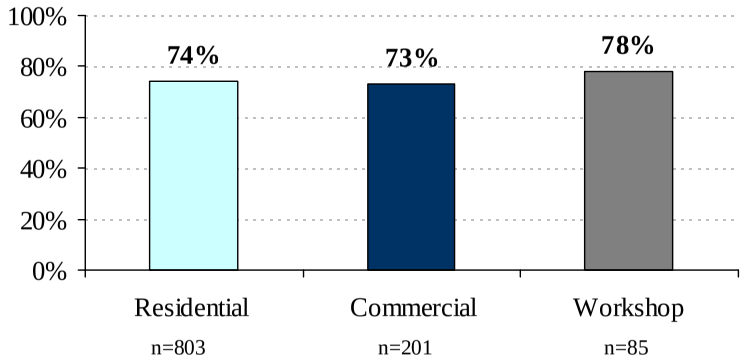
The Electrical Supply Options – Natural Gas Plants

Development of New Power Plants that Use Natural Gas to Produce Electricity

% Definitely Consider Option for the New Electrical Power Plan - Natural Gas Plants
(Total Respondents)



% Rating Option as having a Large Impact on the Environment - Natural Gas Plants
(Total Respondents)



Please Note: Large Impact is a combined total of Major and Moderate Impact

Questions #'s:
Residential Survey Q.19E and Q.21E
Commercial Survey Q.19E and Q.21E
Workshop Part 2: Q.1AE and Q.2E

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The Electrical Supply Options – Natural Gas Plants, cont'd

Development of New Power Plants that Use Natural Gas to Produce Electricity

Reasons Stated for Consideration of
Option for New Electrical Power Plan –Natural Gas Plants
(Among Those Who Provided a Response at Q19)

	Total Residental
	(n=728)
Environmental damage	19%
Too expensive	11%
Other options should be considered	9%
Is a non-renewable resource	7%
It's a clean energy source	7%
Have a good supply/could be cheaper/should use	7%
It's an alternative source of power	6%
Redundant/Inefficient	5%
Limited resource supply	5%
Against burning fossil fuels	3%
Other	5%
DK/NA	9%

Reasons Stated for Consideration of
Option for New Electrical Power Plan –Natural Gas Plants
(Among Those Who Provided a Response at Q19)

	Total Commercial
	(n=177)
Causes more environmental damage	15%
Too expensive	10%
It's provides more local options for power generation	7%
Against burning fossil fuels	7%
It's a clean energy source	6%
Other options should be considered	5%
Limited resource supply	4%
There is a lot of natural gas in the region	4%
It is not a renewable resource	3%
Should use hydro-electric power instead	3%
Other	7%
DK/NA	25%

Reasons Stated for Consideration of
Option for New Electrical Power Plan –Natural Gas Plants
(Total Respondents)

	Total Workshop
	(n=85)
This is reliable/makes sense long term	**2%**
Unreliable/not long term	**2%**
Cost is not effective	**2%**
DK/NA	**88%**

Questions #'s:

Residential Survey Q.20E

Commercial Survey Q.20E

Workshop Part 2: Q.1BE

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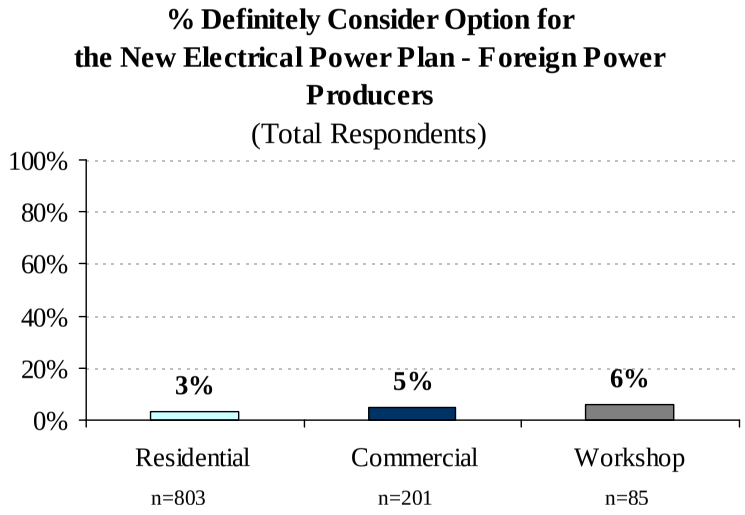
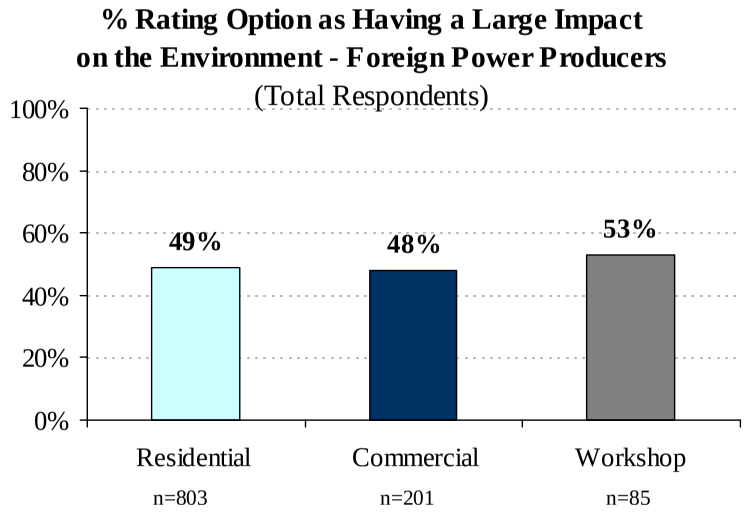
Purchasing the Required Electricity from Other Utilities in the US Through the Wholesale Market





Note: Large Impact is a combined total of Major and Moderate Impact

Questions #'s:

Residential Survey Q.19F and Q.21F

Commercial Survey Q.19F and Q.21F

Workshop Part 2: Q.1AF and Q.2F

The Electrical Supply Options – Foreign Power Producers, cont'd

Purchasing the Required Electricity from Other Utilities in the US Through the Wholesale Market

Reasons Stated for Consideration of Option for New Electrical Power Plan – Foreign Power Producers (Among Those Who Provided a Response at Q19)

	Total Residental
	(n=792)
Already sell to the US / Dislike idea of dealing with US	21%
Should be kept locally/within Canada	15%
Canada should be self-sufficient	12%
B.C. generates enough power/no need to import	8%
Importing may be more expensive	6%
Should use local resources	6%
Only if the local power supply is not enough	5%
Can generate the power in BC/Canada	5%
Sustainability/reliability Issues	4%
Depends on cost/environmental impacts/sustainability	3%
Could be cheaper	3%
Other	5%
DK/NA	5%

Note: Total responses less than 3% not reported.

Reasons Stated for Consideration of Option for New Electrical Power Plan – Foreign Power Producers (Among Those Who Provided a Response at Q19)

	Total Commercial
	(n=194)
Canada should be self-sufficient	19%
Should be kept locally/within Canada	14%
B.C. generates enough power/No need to import	7%
Only if the local power supply is not enough	6%
Importing may be more expensive	6%
Keeps employment/money within Canada	4%
Depends on environmental impacts	3%
Other	14%
DK/NA	25%

Note: Total responses less than 3% not reported.

Reasons Stated for Consideration of Option for New Electrical Power Plan – Foreign Power Producers (Total Respondents)

	Total Workshop
	(n=85)
Need to be self sufficient for our energy needs/not dependant on others	**5%**
Unreliable/not long term	**4%**
DK/NA	**87%**

Questions #'s:

Residential Survey Q.20F

Commercial Survey Q.20F

Workshop Part 2: Q.1BF

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Respondent Profile

Overall Respondent Profile – Residential & Workshop

Residential respondents tended to be homeowners of single family dwellings and over 35 years of age. Workshop participants tended to be younger and the West Kootenay workshop had higher participation.

	Total Residental	Total Workshop
Age	**(n=803)**	**(n=85)**
18 - 34	10%	15%
35 - 54	33%	44%
55 +	52%	41%
Refused	5%	-
Gender	**(n=803)**	**(n=85)**
Male	47%	55%
Female	53%	45%
Home Ownership	**(n=803)**	**(n=85)**
Own	86%	72%
Rent	13%	21%
Dwelling Type	**(n=803)**	**(n=85)**
Single family dwelling	85%	71%
Townhome or duplex	7%	12%
Low-rise apartment building	4%	12%
Other	3%	5%
Number of People In Household	**(n=803)**	**(n=85)**
1	17%	18%
2	47%	44%
3	13%	8%
4 OR MORE	20%	22%

	Total Residental	Total Workshop
Area	**(n=803)**	**(n=85)**
Okanagan	60%	42%
West Kootenay	40%	58%
Highest Level of Education	**(n=803)**	**N/A**
High school grad or less	38%	
Vocational	25%	
Post Secondary	35%	
Household Income	**(n=803)**	**N/A**
Under $20,000	12%	
$20,000 to under $40,000	22%	
$40,000 to under $60,000	15%	
$60,000 to under $80,000	14%	
$80,000 to under $100,000	8%	
$100,000 and over	9%	
Refused/ Don't Know	19%	
Employment Status	**N/A**	**(n=85)**
Working full-time		47%
Retired		27%
Working part-time		19%
Stay at home full-time		4%

Note: Total responses less than 3% not reported.

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Regional Profile Differences – Residential Customers

West Kootenay customers tend to own their homes. There is a significantly higher proportion of Okanagan residents who rent.

	Total	Okanagan	West Kootenay
Age	**(n=803)**	**(n=480)**	**(n=323)**
18 - 34	10%	11%	8%
35 - 54	33%	33%	34%
55 +	52%	52%	53%
Refused	5%	5%	5%
Gender	**(n=803)**	**(n=480)**	**(n=323)**
Male	47%	49%	44%
Female	53%	51%	56%
Home Ownership	**(n=803)**	**(n=480)**	**(n=323)**
Own	86%	82%	91%
Rent	13%	17%	8%
Dwelling Type	**(n=803)**	**(n=480)**	**(n=323)**
Single family dwelling	85%	79%	93%
Townhome or duplex	7%	11%	2%
Low-rise apartment building	4%	6%	1%
Other	3%	2%	3%
Number of People In Household	**(n=803)**	**(n=480)**	**(n=323)**
1	17%	16%	19%
2	47%	49%	44%
3	13%	13%	14%
4 OR MORE	20%	19%	20%

	Total	Okanagan	West Kootenay
Area	**(n=803)**	**(n=480)**	**(n=323)**
Okanagan	60%	100%	
West Kootenay	40%		100%
Highest Level of Education	**(n=803)**	**(n=480)**	**(n=323)**
High school grad or less	38%	40%	36%
Vocational	25%	25%	25%
Post Secondary	35%	32%	38%
Household Income	**(n=803)**	**(n=480)**	**(n=323)**
Under $20,000	12%	13%	11%
$20,000 to under $40,000	22%	21%	23%
$40,000 to under $60,000	15%	13%	19%
$60,000 to under $80,000	14%	15%	14%
$80,000 to under $100,000	8%	8%	7%
$100,000 and over	9%	10%	8%
Refused/ Don't Know	19%	20%	18%

Note: Total responses less than 3% not reported.

Indicates a statistically significant difference between the Okanagan and West Kootenay Region

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Regional Profile Differences – Residential Customers, cont'd

Okanagan customers tend to have a higher awareness of short and long term energy supply problems compared to West Kootenay customers.

	Total	Okanagan	West Kootenay
Most Important Issue Facing Region Today	**(n=803)**	**(n=480)**	**(n=323)**
Health care	17%	23%	9%
Unemployment	8%	5%	13%
Growth/urban development	8%	8%	7%
Water (drinking water, supply, etc.)	7%	8%	5%
Affordable housing	5%	6%	4%
Economy/interest rates	4%	4%	5%
Electricity costs/prices	4%	3%	6%
Forestry (practices, economics of, etc.)	3%	2%	4%
Other	8%	6%	12%
None	3%	3%	2%
Don't Know	11%	11%	11%
Most Important Issue - Generation and Use of Electricity Energy	**(n=803)**	**(n=480)**	**(n=323)**
Need to conserve/reduce consumption	17%	20%	12%
Price/cost of electricity	14%	14%	14%
Alternative energy sources (wind, solar, biofuels)	8%	9%	7%
Supply of electricity	8%	9%	6%
Environmental impacts of energy production	6%	5%	8%
Other	9%	9%	9%
None	4%	4%	4%
Don't Know	24%	25%	23%
Main Source of Electricity in Region	**(n=803)**	**(n=480)**	**(n=323)**
Hydro-electric power/Dams/Water power	73%	62%	90%
Natural Gas	7%	10%	3%
Other	8%	9%	8%
Don't Know	21%	30%	8%
Main Source of Electricity in Community	**(n=803)**	**(n=480)**	**(n=323)**
Hydro-electric power/Dams/Water power	69%	61%	83%
Natural Gas	11%	15%	4%
Other	9%	4%	12%
Don't Know	13%	20%	-

	Total	Okanagan	West Kootenay
Environmental Impact - South Central BC	**(n=803)**	**(n=480)**	**(n=323)**
Large Impact	51%	44%	58%
Small Impact	44%	50%	38%
Environmental Impact - Community Lived In	**(n=803)**	**(n=480)**	**(n=323)**
Large Impact	28%	23%	34%
Small Impact	67%	71%	63%
Electricity Supply Short Term (2 to 5 years)	**(n=803)**	**(n=480)**	**(n=323)**
More than enough	17%	11%	26%
As much as needed	42%	38%	48%
Less than needed	32%	40%	19%
Don't Know	8%	9%	7%
Electricity Supply Long Term (20 years)	**(n=803)**	**(n=480)**	**(n=323)**
More than enough	9%	4%	17%
As much as needed	20%	15%	26%
Less than needed	57%	69%	39%
Depends	5%	4%	7%
Don't know	10%	8%	11%
Price of Electricity	**(n=803)**	**(n=480)**	**(n=323)**
Too low	2%	1%	3%
About right	45%	42%	49%
Too high	51%	53%	47%
Impact on Household Finances	**(n=803)**	**(n=480)**	**(n=323)**
Noticeable impact	60%	57%	64%
Small impact	26%	28%	24%
No impact	11%	12%	9%

Note: Total responses less than 3% not reported.

Indicates a statistically significant difference between the Okanagan and West Kootenay Region

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Overall Respondent Profile - Commercial

Commercial customers were one-third small business and over three quarters of commercial customers have only one location in the region.

	Total Commercial
Job Title	**(n=201)**
Owner	47%
Manager/Account Manager/Area Manager	13%
President/Vice President	10%
Administrator	4%
CFO/CEO/COO	3%
Other	7%
Refused	6%
Organization Industry or Sector	**(n=201)**
Small business	31%
Retail	7%
Transportation / Logistics	6%
Healthcare / Medical Clinic / Hospital	4%
Various services	4%
Agriculture	4%
Resort/golf club	3%
Church	3%
Construction/housing	3%
Lumber	3%
Other	19%

	Total Commercial
Area	**(n=201)**
Okanagan	41%
West Kootenay	59%
Locations in Region	**(n=201)**
One location	80%
More than one location	16%
Refused	4%
Number of Employees in Region	**(n=201)**
None	2%
1	11%
2	16%
3	11%
4	8%
5 or more	44%
Refused	6%
Gender	**(n=201)**
Male	55%
Female	45%

Note: Total responses less than 3% not reported.

ENVIRONICS RESEARCH GROUP

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Regional Profile Differences – Commercial Customers

There were significantly more male commercial customers who participated in this study compared to female commercial customers.

	Total	Okanagan	West Kootenay
Job Title	**(n=201)**	**(n=82)**	**(n=119)**
Owner	47%	55%	42%
Manager/Account Manager/Area Manager	13%	11%	15%
President/Vice President	10%	10%	11%
Other	7%	7%	7%
DK/NA	6%	6%	6%
Administrator	4%	1%	6%
CFO/CEO/COO	3%	2%	3%
Organization Industry or Sector	**(n=201)**	**(n=82)**	**(n=119)**
Small business	31%	30%	31%
Retail	7%	7%	7%
Transportation / Logistics	6%	4%	8%
Healthcare / Medical Clinic / Hospital	4%	5%	4%
Various services	4%	2%	5%
Agriculture	4%	5%	3%
Resort/golf club	3%	6%	2%
Church	3%	-	6%
Construction/housing	3%	2%	4%
Lumber	3%	1%	5%
Non-profit/charity	2%	-	3%
Manufacturing	2%	4%	1%
Other	19%	26%	15%

	Total	Okanagan	West Kootenay
Locations in Region	**(n=201)**	**(n=82)**	**(n=119)**
One location	80%	80%	79%
More than one location	16%	16%	17%
Refused	4%	4%	4%
Number of Employees in Region	**(n=201)**	**(n=82)**	**(n=119)**
None	2%	4%	2%
1	11%	13%	9%
2	16%	10%	21%
3	11%	11%	11%
4	8%	7%	9%
5 or more	44%	46%	43%
Refused	6%	9%	5%
Area	**(n=201)**	**(n=82)**	**(n=119)**
Okanagan	41%	100%	-
West Kootenay	59%	-	100%
Gender	**(n=201)**	**(n=82)**	**(n=119)**
Male	55%	65%	48%
Female	45%	35%	52%

Note: Total responses less than 3% not reported.

Indicates a statistically significant difference between the Okanagan and West Kootenay Region

ENVIRONICS RESEARCH GROUP

FORTISBC

Appendix A: Residential Questionnaire

Residential Questionnaire

Environics Research Group.
February 6, 2008

FortisBC
2008 Residential Customer Survey

FINAL Questionnaire

Introduction

Good afternoon/evening. My name is _____ and I am calling from Environics Research Group, a public opinion research company. Today we are conducting a survey on behalf of FortisBC among residents in Southern B.C. on important issues facing the region. Please be assured that we are not selling or soliciting anything. This survey is registered with the national survey registration system.

IF ASKED: The survey will take about 15 minutes to complete
IF ASKED: I can tell you at the end who sponsored this survey

IF ASKED: The registration system has been created by the Canadian survey research industry to allow the public to verify that a survey is legitimate, get information about the survey industry or register a complaint. The registration systems toll-free telephone number is 1-800-554-9996.

We would like to speak with the person who is the head of your household, or the person who normally pays the utility bills.

IF PERSON SELECTED IS NOT AVAILABLE, ARRANGE FOR CALL-BACK

A. Energy/Electricity Issues (13 questions)

I would like to start with a few general questions about the South Central region of B.C. where you live . . .

1. What would you consider to be the most important issue facing your region today?
DO NOT READ - CODE ONE ONLY

01 - Hydro/energy/electricity (PROBE FOR SPECIFICS ON THE ISSUE)
02 - Electricity – supply/reliability
03 - Electricity costs/prices
04 - Electricity – environmental issues
05 - Energy supply/reliability (PROBE FOR SPECIFICS)
06 - Environment/pollution (PROBE FOR SPECIFICS)
07 - Growth/urban development
08 – Infrastructure/roads
09 - Health care
10 - Unemployment
11 - Education issues
12 - Economy/interest rates
13 - Liberal/Campbell gov't/Provincial gov't - non-specific
14 - Deficit/public debt
15 - Taxes
16 - Crime/law and order
17 - Poverty/homelessness
18 - Cost of gas/fuel/heating costs (PROBE FOR SPECIFICS – WHICH FUEL TYPE(S))
97 - None
98 - Other (SPECIFY _____)
99 - DK/NA

2. And what issue do you think is the most important for the region, with respect to the generation and use of electrical energy?
DO NOT READ – CODE ONLY

01 – Price/cost of energy (PROBE FOR SPECIFIC TYPE OF ENERGY)
02 – Price/cost of electricity
03 – Supply of energy/having enough/running out (PROBE FOR SPECIFIC TYPE OF ENERGY)
04 – Supply of electricity
05 – Power outages/blackouts
06 – Alternative energy sources (wind, solar, biofuels)
07 – Environmental impacts of energy production
08 – Environmental impacts of energy consumption
09 – Need to conserve/reduce consumption
10 – New B.C. Energy Plan
98 – Other (SPECIFY _____)
97 – None
99 – DK/NA

3. What are the main sources or means by which electricity is generated to supply the needs of homes and businesses in you region today?
DO NOT READ - CODE ALL THAT APPLY. IF SAY ONLY "HYDRO-ELECTRIC", PROBE:
Do you mean power generated from dams on rivers and streams?
IF SAY "ELECTRICITY", PROBE And can you tell me how this electricity is generated?

01 - Oil
02 - Natural Gas
03 - Hydro-electric power/Dams/Water power
04 - Nuclear Power
05 - Coal
06 - Wind energy/windmills
07 - Solar energy
08 - Electricity imported from U.S. PROBE FOR HOW US POWER IS GENERATED
98 - Other (SPECIFY _____)
98 - DK/NA SKIP TO Q.7

4. And can you tell me which of these sources of energy is the one most likely used to produce the electricity provided to your own local community?
READ LIST FROM Q.3 IF NECESSARY - CODE ONLY ONE
IF ONLY ONE SOURCE MENTIONED IN Q.3, ASK:
And would you say this is the source of energy likely used to produce the electricity provided to your local community?

01 - Oil
02 - Natural Gas
03 - Hydro-electric power/Dams/Water power
04 - Nuclear Power
05 - Coal
06 - Wind energy/windmills
07 - Solar energy
08 - Electricity imported from U.S.
VOLUNTEERED
96 - More than one likely source
98 - Other (SPECIFY _____)
97 - Depends (i.e. input to power grid)
99 - DK/NA

Residential Questionnaire

5. As far as you know, does the generation of electric power using (NAME SOURCE OR SOURCES MENTIONED IN Q.3) cause major, moderate, minor or no damage to the environment in..... READ IN SEQUENCE

   a. The South Central region of B.C.

   b. The community where you live

   01 - Major impact
   02 - Moderate impact
   03 - Minor impact
   04 – No Impact
   VOLUNTEERED
   99 - DK/NA

6. (IF MAJOR OR MODERATE DAMAGE TO Q.5a OR b) Would you say the environmental damage caused by this generation of electric power is fully acceptable, somewhat acceptable, somewhat unacceptable, or fully unacceptable, given the important benefits provided by the supply of this power to homes and businesses in the region?

   01 - Fully acceptable
   02 - Somewhat acceptable
   03 - Somewhat unacceptable
   04 - Fully unacceptable
   VOLUNTEERED
   97 - Depends
   99 - DK/NA

7. I would now like to ask you about your region's supply of electrical energy; that is, the energy generated by electrical power stations that is then distributed by power lines to homes and businesses. From what you know or have heard, do you think the region currently has more than enough, as much as is needed, or less than is needed, to meet the region's demand for electrical power over the next two to five years?

   01 – More than enough
   02 – As much as needed
   03 – Less than needed
   VOLUNTEERED
   04 – Depends
   99 – DK/NA

8. And what about the longer term? Do you think your region will have more than enough, as much as needed, or less than is needed to meet the electrical power demand 20 years from now?

   01 – More than enough
   02 – As much as needed
   03 – Less than needed
   VOLUNTEERED
   04 – Depends
   99 – DK/NA

9. How satisfied are you with the reliability of the electrical power service you currently receive at home; that is, service you can count on and the absence of power outages. Are you:

   01 – Very satisfied
   02 – Somewhat satisfied
   03 – Not very satisfied, or
   04 – Not at all satisfied
   VOLUNTEERED
   99 – DK/NA

10. Do you feel the price you currently pay for your household electricity service is:
    READ

    01 – Too low
    02 – About right
    03 – Too high
    VOLUNTEERED
    04 – Depends
    99 – DK/NA

11. Does the current size of your household electric or hydro bill make a noticeable, small or no impact on your household finances each month?

    01 – Noticeable impact
    02 – Small impact
    03 – No impact
    VOLUNTEERED
    04 - Depends
    99 – DK/NA

Now moving to another topic . . .

12. Do you recall hearing or seeing anything recently about a new "BC Energy Plan" recently announced by the province?

    01 – Yes
    02 – No SKIP TO Q.14
    99 – DK/NA SKIP TO Q.14

13 (IF YES TO Q.12) What specifically do you recall hearing or seeing about this plan?
DO NOT READ – CODE ALL THAT APPLY

    01 – Climate change/plan to address climate change
    02 – Targets to reduce greenhouse gas emissions
    03 – Reduce environmental impacts of energy
    04 – Develop new sources of power
    05 – Make BC more energy self-sufficient
    06 – Develop clean sources of energy
    07 – Reduce environmental impacts of energy generation
    08 – Ensure BC has adequate long term supply of power
    09 – Close down coal power plants
    10 – Improve energy efficiency/standards
    11 – Promote alternative energy sources
    98 – Other (SPECIFY_____)
    99 – DK/NA

B. FortisBC Planning Options (39 questions)

I would now like to ask you about FortisBC, which is the company that provides electricity service to the region and your community . . .

14. Do you recall hearing or seeing anything recently about a new electricity supply plan announced recently by FortisBC?

    01 – Yes
    02 – No SKIP TO Q.17
    VOLUNTEERED
    03 – Heard of plan by another utility/company
    99 – DK/NA SKIP TO Q.17

15 (IF YES TO Q.14) What specifically do you recall hearing or seeing about this plan?
DO NOT READ – CODE ALL THAT APPLY

    01 – Plan/options for new power sources
    02 – Long range planning for region's power
    03 – Different options for meeting region's long term power needs
    04 – Develop new sources of power
    05 – Ensure region has adequate long term supply of power
    06 – Promote alternative energy sources
    98 – Other (SPECIFY_____)
    99 – DK/NA

16. Where specifically do you recall hearing or seeing something about FortisBC's new plan for electricity supply?
DO NOT READ – CODE ALL THAT APPLY

    01 – TV
    02 – Radio
    03 – Newspaper
    04 – Friends/family members
    05 – Workplace/co-workers
    06 – Flyers
    98 – Other (SPECIFY_____)
    99 – DK/NA

17. FortisBC is developing a comprehensive Resource Plan for meeting the region's electric power needs over the next 20 years. This plan identifies the anticipated growth and need for electric power to the year 2027, and identifies different options for meeting this demand that can best meet its objective of ensuring safe, cost-effective and reliable energy for its customers.

    There are number of factors to be considered in identifying the best options for providing long term power for the region. Please tell me if you think each of the following considerations is critically important, important but not critical, or not very important in deciding which electrical supply options should be selected?
    READ AND ROTATE

    a. Minimizing the environmental impacts of power generation

    b. Minimizing the environmental and land use impacts of building new transmission corridors to bring the power from where it is generated to where it is used

    c. Keeping down the cost of electricity charged to customers

    d. Ensuring a reliable source of power

    e. Generating power within BC rather than importing it from the U.S.

    f. Meeting the goals of the new BC Energy Plan

    01 – Critically important
    02 – Important but not critical
    03 – Not very important
    VOLUNTEERED
    04 – Not at all important
    05 – Depends
    99 – DK/NA

18. (IF MORE THAN ONE IN Q.17 IS CRITICALLY IMPORTANT) Among the considerations you identified as critically important, which one do you think is the most important of all?
READ ITEMS FROM Q.17 RATED AS CRITICALLY IMPORTANT, IN SAME SEQUENCE – CODE ONE ONLY

    01 - Minimizing the environmental impacts of power generation
    02 - Minimizing the environmental and land use impacts of building new transmission corridors to bring the power from where it is generated to where it is used
    03 - Keeping down the cost of electricity charged to customers
    04 - Ensuring a reliable source of power
    05 - Generating power within BC rather than importing it from the US
    06 - Meeting the goals of the new BC Energy Plan
    VOLUNTEERD
    07 – All equally important
    08 - Depends
    98 – Other (SPECIFY _____)
    99 – DK/NA

Residential Questionnaire

19. The FortisBC Resource Plan projects a rising demand for electric power in the region over the next 20 years, and identifies several options for how to generate the required amount of power over this timeframe.

    I will read you a list of options being considered. For each, please tell me whether you think this option should definitely be considered, likely be considered, likely not be considered or definitely not be considered for the new electrical power plan for the region.
    READ AND ROTATE – ASK WHY QUESTION (Q.20) AFTER EACH ITEM IS READ

    a. Development of small scale hydro-electric power projects on rivers in the region

    b. Development of a single large hydro-electric power generating station located in the province

    c. Development of new wind power stations in the region, using large scale windmills situated on "wind farms"

    d. Development of biomass energy plants, which can produce electricity through the combustion of dead trees killed by the Pine Beetle

    e. Development of new power plants that use natural gas to produce electricity

    f. Purchasing the required electricity from other utilities in the U.S through the wholesale market.

    g. Purchasing the required electricity from other power producers in B.C.

    01 – Definitely consider
    02 – Likely consider
    03 – Likely not consider
    04 – Definitely not consider
    VOLUNTEERED
    05 – Depends
    99 – DK/NA DO NOT ASK Q.20

DEFINTIONS FOR Q.19 – READ ONLY IF ASKED

Q19a./Q19b. READ ONLY IF ASKED WHAT HYDRO-ELECTRIC IS – Hydroelectricity is where the energy of moving water is converted to electric energy and conveyed along transmission lines to your home.

Q19c. READ ONLY IF ASKED WHAT WIND FARMS ARE – A wind farm is a power plant that uses windmills or wind turbines to generate electricity.

Q19d. READ ONLY IF ASKED WHAT BIOMASS ENERGY IS – Biomass energy is produced by the processing of organic materials such as wood, straw or manure.

20 Why do you say that?
SPECIFY

a. Development of small scale hydro-electric power projects on rivers in the region

b. Development of a single large hydro-electric power generating station located in the province

c. Development of new wind power stations in the region, using large scale windmills situated on "wind farms"

d. Development of biomass energy plants, that can produce electricity through the combustion of dead trees killed by the Pine Beetle

e. Development of new power plants that use natural gas to produce electricity

f. Purchasing the required electricity from other utilities in the U.S through the wholesale market.

g. Purchasing the required electricity from other power producers in B.C.

_____
99 – DK/NA

21. From what you know or have heard, how would you rate each of these electric power options in terms of its impact on the environment? Would you say that generating and supplying electricity to the region through {READ IN SEQUENCE} would have a major, moderate, minor or no impact on the environment?
READ IN SAME SEQUENCE AS IN Q.19

    a. Small scale hydro-electric power projects

    b. Large hydro-electric power generating stations

    c. Wind power stations in the region, using large scale windmills situated on "wind farms"

    d. Biomass energy plants, using dead trees killed by the Pine Beetle

    e. Power plants that use natural gas

    f. Purchasing the required electricity from other utilities in the U.S

    g. Purchasing the required electricity from other power producers in the province

    01 - Major impact
    02 - Moderate impact
    03 - Minor impact
    04 - No Impact
    VOLUNTEERED
    99 - DK/NA

DEFINTIONS FOR Q.21 – READ ONLY IF ASKED

Q21a./Q21b. READ ONLY IF ASKED WHAT HYDRO-ELECTRIC IS – Hydroelectricity is where the energy of moving water is converted to electric energy and conveyed along transmission lines to your home.

Q21c. READ ONLY IF ASKED WHAT WIND FARMS ARE – A wind farm is a power plant that uses windmills or wind turbines to generate electricity.

Q21d. READ ONLY IF ASKED WHAT BIOMASS ENERGY IS – Biomass energy is produced by the processing of organic materials such as wood, straw or manure.

Residential Questionnaire

8. Many of the options included in Question 7 would require new transmission infrastructure such as substations and transmission towers to relay the electricity from the place it is generated to the FortisBC service region. The expected transmission impact includes both the financial cost of building the transmission lines and the environmental impact.

   FortisBC's assessment of the transmission impact of each option is shown in Column B.

   Considering the assessment you gave for each option in Q.7 and the expected transmission impact shown in Column B, please **RANK** the options in Column C, where a rank of **1 would be your most preferred** option and **8 would be your least preferred option**.

	COLUMN A: Energy Generation Option	COLUMN B: Expected Transmission Impact	COLUMN C: Your Rank (1 to 8)
A	Buying more electricity from the wholesale energy market, which is supplied by U.S., Alberta and other B.C. power companies	**Medium to High**	
B	Development of a Combined Cycle Gas Turbine plant that would generate enough electricity to meet FortisBC's projected customer demand until 2020	**Very Low to Low**	
C	Development of large hydro-electric dams outside the FortisBC territory that would provide additional electricity at peak demand times to supplement electricity purchases from the wholesale energy market	**Medium to High**	
D	A combination of bio-mass wood waste plants, a large wind farm, and small hydro-electric dams on waterways within the FortisBC territory to supplement electricity purchases from the wholesale energy market	**High**	
E	A combination of a Simple Cycle Gas Turbine plant, a Combined Cycle Gas Turbine plant and a large-scale Wind Farm	**Medium to High**	
F	A combination of a Simple Cycle Gas Turbine plant, a Combined Cycle Gas Turbine plant and small hydro-electric dams on waterways within the FortisBC territory	**Low to Medium**	
G	Purchasing the required electricity from other power producers in B.C.	**Medium to High**	
H	Development of large hydro-electric dams in areas outside FortisBC's territory that would generate enough electricity to meet FortisBC's projected customer demand	**High**	

24. Another way to address the electric power needs of the region is through energy conservation, which can be defined simply as making conscious decisions and actions to reduce ones use of energy, which might involve being more efficient or cutting back the amount of energy used.

    Do you think energy conservation can play a major role, a moderate role, a minor role, or no role at all in ensuring the region has the supply of power it will need over the next 20 years?

    01 - Major role
    02 - Moderate role
    03 - Minor role
    04 – No role at all
    VOLUNTEERED
    99 - DK/NA

25. Do you think that individual consumers such as yourself can definitely, likely, likely not or definitely not make an important contribution to reducing the overall amount of electrical energy used in the region?

    01 – Definitely
    02 – Likely
    03 – Likely not
    04 – Definitely not
    VOLUNTEERED
    05 – Depends
    99 – DK/NA

26. Are you interested in learning more about the new electricity supply plan being developed by FortisBC?

    01 – Yes
    02 – No SKIP TO Q.28
    99 – DK/NA SKIP TO Q.28

27. (IF YES TO Q.26) What aspects of this Plan are you most interested in learning more about?
    DO NOT READ – CODE ALL THAT APPLY

    01 – Benefits and costs of options
    02 – Cost implications
    03 – Environmental implications
    04 – Transmission issues
    05 – Opportunities for public consultation/input
    06 – How Plan fits with BC Energy Plan
    98 – Other (SPECIFY _____)
    99 – DK/NA

ENVIRONICS RESEARCH GROUP

FORTISBC

Residential Questionnaire

C. Respondent Characteristics (7 questions)

To finish up, I would like to ask you a few questions about you and your household for statistical purposes only. Please be assured that your answers will remain completely confidential.

28.. Do you currently own or rent your home?

01 – Own
02 – Rent
99 – DK/NA/REFUSE

29. Which of the following best describes your home?

01 – Single family dwelling
02 – Townhome or duplex
03 – Low-rise apartment building
04 – High rise apartment building
VOLUNTEERED
05 – Farm
98 – Other (SPECIFY _____)
99 – NA/REFUSE

30. How many people, including yourself, currently live in your household?
SPECIFY NUMBER

___
99 – NA/REFUSE

31. Which is the last level of education that you have completed?
DO NOT READ – CODE ONE ONLY – DO NOT PROBE IN JUDGEMENTAL WAY

01 - Grade school or less
02 - Some high school
03 - High school grad
04 - Vocational/Technical school
05 - Some university
06 - University grad
07 - Postgraduate degree
99 – NA/REFUSE

32. In what year were you born?

_____
99 – NA/REFUSE

33. For statistical purposes only, please tell me which of the following categories applies to your total household income for the year 2007?
READ - CODE ONE ONLY – STOP ONCE RESPONDENT CONFIRMS CATEGORY

01 - Under $20,000
02 - $20,000 to under $40,000
03 - $40,000 to under $60,000
04 - $60,000 to under $80,000
05 - $80,000 to under $100,000
06 - $100,000 and over
VOLUNTEERED
99 - REFUSE/DK/NA

34. And to better understand how results vary by region, may I have the six digits of your postal code?

___ ___
999999 - DK/NA

This completes the survey. In case my supervisor would like to verify that I conducted this interview, may I please have your first name?

First Name: _____

Thank you for your time and assistance with this survey. It was conducted on behalf of FortisBC, and is intended to help guide the development of the new Resource Plan.

IF REQUESTED – PROVIDE CONTACT NAME/NUMBER AT FortisBC

The FortisBC contact centre customer service number is 1-866-4FORTIS (1-866-436-7847). The contact centre is open 0700-1900hrs Monday – Friday.

END CALL

RECORD

37. Gender

01 - Male
02 – Female

Appendix B: Commercial Questionnaire

Commercial Questionnaire

Environics Research Group.
February 6, 2008

FortisBC
2008 Commercial Customer Survey

FINAL Questionnaire

Introduction

Good afternoon/evening. My name is _____ and I am calling from Environics Research Group, a public opinion research company. Today we are conducting a short survey on behalf of FortisBC with a sample of its important commercial customers, on the topic of energy supply planning.

I would like to speak to the person in your organization who is responsible for making decisions regarding electricity. IF UNSURE OR ASKED TO BE MORE SPECIFIC: May I speak to someone authorized to speak on the company's behalf such as a manager or owner.

WHEN TRANSFERRED TO NEXT PERSON, REPEAT INTRODUCTION

IF ASKED: The survey will take about 15 minutes to complete
IF ASKED: Please be assured that we are not selling or soliciting anything. This survey is registered with the national survey registration system.

IF ASKED: The registration system has been created by the Canadian survey research industry to allow the public to verify that a survey is legitimate, get information about the survey industry or register a complaint. The registration systems toll-free telephone number is 1-800-554-9996.

This survey is about electrical power planning for the region, and we are not collecting any detailed specific information about your organization. We would like to interview you as a representative of your organization, but none of your responses will be attributed to you or your organization specifically, and neither you nor your organization will be identified in any of the reporting of results back to FortisBC.

IF PERSON SELECTED IS NOT AVAILABLE, ARRANGE FOR CALL-BACK

A. Energy/Electricity Issues

I would like to start with a few general questions about the South Central region of B.C. where you live . . .

2. What would your organization consider to be the most important issue for the region, with respect to the generation and use of electrical energy?
DO NOT READ – CODE ONLY

01 – Price/cost of energy (PROBE FOR SPECIFIC TYPE OF ENERGY)
02 – Price/cost of electricity
03 – Supply of energy/having enough/running out (PROBE FOR SPECIFIC TYPE OF ENERGY)
04 – Supply of electricity
05 – Power outages/blackouts
06 – Alternative energy sources (wind, solar, biofuels)
07 – Environmental impacts of energy production
08 – Environmental impacts of energy consumption
09 – Need to conserve/reduce consumption
10 – New B.C. Energy Plan
98 – Other (SPECIFY _____)
97 – None
99 – DK/NA

7. I would like to ask you about the region's supply of electrical energy; that is, the energy generated by electrical power stations that is then distributed by power lines to homes and businesses. From what you know or have heard, do you think the region currently has more than enough, as much as is needed, or less than is needed, to meet the region's demand for electrical power over the next two to five years?

01 – More than enough
02 – As much as needed
03 – Less than needed
VOLUNTEERED
04 – Depends
99 – DK/NA

8. And what about the longer term? Do you think your region will have more than enough, as much as needed, or less than is needed to meet the electrical power demand 20 years from now?

01 – More than enough
02 – As much as needed
03 – Less than needed
VOLUNTEERED
04 – Depends
99 – DK/NA

9. How satisfied is your organization with the reliability of the electrical power service currently provided to your operations in the region; that is, service you can count on and the absence of power outages. Are you:

01 – Very satisfied
02 – Somewhat satisfied
03 – Not very satisfied, or
04 – Not at all satisfied
VOLUNTEERED
99 – DK/NA

10. Do you feel the price your organization currently pays for your electricity service is:
READ

01 – Too low
02 – About right
03 – Too high
VOLUNTEERED
04 – Depends
99 – DK/NA

11. Does the current size of your organization's electric or hydro bill a significant, moderate or minor part of your overall operational budget?

01 – Significant
02 – Moderate
03 – Minor
VOLUNTEERED
04 – Depends
98 – Other (SPECIFY _____)
99 – DK/NA

Commercial Questionnaire

Now moving to another topic . . .

12. Do you recall hearing or seeing anything recently about a new "BC Energy Plan" recently announced by the province?

    01 – Yes
    02 – No SKIP TO Q.14
    99 – DK/NA SKIP TO Q.14

13 (IF YES TO Q.12) What specifically do you recall hearing or seeing about this plan?
DO NOT READ – CODE ALL THAT APPLY

    01 – Climate change/plan to address climate change
    02 – Targets to reduce greenhouse gas emissions
    03 – Reduce environmental impacts of energy
    04 – Develop new sources of power
    05 – Make BC more energy self-sufficient
    06 – Develop clean sources of energy
    07 – Reduce environmental impacts of energy generation
    08 – Ensure BC has adequate long term supply of power
    09 – Close down coal power plants
    10 – Improve energy efficiency/standards
    11 – Promote alternative energy sources
    98 – Other (SPECIFY_____)
    99 – DK/NA

B. FortisBC Planning Options

14. Do you recall hearing or seeing anything recently about a new plan announced recently by FortisBC?

    01 – Yes
    02 – No SKIP TO Q.17
    99 – DK/NA SKIP TO Q.17

15 (IF YES TO Q.14) What specifically do you recall hearing or seeing about this plan?
DO NOT READ – CODE ALL THAT APPLY

    01 – Plan/options for new power sources
    02 – Long range planning for region's power
    03 – Different options for meeting region's long term power needs
    04 – Develop new sources of power
    05 – Ensure region has adequate long term supply of power
    06 – Promote alternative energy sources
    98 – Other (SPECIFY_____)
    99 – DK/NA

16. Where specifically do you recall hearing or seeing something about FortisBC's new plan for electricity supply?
DO NOT READ – CODE ALL THAT APPLY

    01 – TV
    02 – Radio
    03 – Newspaper
    04 – Friends/family members
    05 – Workplace/co-workers
    06 – Flyers
    98 – Other (SPECIFY_____)
    99 – DK/NA

17. FortisBC is developing a comprehensive Resource Plan for meeting the region's electric power needs over the next 20 years. This plan identifies the anticipated growth and need for electric power to the year 2027, and identifies different options for meeting this demand that can best meet its objective of ensuring safe, cost-effective and reliable energy for its customers.

    There are number of factors to be considered in identifying the best options for providing long term power for the region. Please tell me - from the perspective of your organization - if you think each of the following considerations is critically important, important but not critical, or not very important in deciding which electrical supply options should be selected?
    READ AND ROTATE

    a. Minimizing the environmental impacts of power generation

    b. Minimizing the environmental and land use impacts of building new transmission corridors to bring the power from where it is generated to where it is used

    c. Keeping down the cost of electricity charged to customers

    d. Ensuring a reliable source of power

    e. Generating power within BC rather than importing it from the US

    f. Meeting the goals of the new BC Energy Plan

    01 – Critically important
    02 – Important but not critical
    03 – Not very important
    VOLUNTEERED
    04 – Not at all important
    05 – Depends
    99 – DK/NA

18. (IF MORE THAN ONE IN Q.17 IS CRITICALLY IMPORTANT) Among the considerations you identified as critically important, which one do you think is the most important of all?
READ ITEMS FROM Q.17 RATED AS CRITICALLY IMPORTANT, IN SAME SEQUENCE – CODE ONE ONLY

    01 - Minimizing the environmental impacts of power generation
    02 - Minimizing the environmental and land use impacts of building new transmission corridors to bring the power from where it is generated to where it is used
    03 - Keeping down the cost of electricity charged to customers
    04 - Ensuring a reliable source of power
    05 - Generating power within BC rather than importing it from the US
    06 - Meeting the goals of the new BC Energy Plan
    VOLUNTEERD
    07 – All equally important
    08 - Depends
    98 – Other (SPECIFY _____)
    99 – DK/NA

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Commercial Questionnaire

19. The FortisBC Resource Plan projects a rising demand for electric power in the region over the next 20 years, and identifies several options for how to generate the required amount of power over this timeframe.

I will read you a list of options being considered. For each, please tell me whether you think this option should definitely be considered, likely be considered, likely not be considered or definitely not be considered for the new electrical power plan for the region.
READ AND ROTATE – ASK WHY QUESTION (Q.20) AFTER EACH ITEM IS READ

a. Development of small scale hydro-electric power projects on rivers in the region

b. Development of a single large hydro-electric power generating station located in the province
FOR a and b, READ ONLY IF ASKED WHAT HYDRO-ELECTRIC IS - Hydroelectricity is where the energy of moving water is converted to electric energy and conveyed along transmission lines to your home.

c. Development of new wind power stations in the region, using large scale windmills situated on "wind farms"
READ ONLY IF ASKED WHAT WIND FARMS ARE - A wind farm is a power plant that uses windmills or wind turbines to generate electricity.

d. Development of biomass energy plants, that can produce electricity through the combustion of dead trees killed by the Pine Beetle
READ ONLY IF ASKED WHAT BIOMASS ENERGY IS – Biomass energy is produced by the processing of organic materials such as wood, straw or manure.

e. Development of new power plants that use natural gas to produce electricity

f. Purchasing the required electricity from other utilities in the U.S through the wholesale market.

g. Purchasing the required electricity from other power producers in the province

01 – Definitely consider
02 – Likely consider
03 – Likely not consider
04 – Definitely not consider
VOLUNTEERED
05 – Depends
99 – DK/NA DO NOT ASK Q.20

20 Why do you say that?
SPECIFY

a. Development of small scale hydro-electric power projects on rivers in the region

b. Development of a single large hydro-electric power generating station located in the province

c. Development of new wind power stations in the region, using large scale windmills situated on "wind farms"

d. Development of biomass energy plants, that can produce electricity through the combustion of dead trees killed by the Pine Beetle

e. Development of new power plants that use natural gas to produce electricity

f. Purchasing the required electricity from other utilities in the U.S through the wholesale market.

g. Purchasing the required electricity from other power producers in the province

_____
99 – DK/NA

21. From what you know or have heard, how would you rate each of these electric power options in terms of its impact on the environment? Would you say that generating and supplying electricity to the region through [READ IN SEQUENCE] would have a major, moderate, minor or no impact on the environment?
READ IN SAME SEQUENCE AS IN Q.19

a. Small scale hydro-electric power projects

b. Large hydro-electric power generating stations
FOR a and b, READ ONLY IF ASKED WHAT HYDRO-ELECTRIC IS - Hydroelectricity is where the energy of moving water is converted to electric energy and conveyed along transmission lines to your home.

c. Wind power stations in the region, using large scale windmills situated on "wind farms"
READ ONLY IF ASKED WHAT WIND FARMS ARE - A wind farm is a power plant that uses windmills or wind turbines to generate electricity.

d. Biomass energy plants, using dead trees killed by the Pine Beetle
READ ONLY IF ASKED WHAT BIOMASS ENERGY IS – Biomass energy is produced by the processing of organic materials such as wood, straw or manure.

e. Power plants that use natural gas

f. Purchasing the required electricity from other utilities in the U.S

g. Purchasing the required electricity from other power producers in the province

01 - Major impact
02 - Moderate impact
03 - Minor impact
04 - No Impact
VOLUNTEERED
99 - DK/NA

22. You identified the following options as the ones that FortisBC should definitely consider in the new Resource Plan for the region's electricity supply [READ "DEFINITELY CONSIDER" OPTIONS FROM Q.19 IN SAME SEQUENCE (IN ABBREVIATED FORM)]

[This option/these options] may be more expensive to provide, compared with the current cost to supply electrical power. Would your organization definitely, likely, likely not or definitely not pay a higher price for the electricity you buy if this was required in order to pay for [this new source/these new sources] of electric power?

01 – Definitely
02 – Likely
03 – Likely not SKIP TO Q.24
04 – Definitely not SKIP TO Q.24
VOLUNTEERED
05 – Depends (e.g. on how much)
99 – DK/NA

23a. (IF DEFINITELY/LIKELY/DEPENDS/DK/NA IN Q.22). Would your organization be prepared to pay 20 percent more for electricity in order to help pay for the right type of new electric power in the region?

01 – Yes SKIP TO Q.24
02 – No
VOLUNTEERED
03 –Depends
99 – DK/NA

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23b. (IF NO/DEPENDS/DK/NA IN Q.23a) Would your organization be prepared to pay 10 percent more for electricity in order to help pay for the right type of new electric power in the region?

01 – Yes SKIP TO Q.24
02 – No
VOLUNTEERED
03 –Depends
99 – DK/NA

23c. (IF NO/DEPENDS/DK/NA IN Q.23b) Would your organization be prepared to pay 5 percent more for electricity in order to help pay for the right type of new electric power in the region?

01 – Yes
02 – No
VOLUNTEERED
03 –Depends
99 – DK/NA

24. Another way to address the electric power needs of the region is through energy conservation, which can be defined simply as making conscious decisions and actions to reduce ones use of energy, which might involve being more efficient or cutting back the amount of energy used.

Do you think energy conservation can play a major role, a moderate role, a minor role, or no role at all in ensuring the region has the supply of power it will need over the next 20 years?

01 - Major role
02 - Moderate role
03 - Minor role
04 – No role at all
VOLUNTEERED
99 - DK/NA

25. Do you think that individual consumers such as yourself can definitely, likely, likely not or definitely not make an important contribution to reducing the overall amount of electrical energy used in the region?

01 – Definitely
02 – Likely
03 – Likely not
04 – Definitely not
VOLUNTEERED
05 – Depends
99 – DK/NA

26. Are you interested in learning more about this Plan by FortisBC?

01 – Yes
02 – No SKIP TO Q.28
99 – DK/NA SKIP TO Q.28

27. (IF YES TO Q.26) What aspects of this Plan are you most interested in learning more about?
DO NOT READ – CODE ALL THAT APPLY

01 – Benefits and costs of options
02 – Cost implications
03 – Environmental implications
04 – Transmission issues
05 – Opportunities for public consultation/input
06 – How Plan fits with BC Energy Plan
98 – Other (SPECIFY _____)
99 – DK/NA

C. Customer Characteristics

To finish up, I would like to ask you a few questions about your organization for statistical purposes only. Please be assured that your answers will remain completely confidential.

28. What is your position with the organization?
DO NOT READ

01 – Administrator
02 – CFO/CEO/COO
03 – Director
04 – Director/Manager/Supervisor/VP of Operations
05 – Electrical Supervisor/Superintendent
06 – Electrical Specialist/Electrical Technician/Electrical Analyst
07 – Engineer
08 – Manager/Account Manager/Area Manager
09 – Owner
10 – Plant Manager
11 – President/Vice President
12 – Production Superintendent/Production Foreman
98 – Other (SPECIFY _____)
99 – DK/NA

29. What industry or sector would you categorize your organization?
READ ITEMS

01 – Church
02 – Education
03 – Healthcare / Medical Clinic / Hospital
04 – Lumber
05 – Oil & Gas
06 – Resort/golf club
07 – Small business
08 – Telecommunications
09 – Transportation / Logistics
VOLUNTEERED
98 – Other (SPECIFY _____)
99 – DK/NA

30. Number of locations in region

31. Number of employees in region

This completes the survey. In case my supervisor would like to verify that I conducted this interview, may I please have your first name?

First Name: _____

Thank you for your time and assistance with this survey.

IF REQUESTED – PROVIDE CONTACT NUMBER AT FortisBC

The FortisBC contact centre customer service number is 1-866-4FORTIS (1-866-436-7847). The contact centre is open 0700-1900hrs Monday – Friday.

END CALL

RECORD

37. Gender

01 - Male
02 – Female

Appendix C: Workshop Questionnaire (Part 1)

Workshop Questionnaire: Part 1

Research Project (08-6637)

Kelowna: February 18, 2008
Castlegar: February 20, 2008

Respondent: _____

PART 1:

BACKGROUND INFORMATION

Instructions

- You have 15 minutes to complete this section
- When you are done this section, please put your pencil down
- When everyone is ready, the facilitator will provide further instructions
- Please don't disturb your neighbours (Thank you!)

Part 1: Background Information

About You

1. Please write in your age

   _____ AGE

2. Please indicate your gender **[CHECK BOX]**

   ☐ 1 Male
   ☐ 2 Female

3. Please record your postal code

   _ _ _ _ _ _ _ _

4. Which of the following best describes your own present employment status? Are you... **[CHECK ONE BOX ONLY]**

   ☐ 1 Working full-time
   ☐ 2 Working part-time
   ☐ 3 Unemployed or looking for a job
   ☐ 4 Stay at home full-time
   ☐ 5 Student
   ☐ 6 Retired

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Workshop Questionnaire: Part 1

5. Do you currently own or rent your home? **[CHECK ONE BOX ONLY]**

- ☐ 1 Own
- ☐ 2 Rent

6. Which of the following best describes your home? **[CHECK ONE BOX ONLY]**

- ☐ 1 Single family dwelling
- ☐ 2 Townhome or duplex
- ☐ 3 Low-rise apartment building
- ☐ 4 High rise apartment building
- ☐ 5 Farm
- ☐ 6 Basement Suite

7. How many people, including yourself, currently live in your household?

_____

Energy and Electricity Issues

8. What issue do you think is the most important for the South Central region of BC, with respect to the generation and use of electrical energy?

[CHECK ALL BOXES THAT APPLY]

- ☐ 1 Price/cost of electricity
- ☐ 2 Supply of electricity/having enough/running out
- ☐ 3 Power outages/blackouts
- ☐ 4 Alternative energy sources (wind, solar, biofuels)
- ☐ 5 Environmental impacts of energy production
- ☐ 6 Environmental impacts of energy consumption
- ☐ 7 Need to conserve/reduce consumption
- ☐ 8 New B.C. Energy Plan
- ☐ 98 Other (SPECIFY _____)
- ☐ 97 None

9. What are the main sources or means by which electricity is generated to supply the needs of homes and businesses in your region today?

[CHECK ALL BOXES THAT APPLY]

- ☐ 1 Oil
- ☐ 2 Natural Gas
- ☐ 3 Hydro-electric power/Dams/Water power (power generated from dams on rivers and streams)
- ☐ 4 Nuclear Power
- ☐ 5 Coal
- ☐ 6 Wind energy/windmills
- ☐ 7 Solar energy
- ☐ 8 Electricity imported from the U.S.
- ☐ 98 Other (SPECIFY _____)
- ☐ 99 Don't Know

Workshop Questionnaire: Part 1

10. As far as you know, does the generation of electric power by the methods in Column A cause major, moderate, minor or no damage to the environment in the community in which you live.....

[CIRCLE ONE NUMBER IN EACH COLUMN FOR EACH ELECTRICITY SOURCE TYPE]

COLUMN A	Major Impact	Moderate Impact	Minor Impact	No Impact	Don't Know
Oil	1	2	3	4	5
Natural Gas	1	2	3	4	5
Hydro-electric power/Dams/Water power	1	2	3	4	5
Nuclear Power	1	2	3	4	5
Coal	1	2	3	4	5
Wind energy/windmills	1	2	3	4	5
Solar energy	1	2	3	4	5
Electricity imported from the U.S.	1	2	3	4	5

11. From what you know or have heard, do you think your region currently has more than enough, as much as is needed, or less than is needed, to meet the region's demand for electrical power over the next two to five years?

[CHECK ONE BOX ONLY]

- ☐ 1 More than enough
- ☐ 2 As much as needed
- ☐ 3 Less than needed
- ☐ 99 Don't Know

12. And what about the longer term? Do you think your region will have more than enough, as much as needed, or less than is needed to meet the electrical power demand 20 years from now?

[CHECK ONE BOX ONLY]

- ☐ 1 More than enough
- ☐ 2 As much as needed
- ☐ 3 Less than needed
- ☐ 99 Don't Know

13. Do you feel the price you currently pay for your household electricity service is:

[CHECK ONE BOX ONLY]

- ☐ 1 Too low
- ☐ 2 About right
- ☐ 3 Too high

14. Does the current size of your household electric or hydro bill make a noticeable, small or no impact on your household finances each month?

[CHECK ONE BOX ONLY]

- ☐ 1 Noticeable impact
- ☐ 2 Small impact
- ☐ 3 No impact

Workshop Questionnaire: Part 1

15. FortisBC, your regional electricity supplier, is developing a comprehensive Resource Plan for meeting your region's electric power needs over the next 20 years. This plan identifies the anticipated growth and need for electric power to the year 2027, and identifies different options for meeting this demand that can best meet its objective of ensuring safe, cost-effective and reliable energy for its customers.

    There are number of factors to be considered in identifying the best options for providing long term power for the region. Do you think each of the following considerations in Column A is critically important, important but not critical, or not very important in deciding which electrical supply options should be selected?

[CIRCLE ONE NUMBER IN EACH COLUMN FOR EACH ITEM IN COLUMN A]

	COLUMN A	Critically Important	Important but Not Critical	Not Very Important	Not at all Important
A	Minimizing the environmental impacts of power generation	1	2	3	4
B	Minimizing the environmental and land use impacts of building new transmission corridors to bring the power from where it is generated to where it is used	1	2	3	4
C	Keeping down the cost of electricity charged to customers	1	2	3	4
D	Ensuring a reliable source of power	1	2	3	4
E	Generating power within BC rather than importing it from the U.S	1	2	3	4
F	Meeting the goals of the new BC Energy Plan	1	2	3	4

16. Among the considerations you identified as critically important, which **ONE** do you think is the most important of all?

- ☐ 1 Minimizing the environmental impacts of power generation
- ☐ 2 Minimizing the environmental and land use impacts of building new transmission corridors to bring the power from where it is generated to where it is used
- ☐ 3 Keeping down the cost of electricity charged to customers
- ☐ 4 Ensuring a reliable source of power
- ☐ 5 Generating power within BC rather than importing it from the U.S
- ☐ 6 Meeting the goals of the new BC Energy Plan

Why do you say that?

_____

_____

When you are done, please put your pencil down

and wait for the facilitator to provide further instructions.

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Appendix D: Workshop Questionnaire (Part 2)

Workshop Questionnaire: Part 2

PART 2:
REACTION TO PRESENTATION OF
ELECTRICITY GENERATION OPTIONS

Instructions

- You have 15 minutes to complete this section
- When you are done this section, please turn your survey over
- When everyone is ready, the facilitator will provide further instructions
- Please don't disturb your neighbours (Thank you!)

Part 2: Reaction to Presentation of Electricity Generation Options

1. The FortisBC Resource Plan projects a rising demand for electric power in the region over the next 20 years. The presentation by FortisBC outlined some different options for generating this additional electrical power.

   For each type of electricity generation option in Column A, please indicate whether you think this option should definitely be considered, should be considered, likely not be considered or definitely not be considered for the new electrical power plan for the region by circling the number in the corresponding column.

   Then, for any options which you identified as 'Definitely Consider', please provide the reason **why** in Column B.

[CIRCLE ONE NUMBER ONLY FOR EACH OPTION IN COLUMN A]

	COLUMN A	Definitely Consider	Should Consider	Should Not be Considered	Definitely Not Consider	COLUMN B: REASON FOR SELECTING AS 'DEFINITELY CONSIDER'
A	Development of small-scale hydro-electric dams on waterways within the FortisBC territory	1	2	3	4	
B	Development of a single large hydro-electric dam outside FortisBC's territory	1	2	3	4	
C	Development of new wind power stations within FortisBC's territory, using large-scale windmills situated on "wind farms"	1	2	3	4	
D	Development of bio-mass wood waste plants which can produce electricity through burning dead trees killed by the Pine Beetle	1	2	3	4	
E	Development of new power plants that use natural gas to produce electricity	1	2	3	4	
F	Buying more electricity from the wholesale energy market, which is supplied by U.S., Alberta and other B.C. power companies	1	2	3	4	
G	Purchasing the required electricity from other power producers in B.C.	1	2	3	4	

2. From what you know or have heard, how would you rate each of these electric power options in terms of its impact on the environment? Would you say that generating and supplying electricity to the region through each of the options in Column A would have a major, moderate, minor or no impact on the environment?

   [CIRCLE ONE NUMBER ONLY FOR EACH OPTION]

	COLUMN A	Major Impact	Moderate Impact	Minor Impact	No Impact
A	Development of small-scale hydro-electric dams on waterways within the FortisBC territory	1	2	3	4
B	Development of a single large hydro-electric dam outside FortisBC's territory	1	2	3	4
C	Development of new wind power stations within FortisBC's territory, using large-scale windmills situated on "wind farms"	1	2	3	4
D	Development of bio-mass wood waste plants which can produce electricity through burning dead trees killed by the Pine Beetle	1	2	3	4
E	Development of new power plants that use natural gas to produce electricity	1	2	3	4
F	Buying more electricity from the wholesale energy market, which is supplied by U.S., Alberta and other B.C. power companies	1	2	3	4
G	Purchasing the required electricity from other power producers in B.C.	1	2	3	4

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FORTISBC

Workshop Questionnaire: Part 2

3. How important is it to you personally that FortisBC pursues each of the following goals of the BC Energy Plan?

[CIRCLE ONE NUMBER ONLY FOR EACH STATEMENT]

		Very important	Somewhat important	Somewhat unimportant	Not at all important
A	Climate change/plan to address climate change	4	3	2	1
B	Targets to reduce greenhouse gas emissions	4	3	2	1
C	Reduce environmental impacts of energy	4	3	2	1
D	Develop new sources of power	4	3	2	1
E	Make your region more energy self-sufficient	4	3	2	1
F	Develop clean sources of energy	4	3	2	1
G	Reduce environmental impacts of energy generation	4	3	2	1
H	Ensure your region has adequate long-term supply of power	4	3	2	1
I	Improve energy efficiency/standards	4	3	2	1
J	Promote alternative energy sources	4	3	2	1

4. Some of the options may be more expensive to provide, compared with the current cost to supply electrical power. Would you definitely, likely, likely not or definitely not pay a higher price for the electricity you buy at home if this was required in order to pay for new sources of electric power?

[CHECK ONE BOX ONLY]

- ☐ 1 Definitely would pay a higher price
- ☐ 2 Would likely pay a higher price
- ☐ 3 Would not likely pay a higher price
- ☐ 4 Would definitely not pay a higher price

5. Another way to address the electric power needs of the region is through energy conservation, which can be defined simply as making conscious decisions and actions to reduce your use of energy, which might involve being more efficient or cutting back the amount of energy used.

Do you think energy conservation can play a major role, a moderate role, a minor role, or no role at all in ensuring the region has the supply of power it will need over the next 20 years?

[CHECK ONE BOX ONLY]

- ☐ 1 Major role
- ☐ 2 Moderate role
- ☐ 3 Minor role
- ☐ 4 No role at all

6. Do you think that individual consumers such as yourself can definitely, likely, likely not or definitely not make an important contribution to reducing the overall amount of electrical energy used in the region?

[CHECK ONE BOX ONLY]

- ☐ 1 Definitely could reduce overall energy use
- ☐ 2 Likely could reduce overall energy use
- ☐ 3 Would not likely reduce overall energy use
- ☐ 4 Would definitely not reduce overall energy use

Workshop Questionnaire: Part 2

7. Now that we have reviewed the options that FortisBC has identified as potential sources of electrical energy for your region, please rate how well you think each of the options answers each of the factors considered in Part 1, Question 15.

Please rate how well each of the energy generation options addresses each of the factors on the following scale:

1 = Definitely addresses this concern

2 = Likely addresses this concern

3 = Probably does not address this concern

4 = Definitely does not address this concern

[CIRCLE ONE NUMBER ONLY FOR EACH STATEMENT]

	Buying more electricity from the wholesale energy market, which is supplied by U.S., Alberta and other B.C. power companies	**Definitely Addresses this Concern**	**Likely Addresses This Concern**	**Probably Does Not Address This Concern**	**Definitely Does Not Address This Concern**
A	Minimizing the environmental impacts of power generation	1	2	3	4
B	Minimizing the environmental and land use impacts of building new transmission corridors to bring the power from where it is generated to where it is used	1	2	3	4
C	Keeping down the cost of electricity charged to customers	1	2	3	4
D	Ensuring a reliable source of power	1	2	3	4
E	Generating power within BC rather than importing it from the U.S	1	2	3	4
F	Meeting the goals of the new BC Energy Plan	1	2	3	4

	Development of a Combined Cycle Gas Turbine plant that would generate enough electricity to meet FortisBC's projected customer demand until 2020	**Definitely Addresses this Concern**	**Likely Addresses This Concern**	**Probably Does Not Address This Concern**	**Definitely Does Not Address This Concern**
A	Minimizing the environmental impacts of power generation	1	2	3	4
B	Minimizing the environmental and land use impacts of building new transmission corridors to bring the power from where it is generated to where it is used	1	2	3	4
C	Keeping down the cost of electricity charged to customers	1	2	3	4
D	Ensuring a reliable source of power	1	2	3	4
E	Generating power within BC rather than importing it from the U.S	1	2	3	4
F	Meeting the goals of the new BC Energy Plan	1	2	3	4

	Development of large hydro-electric dams outside the FortisBC territory that would provide additional electricity at peak demand times to supplement electricity purchases from the wholesale energy market	**Definitely Addresses this Concern**	**Likely Addresses This Concern**	**Probably Does Not Address This Concern**	**Definitely Does Not Address This Concern**
A	Minimizing the environmental impacts of power generation	1	2	3	4
B	Minimizing the environmental and land use impacts of building new transmission corridors to bring the power from where it is generated to where it is used	1	2	3	4
C	Keeping down the cost of electricity charged to customers	1	2	3	4
D	Ensuring a reliable source of power	1	2	3	4
E	Generating power within BC rather than importing it from the U.S	1	2	3	4
F	Meeting the goals of the new BC Energy Plan	1	2	3	4

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Workshop Questionnaire: Part 2

	A combination of bio-mass wood waste plants, a large wind farm, and small hydro-electric dams on waterways within the FortisBC territory to supplement electricity purchases from the wholesale energy market	Definitely Addresses this Concern	Likely Addresses This Concern	Probably Does Not Address This Concern	Definitely Does Not Address This Concern
A	Minimizing the environmental impacts of power generation	1	2	3	4
B	Minimizing the environmental and land use impacts of building new transmission corridors to bring the power from where it is generated to where it is used	1	2	3	4
C	Keeping down the cost of electricity charged to customers	1	2	3	4
D	Ensuring a reliable source of power	1	2	3	4
E	Generating power within BC rather than importing it from the U.S	1	2	3	4
F	Meeting the goals of the new BC Energy Plan	1	2	3	4

	A combination of a Simple Cycle Gas Turbine plant, a Combined Cycle Gas Turbine plant and a large-scale Wind Farm	Definitely Addresses this Concern	Likely Addresses This Concern	Probably Does Not Address This Concern	Definitely Does Not Address This Concern
A	Minimizing the environmental impacts of power generation	1	2	3	4
B	Minimizing the environmental and land use impacts of building new transmission corridors to bring the power from where it is generated to where it is used	1	2	3	4
C	Keeping down the cost of electricity charged to customers	1	2	3	4
D	Ensuring a reliable source of power	1	2	3	4
E	Generating power within BC rather than importing it from the U.S	1	2	3	4
F	Meeting the goals of the new BC Energy Plan	1	2	3	4

	A combination of a Simple Cycle Gas Turbine plant, a Combined Cycle Gas Turbine plant and small hydro-electric dams on waterways within the FortisBC territory	Definitely Addresses this Concern	Likely Addresses This Concern	Probably Does Not Address This Concern	Definitely Does Not Address This Concern
A	Minimizing the environmental impacts of power generation	1	2	3	4
B	Minimizing the environmental and land use impacts of building new transmission corridors to bring the power from where it is generated to where it is used	1	2	3	4
C	Keeping down the cost of electricity charged to customers	1	2	3	4
D	Ensuring a reliable source of power	1	2	3	4
E	Generating power within BC rather than importing it from the U.S	1	2	3	4
F	Meeting the goals of the new BC Energy Plan	1	2	3	4

	Purchasing the required electricity from other power producers in B.C.	Definitely Addresses this Concern	Likely Addresses This Concern	Probably Does Not Address This Concern	Definitely Does Not Address This Concern
A	Minimizing the environmental impacts of power generation	1	2	3	4
B	Minimizing the environmental and land use impacts of building new transmission corridors to bring the power from where it is generated to where it is used	1	2	3	4
C	Keeping down the cost of electricity charged to customers	1	2	3	4
D	Ensuring a reliable source of power	1	2	3	4
E	Generating power within BC rather than importing it from the U.S	1	2	3	4
F	Meeting the goals of the new BC Energy Plan	1	2	3	4

	Development of large hydro-electric dams in areas outside FortisBC's territory that would generate enough electricity to meet FortisBC's projected customer demand	Definitely Addresses this Concern	Likely Addresses This Concern	Probably Does Not Address This Concern	Definitely Does Not Address This Concern
A	Minimizing the environmental impacts of power generation	1	2	3	4
B	Minimizing the environmental and land use impacts of building new transmission corridors to bring the power from where it is generated to where it is used	1	2	3	4
C	Keeping down the cost of electricity charged to customers	1	2	3	4
D	Ensuring a reliable source of power	1	2	3	4
E	Generating power within BC rather than importing it from the U.S	1	2	3	4
F	Meeting the goals of the new BC Energy Plan	1	2	3	4

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8. Many of the options included in Question 7 would require new transmission infrastructure such as substations and transmission towers to relay the electricity from the place it is generated to the FortisBC service region. The expected transmission impact includes both the financial cost of building the transmission lines and the environmental impact.

   FortisBC's assessment of the transmission impact of each option is shown in Column B.

   Considering the assessment you gave for each option in Q.7 and the expected transmission impact shown in Column B, please **RANK** the options in Column C, where a rank of **1 would be your most preferred** option and **8 would be your least preferred option**.

	COLUMN A: Energy Generation Option	COLUMN B: Expected Transmission Impact	COLUMN C: Your Rank (1 to 8)
A	Buying more electricity from the wholesale energy market, which is supplied by U.S., Alberta and other B.C. power companies	**Medium to High**	
B	Development of a Combined Cycle Gas Turbine plant that would generate enough electricity to meet FortisBC's projected customer demand until 2020	**Very Low to Low**	
C	Development of large hydro-electric dams outside the FortisBC territory that would provide additional electricity at peak demand times to supplement electricity purchases from the wholesale energy market	**Medium to High**	
D	A combination of bio-mass wood waste plants, a large wind farm, and small hydro-electric dams on waterways within the FortisBC territory to supplement electricity purchases from the wholesale energy market	**High**	
E	A combination of a Simple Cycle Gas Turbine plant, a Combined Cycle Gas Turbine plant and a large-scale Wind Farm	**Medium to High**	
F	A combination of a Simple Cycle Gas Turbine plant, a Combined Cycle Gas Turbine plant and small hydro-electric dams on waterways within the FortisBC territory	**Low to Medium**	
G	Purchasing the required electricity from other power producers in B.C.	**Medium to High**	
H	Development of large hydro-electric dams in areas outside FortisBC's territory that would generate enough electricity to meet FortisBC's projected customer demand	**High**	

8. Of all the options presented tonight, which **ONE** is your preferred option?

   [CHECK ONE BOX ONLY]

- ☐ 1 Buying more electricity from the wholesale energy market, which is supplied by U.S., Alberta and other B.C. power companies
- ☐ 2 Development of a Combined Cycle Gas Turbine plant that would generate enough electricity to meet FortisBC's projected customer demand until 2020
- ☐ 3 Development of large hydro-electric dams outside the FortisBC territory that would provide additional electricity at peak demand times to supplement electricity purchases from the wholesale energy market
- ☐ 4 Combination of bio-mass wood waste plants, a large wind farm, and small hydro-electric dams to supplement electricity purchases from the wholesale energy market
- ☐ 5 A combination of a Simple Cycle Gas Turbine plant, a Combined Cycle Gas Turbine plant and a large-scale Wind Farm
- ☐ 6 A combination of a Simple Cycle Gas Turbine plant, a Combined Cycle Gas Turbine plant and small hydro-electric dams on waterways within the FortisBC territory
- ☐ 7 Purchasing the required electricity from other power producers in B.C.
- ☐ 8 Development of large hydro-electric dams in areas outside FortisBC's territory that would generate enough electricity to meet FortisBC's projected customer demand

Why is this one your preferred option?

_____

_____

10. What problems or concerns, if any, do you have with your preferred option?

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Workshop Questionnaire: Part 2

11a. Was there anything in the presentation that was confusing or difficult for you to understand?

- ☐ 1 Yes
- ☐ 2 No

11b. **IF YES**, what was confusing or difficult to understand?

_____

_____

_____

12. What additional comments or suggestions do you have?

_____

_____

_____

_____

_____

_____

When you are done, please turn your survey over and wait for the facilitator to provide further instructions.

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Western Electricity Coordinating Council

10-Year Coordinated Plan Summary

Planning and Operation for Electric System Reliability

July 2006

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Introduction

Western Electricity Coordinating Council (WECC) is one of 10 electric reliability councils in North America, encompassing a geographic area equivalent to over half the United States. WECC is responsible for promoting electric system reliability, supporting competitive electricity markets, assuring access to the transmission grid, and providing a forum for coordinating the operating and planning activities of the western interconnected power grid. WECC's members, representing all segments of the electric industry, provide electricity to 71 million people in 14 western states, two Canadian provinces, and portions of one Mexican state.

Since August 1967, WECC and its predecessor organizations have provided the coordination that is essential for operating and planning a reliable and adequate electric power system for the western part of the continental United States, Canada, and Mexico. In addition to promoting a reliable electric power system in the Western Interconnection, WECC supports efficient competitive power markets, assures open and non-discriminatory transmission access among members, and provides a forum for resolving transmission access disputes.

Membership in WECC is voluntary and open to any organization having an interest in the reliability of interconnected system operation or coordinated planning. WECC's 180 members are comprised of investor-owned utilities, municipal utilities, public power systems, independent power producers/qualified facilities, marketers, independent system operators/power pools, federal agencies, state and provincial energy commissions, end users of electricity, and other organizations.

The Council provides the forum for its members to enhance communication, coordination, and cooperation – all vital ingredients in planning and operating a reliable interconnected electric system.

The WECC region encompasses a vast area of nearly 1.8 million square miles. It is the largest and most diverse of the ten regional councils of the North American Electric Reliability Council (NERC). WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of the 14 western states in between. The region is naturally divided into four major areas – Northwest, Rocky Mountain, Arizona-New Mexico-Southern Nevada, and California-Mexico, which reflect varying, and sometimes extreme geographic and climatic conditions. Transmission lines span long distances from the verdant Pacific Northwest with abundant hydroelectric resources to the arid Southwest with large coal-fired and nuclear resources.

Due to the vastness and diverse characteristics of the region, WECC's members are faced with unique and challenging problems in coordinating day-to-day interconnected system operation and the long-range planning needed to provide reliable and affordable electric service to approximately 71 million people in WECC's service territory.

This annual report provides information concerning the reliability and adequacy of the planned WECC interconnected bulk power system, and includes:

- An assessment of bulk power system reliability;
- Uncertainties and the potential effects;
- Historical load and resource information;
- Projected peak demand and energy load growth; and
- Planned generation and transmission facilities.

The ten-year (2006-2015) coordinated plans of the WECC organizations are as of January 1, 2006.

WECC Members

AES1	–	Advanced Energy Solutions
ADOE	–	Alberta Department of Energy
AESO	–	Alberta Electric System Operator
AEUB	–	Alberta Energy and Utilities Board
AESC	–	Allegheny Energy Supply Company, LLC
ALTA	–	AltaLink L.P.
AWEA	–	American Wind Energy Association
WPE	–	Aquila Networks-WPC
ACC	–	Arizona Corporation Commission
AEPC	–	Arizona Electric Power Cooperative, Inc.
APA	–	Arizona Power Authority
APS	–	Arizona Public Service Company
ATCO	–	ATCO Electric Ltd.
AUR	–	Auriga Corporation
APX	–	Automated Power Exchange, Inc.
AVA	–	Avista Corp.
BEPC	–	Basin Electric Power Cooperative
BMI	–	Battelle Memorial Institute
B&V	–	Black & Veatch Corporation
BHP	–	Black Hills Power
BPAP	–	Bonneville Power Administration – Power Business Line
BPAT	–	Bonneville Power Administration – Transmission Business Line
BPAE	–	BP Alternative Energy
BCHA	–	British Columbia Hydro and Power Authority
BCME	–	British Columbia Ministry of Energy & Mines
BCTC	–	British Columbia Transmission Corporation
BCUC	–	British Columbia Utilities Commission
BURB	–	Burbank Water and Power
CBC	–	California British Columbia Transmission Company, LLC
CDWR	–	California Department of Water Resources
CEOB	–	California Electricity Oversight Board
CEC	–	California Energy Commission
CFBF	–	California Farm Bureau Federation
CISO	–	California Independent System Operator
CORA	–	California Office of Ratepayer Advocates
CPUC	–	California Public Utilities Commission
CALP	–	Calpine Corporation
CES	–	Cambridge Energy Solutions
CRGL	–	Cargill Power Markets, LLC
CEOE	–	CE Obsidian Energy
CAWC	–	Central Arizona Water Conservation District
CINE	–	Cinergy Services, Inc.
CEI	–	Citigroup Energy Inc.
HHWP	–	City and County of San Francisco – Hetch Hetchy Water & Power
ANHM	–	City of Anaheim
GLEN	–	City of Glendale Public Service Department
RDNG	–	City of Redding
RVSD	–	City of Riverside
COPC	–	Colorado Public Utilities Commission
CSU	–	Colorado Springs Utilities
CFE	–	Comision Federal de Electricidad
COMP	–	Compusharp Inc.
CCG	–	Constellation Energy Commodities Group, Inc.
DGT	–	Deseret Generation & Transmission Co-operative
DENA	–	Duke Energy North America, LLC
ECON	–	Economic Insight
EMMT	–	Edison Mission Marketing & Trading, Inc.
EQI	–	EleQuant, Inc.
EPE	–	El Paso Electric Company
ECI	–	Electrical Consultants, Inc.
ENW	–	Energy Northwest
ESL	–	Energy Strategies LLC
ENMX	–	ENMAX Corporation
EMC	–	EPCOR Merchant and Capital L.P.
EMCU	–	EPCOR Merchant and Capital (US) Inc.
EWEB	–	Eugene Water & Electric Board
FARM	–	Farmington Electric Utility System
FBC	–	FortisBC
FPLE	–	FPL Energy LLC
GEO	–	Geo-Energy Partners-1983 Ltd.
GBPP	–	Gila Bend Power Partners, LLC
PGR	–	Gila River Power, L.P.
GBT	–	Great Basin Transmission, LLC
HGC	–	Harquahala Generating Company, LLC
HESI	–	Henwood Energy Services, Inc.
HPLP	–	Hunt Power, L.P.
IPC	–	Idaho Power Company
IPUC	–	Idaho Public Utilities Commission
IID	–	Imperial Irrigation District
KEMA	–	KEMA Inc.
LCG	–	LCG Consulting
LAC	–	Los Alamos County
LDWP	–	Los Angeles Department of Water and Power
MLCI	–	Merrill Lynch Commodities, Inc.
MWD	–	Metropolitan Water District of Southern California
MTI	–	Micron Technology Inc.
MIR	–	Mirant Americas, Inc.
MID	–	Modesto Irrigation District
MATL	–	Montana Alberta Tie Ltd.
MDEQ	–	Montana Department of Environmental Quality
MPSC	–	Montana Public Service Commission
MWEC	–	Morenci Water & Electric Company
NGU	–	National Grid USA Service Company, Inc.
NREL	–	National Renewable Energy Laboratory
NCI	–	Navigant Consulting, Inc.
NVOE	–	Nevada State Office of Energy
NMPRC	–	New Mexico Public Regulation Commission
NTD	–	New Transmission Development Company [A Trans-Elect Company]
NAPG	–	North American Power Group, Ltd.
NCPA	–	Northern California Power Agency
NPCC	–	Northwest Power and Conservation Council
NWMT	–	NorthWestern Energy
NRG	–	NRG Power Marketing, Inc.
OCES	–	Oak Creek Energy Systems, Inc.
OOE	–	Oregon Department of Energy
OPUC	–	Oregon Public Utility Commission
PG&E	–	Pacific Gas and Electric Company
PNWER	–	Pacific NorthWest Economic Region
PAC	–	PacifiCorp
PACM	–	PacifiCorp – Merchant Function
PASA	–	Pasadena, City of
PBEC	–	Peabody Energy Corporation
PRPA	–	Platte River Power Authority
PGE	–	Portland General Electric Company
PWX	–	Powerex
PPLE	–	PPL EnergyPlus, LLC
PPLM	–	PPL Montana, LLC
PPM	–	PPM Energy, Inc.
PRAX	–	Praxair, Inc.
PSC	–	Public Service Company of Colorado
PNM	–	Public Service Company of New Mexico
NPUC	–	Public Utilities Commission of Nevada
CHPD	–	Public Utility District No. 1 of Chelan County
DOPD	–	Public Utility District No. 1 of Douglas County
GCPD	–	Public Utility District No. 2 of Grant County
PSE	–	Puget Sound Energy
REI	–	Reliant Energy, Inc.
RES	–	RES America Developments, Inc.
RLE	–	Ridgeline Energy, LLC
RVE	–	Roseville Electric
SMUD	–	Sacramento Municipal Utility District
SRP	–	Salt River Project

WECC Members (continued)

SDGE – San Diego Gas & Electric Company
SME – Saracen Merchant Energy LP
SBP – Sea Breeze Pacific Regional Transmission Systems, Inc.
SCL – Seattle City Light
SPGI – Siemens Power Generation, Inc.
SER – Sempra Generation
SETC – Sempra Energy Trading Corp.
STGP – Shell Trading
SPR – Sierra Pacific Resources Transmission
SNCL – Silicon Valley Power – City of Santa Clara
SNPD – Snohomish County Public Utility District No. 1
SCE – Southern California Edison Company
SMGT – Southern Montana Electric Generation & Transmission Cooperative, Inc.
SWTC – Southwest Transmission Cooperative, Inc.
SWPG – Southwestern Power Group II, LLC
SUEZ – SUEZ Energy Marketing NA, Inc.
SC2G – SWRTA Class 2 Group
TPWR – Tacoma Power
TNSK – Tenaska
TNP – Texas-New Mexico Power Company
AES – The AES Corporation
BOE – The Boeing Company
TAUC – TransAlta Utilities Corporation
TCP – TransCanada Energy Ltd.
TANC – Transmission Agency of Northern California
TSGT – Tri-State Generation and Transmission Association, Inc.
TSMD – Tri-State Generation and Transmission Association, Inc.
TEP – Tucson Electric Power Company
TIDC – Turlock Irrigation District
USBR – U.S. Department of Interior, - Bureau of Reclamation
  USDO – (Denver Office)
  USGP – (Great Plains)
  USLC – (Lower Colorado)
  USMP – (Mid-Pacific)
  USPN – (Pacific Northwest)
  USUC – (Upper Colorado)
UAMP – Utah Associated Municipal Power Systems
UCCS – Utah Committee of Consumer Services
DPU – Utah Division of Public Utilities
UEO – Utah Energy Office
UMPA – Utah Municipal Power Agency
UPSC – Utah Public Service Commission
USE – Utility System Efficiencies, Inc.
VEA – Valley Electric Association, Inc.
OTED – Washington State Office of Trade & Economic Development
WUTC – Washington Utilities and Transportation Commission
WECI – Wellhead Electric Company, Inc.
WAPA – Western Area Power Administration
  WAHQ – (Golden, Colorado)
  WACM – (Loveland, Colorado)
  WALC – (Phoenix, Arizona)
  WASN – (Sacramento, California)
  WAUC – (Salt Lake City, Utah)
  WAUW – (Billings, Montana)
WND – Western Wind Energy Corporation
WLB – Westmoreland Coal Company
WEMT – Williams Power Company, Inc.
WIA – Wyoming Infrastructure Authority
WPSC – Wyoming Public Service Commission

Coordination to Promote System Reliability

Coordination is a vital part of daily electric system operation and is the key to the development of improved operating procedures and system planning criteria for promoting system reliability.

Prior to the formation of the Council, various operating and planning groups were organized to provide coordination for the interconnected utilities and pools within the western United States. The groups also provided a forum for day-to-day communication, which resulted in various practices and agreements being adopted by the utilities to enhance the adequacy and reliability of the interconnected bulk electric system.

During the planning process associated with the interconnections between the Northwest and California (Pacific Interties), it was apparent that the bulk electric systems in the western United States and parts of Canada would evolve into a highly integrated interconnected system. Recognizing the many benefits of interconnected system operation, executives representing the western utilities and agencies operating the bulk electric systems met on March 20, 1967, and agreed that a need existed for regional coordination with a broader scope. As a result, Western Systems Coordinating Council (WSCC) was established in August 1967.

On April 18, 2002, WSCC, the Southwest Regional Transmission Association (SWRTA), and Western Regional Transmission Association (WRTA) merged to form the Western Electricity Coordinating Council (WECC). As a result of the merger, WECC has acquired an expanded role which includes supporting efficient competitive power markets, assuring open and non-discriminatory transmission access among members, and providing a forum for resolving transmission access disputes.

WECC also continues to focus its efforts on promoting the reliability of the interconnected bulk electric system. Criteria have been developed and adopted for use by the members for day-to-day operation and system planning. The Council annually compiles and analyzes information pertaining to projected load growth, and new generation and transmission facilities. These and other Council activities are a direct result of the dedicated efforts of the members' personnel and WECC's staff to promote reliability.

The organizational structure of WECC consists of a Board of Directors, five Board Committees, three standing committees (Operating, Planning Coordination, and Market Interface), and numerous subcommittees and work groups.

Approximately 700 member organization executives, engineers, and other representatives devote time and expertise to the various activities of these committees. The committees provide a ready and effective means for developing regional planning and operating criteria, coordinating future plans, compiling regional data banks for use by the members and the Council in conducting technical studies, and for assessing and coordinating operating procedures and solutions to regional problems.

WECC's members include 180 major transmission utilities, transmission dependent utilities, independent power producers, marketers, power exchanges, end users of electricity, state and provincial regulatory agencies, and other organizations that have an interest in system operations and planning. Members of WECC have access to all of the information and data compiled by WECC, including computer models used to study the interconnected system, WECC computer programs for system analysis, WECC transmission maps, transfer capability data, member planning criteria, North American Electric Reliability Council (NERC) and WECC planning and operating criteria and policies, and WECC studies and surveys that evaluate system performance relative to WECC and NERC criteria and policies.

As the electric industry continues to undergo unprecedented change, WECC faces increasing challenges in maintaining interconnected electric system reliability. WECC has taken a number of proactive steps to position itself for the future and to implement an open process in which all interested parties may participate. An evaluation period for a Reliability Management System (RMS) was begun in 1998 and data were collected regarding criteria vital to maintaining electric system reliability. The RMS is North America's first voluntary program that assesses sanctions for noncompliance. The members approved moving ahead with RMS at the annual meeting in December 1998 and WECC's predecessor WSCC received a Declaratory Order from FERC and a Business Review letter from the Department of Justice in early 1999. The Declaratory Order and Business Review letter were both necessary elements enabling the members to sign the RMS agreements and proceed with final implementation of the program. An RMS signing ceremony was held on June 18, 1999 and the RMS program was officially implemented on September 1, 1999. In an increasingly competitive environment, RMS is promoting a level of electric reliability upon which customers have come to rely.

Board of Directors

As a result of the merger, WECC was formed with a superior governance structure over that which existed previously. The WECC Board consists of twenty-seven Director positions, including twenty Member Class Directors and seven Non-Affiliated Directors.

The Board of Directors is responsible for directing and coordinating the activities necessary to accomplish the purpose and goals of WECC. The WECC chief executive officer is responsible for conducting the day -to-day business affairs of the Council and for managing WECC's activities, including supervising WECC's staff.

The WECC Directors have positioned WECC to be proactive in addressing the challenges that arise from industry restructuring and a more competitive business environment.

WECC is continually enhancing its communication efforts regarding how the organization is responding to change. Examples include:

- An interactive Website allowing users to access publications, news releases, and other pertinent information; and
- Implementation of an open public process for the development and approval of reliability standards.

Operating Committee

The Operating Committee (OC) is responsible for proactively addressing operational issues affected by industry restructuring, and successfully integrating new policies and reliability criteria into the operation of the Western Interconnection.

WECC's first independent system operator, the California ISO (CISO) began operation as a control area in April 1998. The CISO control center subsumed control area operations of several WECC members and is home to the California-Mexico Reliability Coordinator.

In 1999 a task force was formed to evaluate the NERC Transaction Management System (TMS) Proposal and make recommendations regarding WECC's participation to the WECC Board of Directors. The TMS program is designed to manage interchange scheduling through the use of electronic tagging. On April 18, 2000, WECC implemented the NERC electronic tagging procedure.

The Compliance Monitoring and Operating Practices Subcommittee (CMOPS) implemented the Compliance Monitoring Program in 1995. Each year, 15 or more member systems are reviewed by teams of peers from other WECC members. The system being reviewed, called the Host System, explains how they have implemented WECC and NERC policies and criteria. Neighboring systems provide information to the review team regarding operating issues that they may have with the system being reviewed. The review team then provides a written report describing the review and containing conclusions and recommendations for improvement. The recommendations are maintained in a log and tracked until they are resolved. This program has proven to be very beneficial to all concerned, providing a forum for exchanging ideas about reliable operation of the bulk electric system. Control areas, being the entities primarily responsible for system reliability, are reviewed every three years. Fourteen control areas were reviewed in 2004.

Planning Coordination Committee

The Planning Coordination Committee (PCC) recommends system planning criteria, compiles and disseminates information pertaining to planned generation and transmission facilities, and performs studies to assess reliability of the WECC interconnected system.

WECC's compliance with the new NERC Planning Standards and Guides was a focus of the PCC during the past few years. A

comprehensive review of the Transmission System Planning portion of the Council's Reliability Criteria was completed by the Reliability Subcommittee and by the Board of Directors in 2002.

The Reliability Subcommittee has developed a Power Supply Assessment Methodology to implement the Power Supply Assessment Policy approved by WECC's Board of Directors. The assessment methodology enhances WECC's planning margin assessment procedures by incorporating interarea transmission capability assumptions.

The Underfrequency Load Shedding Work Group has developed a coordinated underfrequency load shedding program for the entire Western Interconnection. This effort was in response to recommendations made following the 1996 system outages in the West. The program has been implemented throughout the WECC region. Recently, the group reviewed the initial underfrequency load shedding program and implemented some clarifications and revisions to the generator off nominal frequency requirement.

Another action WECC has taken in response to recommendations made following the 1996 system outages is implementation of a generator testing program. The tests are to verify the generator capabilities and check plant equipment for proper operations. In addition, the testing incorporates the recording of machine parameters that are used to improve system modeling representation. Certification is awarded for generators that have satisfied the testing requirements. The test work is required for all units larger than ten megawatts.

The WECC Annual Study Program provides an ongoing reliability and risk assessment of the existing and planned western interconnected electric system. To verify that the system is robust and will meet expectations, a wide variety of equipment outages are simulated and results are reviewed for conformance with WECC Reliability Criteria. Recommendations made as a result of the studies are acted upon by the WECC members to maintain interconnected electric system reliability.

Market Interface Committee

The Market Interface Committee (MIC) was formed in 1999 to function as the focal point for the development of consistent market interface practices and compatible commercial practices which might impact the reliability of the Western Interconnection. The purposes of the MIC include the following:

1. Work with the Operating Committee and Planning Coordination Committee to consider matters pertaining to the impact of reliability standards, practices, and procedures on the commercial electricity market and analysis of the impact of electricity market practices on electric system reliability.
2. Facilitate, advise, and make recommendations to the WECC Board regarding the development of consistent market interface practices and compatible commercial practices.
3. Stimulate participation by all market segments of the WECC membership to provide support for the MIC and its subcommittees, task forces, and work groups.
4. In 2005, WECC became a member of the North American Energy Standards Board (NAESB). The Market Interface Committee has a task force for NAESB issues and is developing processes for WECC participation in NAESB.

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Vice Chair	David Areghini, SRP
Chief Executive Officer	Louise McCarren, WECC
Chief Operating Officer	Mark Maher, WECC

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Market Interface Committee Officers

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Operating Committee Officers

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Planning Coordination Committee Officers

Chair	Robert Jenkins, PG&E
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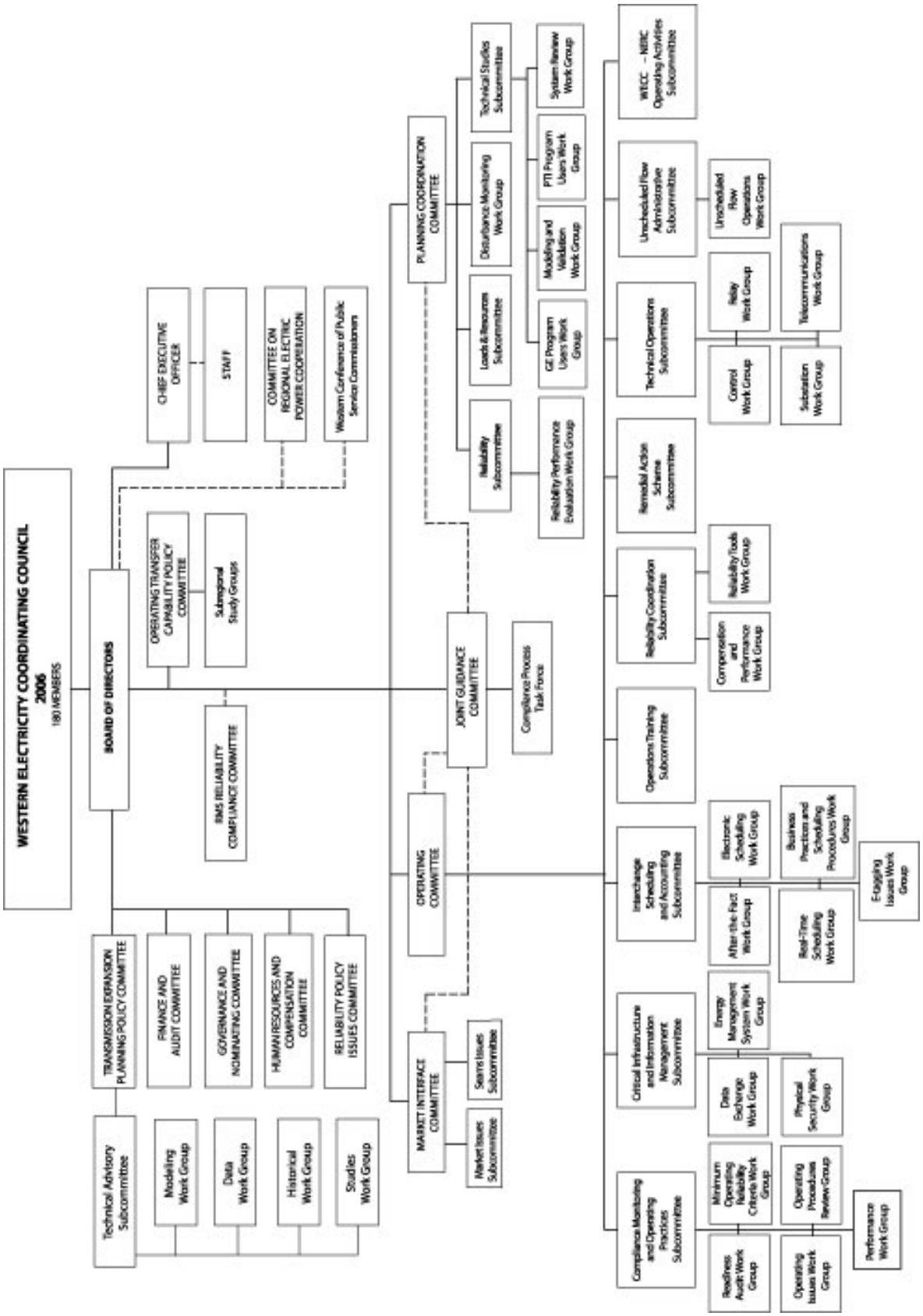
NAD - Non-Affiliated Director


WESTERN ELECTRICITY COORDINATING COUNCIL
2006
180 MEMBERS
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STAFF
COMMITTEE ON REGIONAL ELECTRIC POWER COORDINATION
Western Conference of Public Service Commissioners
OPERATING TRANSFER CAPABILITY POLICY COMMITTEE
Subregional Study Groups
RMS RELIABILITY COMPLIANCE COMMITTEE
TRANSMISSION EXPANSION PLANNING POLICY COMMITTEE
FINANCE AND AUDIT COMMITTEE
GOVERNANCE AND NOMINATING COMMITTEE
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Technical Advisory Subcommittee
Modeling Work Group
Data Work Group
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MARKET INTERFACE COMMITTEE
Seams Issues Subcommittee
Market Issues Subcommittee
OPERATING COMMITTEE
JOINT GUIDANCE COMMITTEE
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PLANNING COORDINATION COMMITTEE
Reliability Subcommittee
Reliability Performance Evaluation Work Group
Loads & Resources Subcommittee
Disturbance Monitoring Work Group
Technical Studies Subcommittee
System Review Work Group
Modeling and Validation Work Group
PTI Program Users Work Group
GE Program Users Work Group
Remedial Action Scheme Subcommittee
Reliability Coordination Subcommittee
Compression and Performance Work Group
Reliability Tools Work Group
Operations Training Subcommittee
Interchange Scheduling and Accounting Subcommittee
Electronic Scheduling Work Group
Business Practices and Scheduling Procedures Work Group
After the Fact Work Group
Real-Time Scheduling Work Group
E-tagging Issues Work Group
Critical Infrastructure and Information Management Subcommittee
Energy Management System Work Group
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Physical Security Work Group
Compliance Monitoring and Operating Practices Subcommittee
Minimum Operating Reliability Criteria Work Group
Operating Procedures Review Group
Performance Work Group
Readiness Audit Work Group
Operating Issues Work Group
Technical Operations Subcommittee
Relay Work Group
Control Work Group
Telecommunications Work Group
Substation Work Group
Unscheduled Flow Administrative Subcommittee
Unscheduled Flow Operations Work Group
WECC – NERC Operating Activities Subcommittee

State of the WECC Interconnected Bulk Power System Through 2015

The WECC region is spread over a wide geographic area with significant distances between load and generation areas. In addition, the northern portion of the region is winter peaking while the southern portion of the region is summer peaking. Consequently, transmission constraints are a significant factor affecting economic grid operation in the region. However, reliability in WECC is best examined at a subregional level. The capacity margins discussed in the subregional assessments assume the planned construction of 20,720 MW by 2015 of net new generation, which is significantly less than the net planned capacity additions of 25,155 MW reorted last year for the 2005-2014 time period. Generation decreased by about 1,150 MW in 2005.

Overview

Due to a slight decrease in existing generating capacity and a significant decrease in reported generation additions, capacity margins for the WECC are reported as declining throughout the ten-year assessment period. The capacity margin declines occur in multiple subregions. WECC's *2006 Power Supply Assessment Report* (PSA) indicates that summer electricity supply shortages relative to study planning margins could occur as early as 2009 and winter electricity supply shortages could occur as early as 2008–2009 in Canada, assuming normal weather, adverse hydroelectric conditions, and no resource additions beyond those presently under active construction with expected in-service dates prior to July 2007 (or July 2008 if coal-fired).

The Rocky Mountain Power Area (RMPA) summer 2007 capacity margin is 9.8 percent without uncommitted resources and 13.2 percent with uncommitted resources. By the summer of 2011, those margins become -0.8 percent and 15.5 percent, respectively. A significant portion of the expected uncommitted resources has received state utility commission approval and is under active development.

Demand

Total internal demand increased by 5.7 percent from 2004 to 2005. Since the 2005 summer temperatures were warmer than normal, projected 2006 summer total internal demand is expected to increase by only 0.7 percent from 149,147 MW in 2005 to 150,177 MW in 2006. Thereafter, summer total internal demand is expected to increase by about 2.2 percent per year compared to 2.4 percent projected last year for 2005–2014.

Demand response and interruptible loads are about 3,070 MW, with about 2,060 MW of the 3,070 MW in California. It should be noted that capacity margins are measured against net internal demand, not total internal demand.

WECC's *2006 Power Supply Assessment Report* (PSA) indicates that summer peak demands may increase region-wide by about an additional 2,100 MW above the forecasted peak and about 2,530 MW above the forecasted 2015 peak, should the region experience a hot spell, similar to that experienced on July 9, 1985. For the winter period, a region-wide increase of almost an additional 2,570 MW in 2006–2007 to about an additional 3,030 MW in 2015–2016 may occur should the region experience a cold spell similar to that experienced on December 22, 1998. The above peak demand weather sensitivities are equivalent to roughly one year or less of normal expected demand growth.

WECC has not established an interconnection-wide process for addressing the issue of planning for peak demand uncertainty and variability in demand due to weather and other conditions. Individual entities within the inter-connection, however, have addressed multiple uncertainties and variability issues as a part of either their integrated resources plan procedures or other similar processes. Those various independent processes generally report that maintaining a reserve margin in the mid-teens would provide sufficient cushion relative to multiple uncertainties.

Energy

Annual energy usage increased by 1.9 percent from 816,079 GWh in 2004 to 831,570 GWh in 2005. The 2005 energy usage was 1.2

percent lower than the forecast in last year's assessment. Annual energy usage for the ten-year period from 2005 through 2014 was forecasted to increase by 2.0 percent compared to the historic annual energy usage increase of 1.9 percent from 1995 through 2005. Annual energy usage for the ten-year period from 2006 through 2015 is forecast to increase by 2.2 percent.

Resources

WECC has not established an interconnection-wide process for assessing resource adequacy. Individual entities within the interconnection, however, have addressed resource adequacy as a part of either their integrated resource plan procedures or some other similar process. Entities within the interconnection have not reported changes in generation/resource planning brought about by the Eastern Interconnection blackout.

The WECC resource data is reduced to reflect nonmetered self-generation and expected wind and adverse hydro limitations. The uncommitted resources reflect reported resource additions that are not under construction or are under construction with reported in-service dates after July 2007 (or July 2008 if coal fired).

Other announced generic resource additions and, generally, projects without identified locations and/or in-service dates, are excluded from the committed and uncommitted resource data. The resource data for the individual WECC-U.S. systems subregions include a potential utilization of seasonal demand diversity between the winter-peaking northwest and the summer-peaking southwest. To avoid double counting of resources, the WECC-U.S. systems net capacity resource totals do not include the diversity utilization. Utilization of the seasonal demand diversity may be limited due to factors such as internal transmission constraints.

WECC's PSA reports that by 2009 summer transfer capability limitations between the northern and southern portions of the Western Interconnection result in a 1,000 MW resource shortfall. The southern portion resource needs increase to roughly 20,000 MW by 2015, even though the northern portion is capacity surplus throughout the period. Although the transmission limitations represented in the PSA analysis are conservative, they are not unreasonable and the report establishes that WECC has insufficient transmission to fully utilize seasonal capacity/demand diversity within the Western Interconnection. A 1,600 MW undersea dc cable has been proposed to interconnect a substation near Portland, Oregon, and the San Francisco Bay area. Completion of the 650-mile interconnection would allow additional California imports of low-cost and renewable electricity from the northwest.

The net resource addition of 20,720 MW used in this report is composed of 6,599 MW of plants under construction and 15,938 MW of plants identified but not presently under construction. The regulatory and financial status of these projects is not known at this time. If the 1,817 MW of planned retirements and other derates occur as scheduled and if no plants are built beyond those already under construction, the WECC capacity margin would drop from 19.4 percent in the summer of 2007 to 11.3 percent by the summer of 2011.

In the near term, WECC entities report firm purchases from Eastern Interconnection entities of about 500 MW, partially offset by firm sales of about 200 MW. By the summer of 2015, purchases decline to about 300 MW and sales decline to about 200 MW.

Fuel

WECC has not implemented a formal fuel supply interruption analysis methodology and does not consider such conditions in any formal assessment process. Historically, coal-fired plants have been built at or near their fuel source and generally have long-term fuel contracts with the mine operators, or actually own the mines. Gas-fired plants were historically located near major load centers and relied on relatively abundant western gas supplies. While a few of the older gas-fired generators in the region have backup fuel capability and normally carry an inventory of backup fuel, most of the newer generators are strictly gas-fired plants, increasing the region's exposure to interruptions to that fuel source. This is particularly true for California, which is highly reliant on gas-fired generation and has only three plants that maintain dual-fuel capability.

The natural gas supply system within WECC is fairly robust and the region is not highly dependent on external natural gas supplies. However, the western gas transmission system is interconnected with external transmission systems so gas deliveries can be redirected to other regions. Many individual entities have fuel supply interruption mitigation procedures in place, including on-site coal storage facilities. However, on-site natural gas storage is generally impractical so gas-fired plants rely on the general robustness of the pipeline delivery system and firm supply contracts. WECC does not impose fuel supply requirements on its members.

Transmission

Transmission facilities are planned in accordance with NERC and WECC planning standards. Those standards establish performance levels intended to limit the adverse effects of each transmission system's operation on others and recommend that each system provide sufficient transmission capability to serve its customers, to accommodate planned interarea power transfers, and to meet its transmission obligation to others.

The standards do not require construction of transmission to address intraregional transfer capability constraints. WECC, in conjunction with MRO and SPP, studies intra-area power transfer capabilities.

During the study period, entities within WECC plan to add 5,951 miles of transmission lines.

Operations

Under WECC's regional reliability plan, three reliability centers have been established for the region in California, Colorado, and Washington. The reliability coordinators are charged with actively monitoring, on a real-time basis, the interconnected system conditions on a wide-area basis to anticipate and mitigate potential reliability problems and to coordinate system restoration should an outage occur.

The blackout in the Eastern Interconnection has increased awareness regarding ongoing tree trimming programs, and several entities within WECC have reported increased long-range transmission right-of-way clearance work.

WECC operations personnel are progressing on implementing an interconnected system operating condition model.

Significant amounts of thermal generation within WECC are subject to air emission limitations. The limitations may adversely affect operating costs and flexibility but are not expected to reduce margins.

No extended major unit outages or temporary operating measures have been reported that may impact reliability for extended periods over the next ten years. Operational issues are expected to center around issues such as transmission congestion management, hydroelectric energy generation limitations, and integration of renewable resources.

Assessment Process

Each year WECC prepares a transmission study report that provides an ongoing reliability-security assessment of the WECC interconnected system in its existing state and for system configurations planned through the next ten years. The disturbance simulation study results are examined relative to NERC and WECC planning standards. If study results do not meet expected performance levels established in the criteria, the responsible organizations are obligated to provide a written response that specifies how and when they expect to achieve compliance with the criteria. Other measures that have been implemented to reduce the likelihood of widespread system disturbances include: an islanding scheme for loss of the AC Pacific Intertie that separates the Western Interconnection into two islands and drops load in the generation-deficit southern island; a coordinated off-nominal frequency load shedding and restoration plan; measures to maintain voltage stability; a comprehensive generator testing program; enhancements to the processes for conducting system studies; and a reliability management system.

- Operating Transfer Capability Policy Committee Process:

  Operating studies are reviewed to ensure that simultaneous transfer limitations of critical transmission paths are identified and managed through nomograms and operating procedures. Four subregional study groups prepare seasonal transfer capability studies for all major paths in a coordinated subregional approach for submission to WECC's Operating Transfer Capability Policy Committee.

On the basis of these ongoing activities, transmission system reliability within the Western Interconnection is expected to meet NERC and WECC standards throughout the ten-year period.

SUBREGIONAL ASSESSMENTS

NORTHWEST POWER POOL AREA

Demand — The Northwest Power Pool (NWPP) area is comprised of all or major portions of the states of Idaho, Montana, Nevada, Oregon, Utah, Washington, and Wyoming; a small portion of northern California; and the Canadian provinces of British Columbia and Alberta. For the period from 2006 through 2015, winter total internal demands are projected to grow at annual compound rates of 1.6 percent and 1.9 percent in the United States and Canadian areas, respectively.

WECC's 2006 PSA indicates that summer peak demands may increase by about an additional 490 MW in 2006 to about 565 MW in 2015 should the region experience a hot spell similar to that experienced on July 9, 1985. For the winter period, an increase of almost an additional 1,940 MW in 2006–2007 to about an additional 2,230 MW in 2015–2016 may

occur should the region experience a cold spell similar to that experienced on December 22, 1998.

Energy — Annual energy usage increased by 3.9 percent from 347,313 GWh in 2004 to 360,889 GWh in 2005. The 2005 energy usage was 1.9 percent greater than the forecast in last year's assessment. Annual energy usage for the ten-year period from 2005 through 2015 is forecast to increase by 1.9 percent compared to the historic annual energy usage increase of 1.3 percent from 1995 through 2005. Annual energy requirements are projected to grow at annual compound rates of 1.9 percent and 2.1 percent in the U.S. and Canada areas, respectively.

Resources — The data for the United States portion of the NWPP present winter 2007/2008 capacity margins of 28.4 percent without uncommitted resources and 30.0 percent with uncommitted resources. By winter 2011/2012, those margins change to 23.7 percent and 30.3 percent, respectively. For the Canadian portion of the NWPP, the winter 2007/2008 capacity margins are 7.6 percent without uncommitted resources and 9.4 percent with uncommitted resources. By winter 2011/2012, those margins decline to -1.1 percent without uncommitted resources and 5.1 percent with uncommitted resources. The Canadian entities are aware of the resource adequacy issue for their areas and have instituted very active resource acquisition and transmission reinforcement processes.

NWPP planning is conducted by sub-area. Idaho, northern Nevada, Wyoming, Utah, British Columbia, and Alberta individually optimize their resources to their demand. The coordinated system (Oregon, Washington, and western Montana) coordinates the operation of its hydro resources to serve its demand. In 2001, the northwest experienced its second lowest Coordinated Columbia River System volume runoff since record keeping began, with reservoirs refilling to just 71 percent of capacity, the lowest levels in almost a decade. Since 2001, the reservoir refill has ranged between 87 percent and 92 percent of capacity.

The reservoirs are managed to address all of the competing requirements including but not limited to: current electric power generation, future (winter) electric power generation; flood control; fish and wildlife requirements; special river operations for recreation; irrigation; navigation; and refilling of the reservoirs. In addition to managing the competing requirements, other available generating resources, market conditions, and load requirements are considered and incorporated into the decision for refilling the reservoirs. Any time precipitation levels are below normal, balancing these interests becomes even more difficult. A ten-year agreement was reached in 2000 among parties involved in operation of the Columbia River Basin concerning river operations. However this agreement is subject to three-, five-, and eight-year performance checks and reopening by the parties. The net impact of the agreement is a reduction in generating capability as a result of hydro generation spill policies designed to favor fish migration. The capability reduction, which varies depending on water flows and other factors, is reflected in the margin calculations presented in this report. The agreement includes a provision for negotiating changes in the plan under emergency conditions as occurred in 2001.

Generation in the province of Alberta, Canada, operates in a fully deregulated market and thus resource additions are market driven. Generation additions and load growth are expected to result in some transmission constraints in a number of areas over the course of the review period if identified system reinforcements are not completed on time. The impact of most of these constraints is anticipated to be local in nature and will not impact the transmission systems outside of Alberta.

The subregion has not established a process for assessing resource adequacy. Individual entities within the subregion, however, have addressed resource adequacy as a part of either their integrated resource plan procedures or some other similar process. Entities within the subregion have not reported changes in generation/resource planning brought about by the Eastern Interconnection blackout.

Fuel — A significant portion of the electric power generated in the Pacific Northwest is derived from hydroelectric generation. Hence, wide variations in annual precipitation, water storage and flow limitations, and other factors significantly affect energy generation from other resources and complicate the fuel planning processes. Coal-fired generation in the area is also very significant. Much of the coal fired generation has near-fuel sources and is often operated in a base-load mode. Consequently, the area is not highly reliant on gas-fired plants relative to annual energy generation and many of those plants are more often operated as seasonal peaking units. Wind-powered generation is increasing rapidly in the area. Since the wind resources exhibit wide fluctuations in output, areas with relatively large amounts of wind-powered generation are investigating potential interconnection limitations as necessary to minimize adverse consequences that may occur.

Transmission — In view of the longer time required for transmission permitting and construction, it is recognized that network planning should focus on establishing a flexible grid infrastructure. This is being done with the goals of allowing anticipated transfers among NWPP systems, addressing several areas of constraint within Washington, Oregon, Montana, and other areas within the region, and integrating new generation. Projects at various stages of planning and implementation include approximately 986 miles of 500-kV transmission lines.

Maintaining the capability to import power into the Pacific Northwest during infrequent extreme cold weather periods continues to be an important component of transmission grid operation. In order to support maximum import transfer capabilities under double-circuit simultaneous outage conditions, the northwest depends on an automatic underfrequency load shedding scheme.

Approvals for two major system developments have been received from the Alberta provincial regulatory authority. The first of these is for the development of approximately 105 kilometers (65 miles) of 240-kV transmission line to accommodate several new wind generation developments in southwest Alberta. This development has an in-service date of 2007.

The second approval is for the construction of a 500-kV line, approximately 330 kilometers (200 miles) in length, to strengthen the main north-south transmission grid. This development has a proposed in-service date of 2009. In conjunction with this project, approval to install 520 Mvar of capacitor banks in the Calgary area has also been received. The capacitor banks were placed in service at the end of 2005.

A Calgary area transmission must run (TMR) procedure has been updated to address the 240-kV transmission grid-loading issues and to ensure that voltage stability margins are maintained. The TMR service is an ancillary service contract with generators that is required to address contingencies in areas of inadequate transmission to help provide voltage support to the transmission system in southern Alberta, near Calgary, and assist in maintaining overall system security.

Increased local area load has reduced the export capability of the Alberta-Saskatchewan dc tie. A planning study is currently under way to analyze the Empress area and the Alberta-Saskatchewan dc tie export capability. The study and recommendations are expected to be completed by December 2006. Applications for additional transmission developments will be filed as required.

The Canadian province of British Columbia relies on hydroelectric generation for 90 percent of its resources. British Columbia Hydro and Power Authority is addressing constraints between remote hydro plants and lower mainland and Vancouver Island load centers. The definition phase of a new 500-kV line between Nicola and Meridian substations and a 230-kV underwater cable between Arnott substation and Vancouver Island terminal is under way.

The new 500-kV line will increase the total transfer capability of the interior to lower mainland area grid and the new 230-kV cable will increase the transfer capability from the lower mainland area to Vancouver Island. These projects have proposed in-service dates of 2013 and 2008, respectively.

Operations — Under normal weather conditions, the NWPP does not anticipate dependence on imports from external areas during summer peak demand periods. In the event of either extreme weather or much lower than normal precipitation, the NWPP could increase imports, which would reduce reservoir drafts and aid reservoir filling. Off-peak energy transfers allow southwest generators to increase thermal plant loading during normally light load hours to offset to some extent the

Proposed NWPP Projects > 50 Miles	Status	In-service Date
Cordell, AB to Metiskow, AB 240-kV line	Completed	November 2005
Ellensburg, WA to Sunnyside WA 500-kV line	Completed	December 2005
Goose Lake to N. Lethbridge, AB 240-kV line	Permitting	2007
Benewah, ID to Shawnee, WA 230-kV line	Planning	2007
Montana-Alberta 230-kV merchant line	Permitting	2007
American Falls, ID to Hunt, ID 230-kV line	Under way	2007
Vancouver Island-Arnott 230-kV line	Planning	2008
Keephills-Genesee-Ellerslie, AB 500-kV line	Permitting	2009
Genessee, AB to Langdon, AB 500-kV line	Permitting	2009
Cranbrook, BC to Invermere, BC 230-kV line	Planning	2011
Mona, UT to Salt Lake, UT 345-kV line	Planning	2007 / 2011
Nicola, BC to Meridian, BC 500-kV	Planning	2013
Southwest Intertie project (ID-NV 260 mile tie)	Planning	2013

effects of any adverse hydro conditions.

WECC's 2006 PSA report notes that transmission constraints exist between the United States and Canadian portions of the NWPP and that by 2015 over 3,000 MW of additional capacity (generation or transmission for imports) will be needed in Canada. Both provinces are addressing the capacity issue. For example, British Columbia recently announced the awarding of a few dozen contracts representing over 1,500 MW of capacity.

ROCKY MOUNTAIN POWER AREA

Demand — The Rocky Mountain Power Area (RMPA) consists of Colorado, eastern Wyoming, and portions of western Nebraska and South Dakota. The RMPA may experience its annual peak demand in either the summer or winter season due to variations in weather. For the period from 2006 through 2015, summer total internal demands and annual energy requirements are projected to grow at annual compound rates of 2.4 percent and 2.2 percent, respectively.

WECC's 2006 PSA report indicates that summer peak demands may not increase should the region experience a hot spell similar to that experienced on July 9, 1985. For the winter period, an increase of almost an additional 50 MW in 2006–2007 to about an additional 60 MW in 2015–2016 may occur should the region experience a cold spell similar to that experienced on December 22, 1998.

Energy — Annual energy usage increased by 3.4 percent from 57,214 GWh in 2004 to 59,190 GWh in 2005. The 2005 energy usage was 4.3 percent less than the forecast in last year's assessment. Annual energy usage for the ten-year period from 2005 through 2015 is forecast to increase by 2.1 percent compared to the historic annual energy usage increase of 3.1 percent from 1995 through 2005. Annual energy usage for the nine-year period from 2006 through 2015 is forecast to increase by 2.2 percent.

Resources — The data for the Rocky Mountain Power Area (RMPA) present the summer 2007 capacity margins of 9.8 percent without uncommitted resources and 13.2 percent with uncommitted resources. By the summer of 2011, those margins become -0.8 percent and 15.5 percent, respectively. A significant portion of the expected uncommitted resources has received state utility commission approval and is under active development.

Due to extended drought, hydro generation is at low levels along the North Platte River. The low flows have impacted cooling water availability at a major coal-fired plant, requiring acquisition of groundwater rights as a supplemental water source. Water levels in Lake Powell, which is the reservoir for Glen Canyon dam generation, are expected to end the 2006 water year 70 feet below full. This results in a capacity reduction of about 170 MW (14 percent) due to a lower hydraulic head at the plant.

Tri-State Generation and Transmission Association announced plans in late 2005 to construct two 600 MW coal-fired units at the Holcomb generator site near Garden City, Kansas. Plant in-service dates are slated for a 2012–2013 time frame. Basin Electric Power Cooperative is developing the Dryfork 385 MW coal plant near Gillette, Wyoming, with a 2011 in-service date. Public Service Company of Colorado (PSC) is in the process of a request for proposals (RFP) for new resources to meet its needs through 2010. PSC already has 300 MW of wind generation integrated into its system as of 2006. PSC has received approval to construct a 750 MW coal-fired plant at the existing Comanche station in 2010, and plans on adding 1,600 MW of other resources over the next five years. The RMPA margins referred to above do not include the possible 1,600 MW resource additions.

The subregion has not established a process for assessing resource adequacy. Individual entities within the subregion, however, have addressed resource adequacy as a part of either their integrated resource plan procedures or some other similar process.

Fuel — Coal, hydro, and gas-fired plants are the dominant electricity sources in the area. Much of the coal is provided by relatively nearby mines and is often procured through long-term contracts. Hydroelectric plants, however, may experience operational limitations due to variations in precipitation. As in the northwest, gas-fired plants are most often operated in a peaking mode. Abundant natural gas supplies exist within the area but delivery constraints may occur at some plants during unexpected severe cold weather conditions.

Transmission — The Western Area Power Administration (WAPA) plans to upgrade several 115-kV transmission lines to 230 kV over the next ten years to increase transfer capabilities and to help maintain the operating transfer capability between southeastern Wyoming and northeastern Colorado. In addition to those conversions, the table on the next page, describes additional transmission projects.

Operations — Transmission upgrades in the area have alleviated some transfer capability limitations, but some system constraints remain. Operator flexibility will be limited by the transmission

Proposed RMPA Projects > 50 Miles	Status	In-service Date
Carr Draw-Hartzog-Teckla, WY 230-kV lines	Completed	November 2005
Walsenburg, CO to Gladstone, NM 230-kV line	Under way	Late 2007
Hughes, WY to Sheridan, WY 230-kV line	Planned	2008
San Luis Valley-Walsenburg, CO 230-Kv line	Planned	2009
Upgrades to Path 36 (TOT3) between southeast Wyoming and northeast Colorado	Under way	2009
Comanche-Daniels Park #1 & #2 345-kV lines	Planned	May 2009
Beaver Creek-Erie #2 230 kV	Under way	2010
Holcomb, KS to Front Range, CO 500 kV	Planned	2011

constraints and operating conditions must be closely monitored, especially during periods of high demand. In some cases, special protection schemes are utilized to preserve system adequacy should multiple outage contingencies occur.

ARIZONA-NEW MEXICO-SOUTHERN NEVADA POWER AREA

Demand — The Arizona-New Mexico-Southern Nevada (AZ-NM-SNV) power area consists of Arizona, most of New Mexico, southern Nevada, the westernmost part of Texas, and a portion of southeastern California. For the period from 2006 through 2015, summer total internal demands and annual energy requirements are projected to grow at annual compound rates of 2.9 percent.

WECC's 2006 PSA report indicates that summer peak demands may increase by about an additional 45 MW in 2006 to about 55 MW in 2015 should the region experience a hot spell similar to that experienced on July 9, 1985. For the winter period, an increase of almost an additional 50 MW in 2006–2007 to about an additional 65 MW in 2015–2016 may occur should the region experience a cold spell similar to that experienced on December 22, 1998.

Energy — Annual energy usage increased by 2.9 percent from 122,940 GWh in 2004 to 126,540 GWh in 2005. The 2005 energy usage was 1.0 percent greater than the forecast in last year's assessment. Annual energy usage for the ten-year period from 2005 through 2015 was forecasted to increase by 2.8 percent compared to the historic annual energy usage increase of 3.7 percent from 1995 through 2005. Annual energy usage from 2006 through 2015 is forecast to increase by 2.9 percent.

Resources — The data for this sub-area present the summer 2007 capacity margins of 19.6 percent without uncommitted resources and 19.8 percent with uncommitted resources. By the summer of 2011, those margins become 8.4 percent and 13.7 percent, respectively. As in the RMPA, a significant portion of the uncommitted resources has received state utility commission approval and is under active development.

As with other areas within WECC, the future adequacy of the generation supply over the next ten years in this area will depend on how much new capacity is actually constructed. Generally, the proposed plants have relatively short construction times once the decision is made to proceed, although an expansion of the Springerville coal-fired plant is under way with one unit under construction and an additional unit scheduled to be in commercial operation by late 2009. Frequently, resource acquisitions are subject to a request for proposal process that may increase the uncertainty regarding plant type, location, etc.

Proposed AZ/NM/SNV Projects > 50 Miles	Status	In-service Date
Harry Allen, NV to Mead 500-kV line	Under way	2007
Stirling Mt-Northwest-Vista, NV 230-kV line	Planned	2007
Palo Verde-TS5 500-kV line	Permitted	2009
Palo Verde to Southeast Valley (Phoenix area)	3 Parts	2011
A. Hassayampa to Pinal West 500-kV line	Under way	2008
B. Pinal West to Santa Rosa 500-kV line	Under way	2008
C. Santa Rosa to Browning 500-kV line	Permitted	2011
Centennial II (Las Vegas, NV area) 500-kV line	Planning	2011
TS5-Raceway 500-kV line	Planning	2012
Pinal West-Tortolita, AZ 500-kV line	Planning	2012
Palo Verde-North Gila 500-kV line	Planning	2012
Shiprock, NM to Marketplace, NV 500-kV line	Permitted	2010 / 2013
Northern to central New Mexico 345-kV generation outlet lines	Planning	2013
Greenlee-Springerville, AZ #2 345-kV line	Planning	2014
Tucson, AZ area 345-kV reinforcements	Planning	2014
Nogales, AZ to Sahuarita, AZ 345-kV lines	Planned	2014

These factors combine to make generation adequacy forecasting problematic for an extended period of time.

The subregion has not established a process for assessing resource adequacy. Individual entities within the subregion, however, have addressed resource adequacy as a part of either their integrated resource plan procedures or some other similar process.

Fuel — Coal, hydro, and nuclear plants are the dominant electricity sources in the area. As in the northwest, gas-fired plants are most often operated in a peaking mode. Much of the coal is provided by relatively nearby mines and is often procured through long-term contracts. Major hydroelectric plants are located at dams with significant storage capability so short-term variations in precipitation are not a significant factor in fuel planning.

Transmission — Transmission providers from the AZ-NM-SNV Power area are actively engaged in the Southwest Transmission Expansion Planning (STEP) group along with stakeholders from southern California. The goal of this group is to participate in the planning, coordination, and implementation of a robust transmission system between the Arizona, southern Nevada, Mexico, and southern California areas that is capable of supporting a competitive, efficient, and seamless west-wide wholesale electricity market while meeting established reliability standards. Three projects have resulted from the study efforts to upgrade the transmission path from Arizona to southern California and southern Nevada. The three projects will increase the transmission path capability by about 3,000 MW. The first set of upgrades will increase the transfer capacity by 505 MW and will be completed in 2006. The second set of upgrades will increase the transfer capacity by 1,245 MW and is scheduled to be completed in 2008. The last set of upgrades is the Palo Verde to Devers #2 500-kV transmission line reported in the California-Mexico power area table.

Operations — Special protection schemes play an important role in maintaining system adequacy should multiple system outages occur. These schemes include generator tripping in response to specific transmission line outages. In addition, operators rely on procedures such as operating nomograms so that the system can respond adequately to planned and unplanned transmission and/or generation outages.

CALIFORNIA-MEXICO POWER AREA

Demand — The California-Mexico power area encompasses most of California and the northern portion of Baja California, Mexico. Summer total internal demands are currently projected to grow at annual compound rates of 1.9 percent and 4.5 percent in the United States and Mexican areas, respectively, from 2006 through 2015. Annual energy requirements are projected to grow at annual compound rates of 1.9 percent and 5.1 percent in the U.S. and Mexican areas, respectively.

WECC's 2006 PSA report indicates that summer peak demands may increase by about an additional 1,565 MW in 2006 to about 1,910 MW in 2015 should the region experience a hot spell similar to that experienced on July 9, 1985. For the winter period, an increase of almost an additional 530 MW in 2006– 2007 to about an additional 675 MW in 2015–2016 may occur should the region experience a cold spell similar to that experienced on December 22, 1998.

Energy — Annual energy usage decreased by 1.3 percent from 288,612 GWh in 2004 to 284,951 GWh in 2005. The 2005 energy usage was 5.2 percent less than the forecast in last year's assessment, due to generally mild weather conditions throughout much of the year. Annual energy usage for the ten-year period from 2005 through 2015 was forecasted to increase by 1.8 percent compared to the historic annual energy usage increase of 1.7 percent from 1995 through 2005. Annual energy usage for the nine-year period from 2006 through 2015 is forecast to increase by 2.1 percent.

Resources — The data for the United States portion of the California-Mexico sub-area present summer 2007 capacity margins of 13.5 percent without uncommitted resources and 13.7 percent with uncommitted resources. By summer 2011, those margins become 10.8 percent and 12.6 percent, respectively. For the Mexican portion of the subregion, the summer of 2007 capacity margins are 12.3 percent without uncommitted resources and 15.4 percent with uncommitted resources. By summer 2011, those margins become -4.8 percent and 22.3 percent, respectively. The Mexican uncommitted resources include plans for a 228 MW combined-cycle plant at San Luis Rio, Colorado, with a 2008 expected in-service date.

The summer of 2007 data for the United States portion of the California-Mexico subarea includes 2,534 MW of possible diversity utilization, of total net imports from 7,517 MW, which is below historic summer import levels. By 2011, however, the possible diversity utilization resource component is increased to 5,648 MW with total net imports at 10,445 MW. Beyond about 2011, the possible diversity utilization becomes problematic due to possible

Proposed CA/MX Projects > 50 Miles	Status	In-service Date
La Jovita Project, MX 230-kV lines	Planning	2009
Palo Verde-Devers #2 500-kV line	Permitting	2009
Imperial Valley-San Diego 500-kV line	Planning	2010
Indian Hills-Upland 500-kV line	Planning	2010
New Vincent-Mira Loma 500-kV line	Planning	2011
Tehachapi Area Transmission — 500 kV	Permitting	2010–2011

resource inadequacies in other subregions and due to possible transmission constraints.

Uncertainty surrounding responsibility to acquire resources in California has raised questions regarding future projections of generating capacity, energy production by generators, and effects of customer energy efficiency and other demand-side management programs. For example, four years ago over 45,000 MW of planned resource additions were reported for the area for the 2002–2011 ten-year period. This year's assessment reports a continued decrease to 3,160 MW for the 2006–2015 period compared to 6,783 MW reported last year for the 2005–2014 period.

The *California Energy Commission's Energy Action Plan II*, dated September 21, 2005, notes that cost effective energy efficiency is the resource of first choice for meeting California's energy needs and presents a key action item that all cost-effective energy efficiency be integrated into utilities' resource plans on an equal basis with supply-side resource options. Should this happen, loads supplied through the bulk power system will not grow as fast as projected in this report.

The state is implementing a mandatory minimum reserves requirement to achieve resource adequacy and is looking to new customer electricity metering equipment as a key component to achieving demand response goals. State entities are working together and with other entities in the Western Interconnection to address transmission planning issues.

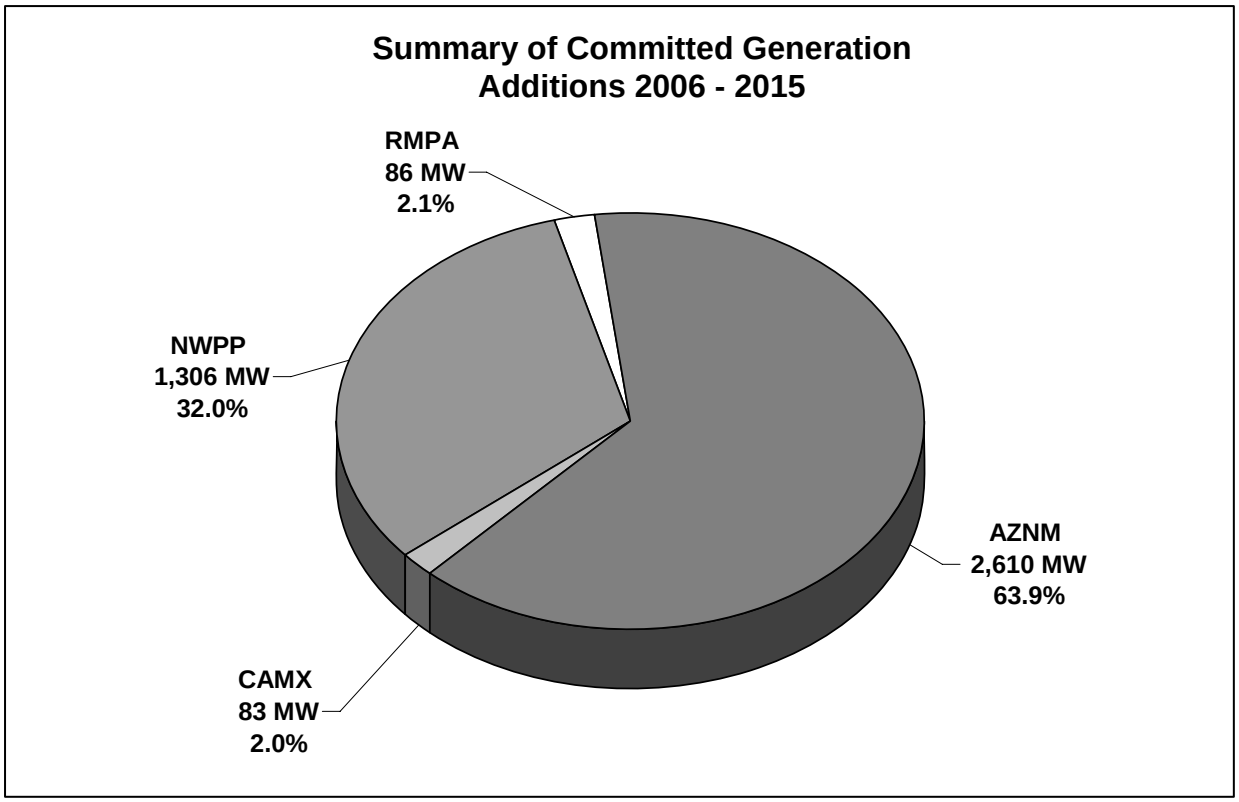
The subregion has not established a process for assessing resource adequacy. Individual entities within the subregion, however, have addressed resource adequacy as a part of either their integrated resource plan procedures or some other similar process.

Fuel — California is highly reliant on gas-fired generation and has very little alternate fuel capability for these plants. California is also highly reliant on natural gas imports so gas supply is of concern to area energy planners, including the California Energy Commission. The Commission's September 21, 2005 *Energy Action Plan II Implementation Roadmap For Energy Policies* identifies eight key actions to address natural gas supply, demand, and infrastructure. The report is available at:

http://www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.PDF.

Transmission — Since the addition of several generating plants in Arizona, southern Nevada, and Mexico, the bulk power system into southern California has become increasingly congested due to the desire to increase imports from the surrounding areas. Special protection schemes have been implemented for generation connected to the Imperial Valley substation in order to relieve some of the congestion and an operating nomogram is used to limit the simultaneous operation of generating plants connected to the Imperial Valley substation and imports from CFE and Arizona. The CISO anticipates that the 500-kV interconnection between Arizona and California that connects to the Imperial Valley substation will be constrained most of the time due to increased imports from new southwest generation.

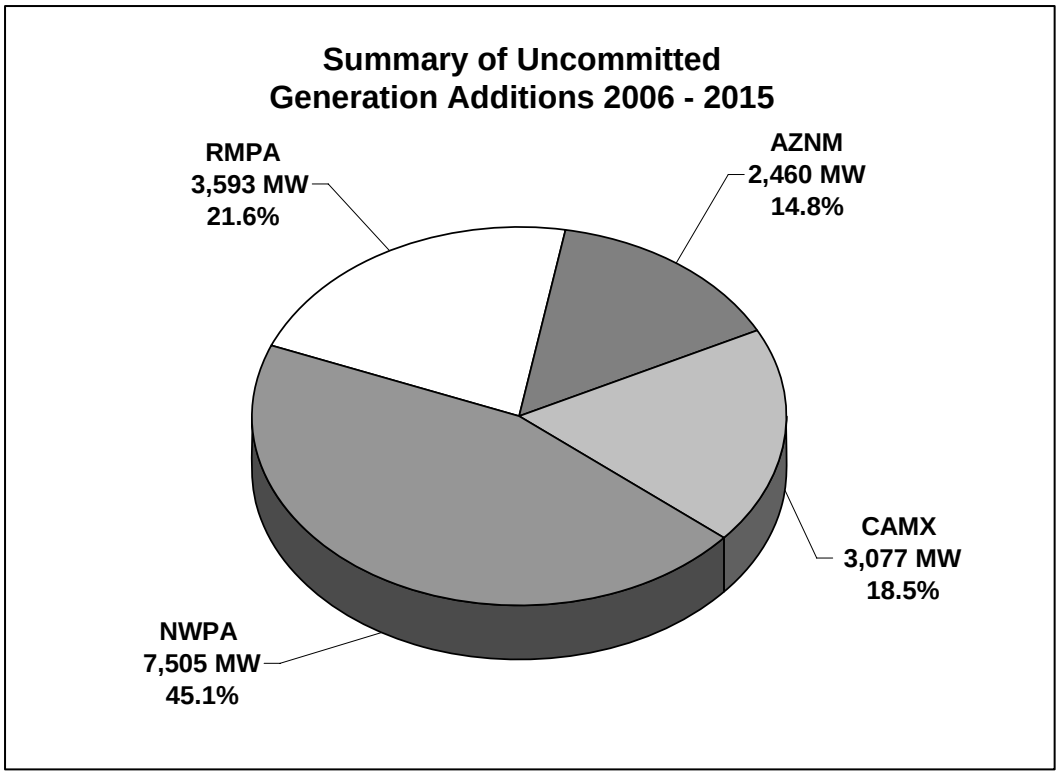
Operations — The California ISO (CAISO) is moving forward on a Market Redesign and Technology Upgrade (MRTU) program of changes to ISO market and grid operations. The CAISO has set a November 2007 launch date for the MRTU program, which includes upgrades to the CAISO's computer technology to a scalable system that can grow and adapt to future system requirements. Transmission upgrades in the area have alleviated some transfer capability limitations, but numerous system constraints remain. Operator flexibility is limited by the transmission constraints and is further impacted by forest and brush fires that often occur during high-demand periods. The CAISO and other entities within the subregion are interacting in developing an integrated transmission plan for the state to address significant constraint issues.



WECC Committed Generation Additions 2006 - 2015

Table 1 -Summary of Committed Generation Additions 2006 - 2015

Generation Type	Northwest Power Pool Area	Rocky Mountain Power Area	Arizona New Mexico So. Nevada Power Area	California Mexico Power Area	WECC Total	% of Total
Hydro - Conventional	166	0	0	2	168	4.1
Hydro - Pumped Storage	0	0	0	0	0	0.0
Steam - Coal	112	80	435	-1580	-953	-23.3
Steam - Oil	0	0	0	0	0	0.0
Steam - Gas	0	0	0	-163	-163	-4.0
Nuclear	0	0	71	0	71	1.7
Combustion Turbine	-52	0	98	-52	-6	-0.1
Combined Cycle	899	0	2005	1832	4736	115.9
Geothermal	35	0	0	0	35	0.9
Internal Combustion	54	0	0	0	54	1.3
Other	92	6	1	44	143	3.5
Total	1306	86	2610	83	4085	100.0
Percent of WECC Total	32.0	2.1	63.9	2.0	100.0	



WECC Summary of Uncommitted Generation Additions 2006 - 2015

Table 2 - Summary of Uncommitted Generation Additions 2006 - 2015

Generation Type	Northwest Power Pool Area	Rocky Mountain Power Area	Arizona New Mexico So. Nevada Power Area	California Mexico Power Area	WECC Total	% of Total
Hydro - Conventional	1112	0	0	0	1112	6.7
Hydro - Pumped Storage	0	0	0	390	390	2.4
Steam - Coal	3743	2335	400	0	6478	38.9
Steam - Oil	0	0	-128	0	-128	-0.8
Steam - Gas	15	0	-174	0	-159	-0.9
Nuclear	0	0	71	0	71	0.4
Combustion Turbine	602	534	-79	81	1138	6.8
Combined Cycle	1057	646	2166	2498	6367	38.3
Geothermal	0	0	195	0	195	1.2
Internal Combustion	0	0	0	0	0	0.0
Other	976	78	9	108	1171	7.0
Total	7505	3593	2460	3077	16635	100.0
Percent of WECC Total	45.1	22	14.8	18.5	100.0	

Loads and Resources

Net generation additions (20,700 MW) projected over the next ten years are significantly less than the net generation additions (32,080 MW) placed in service during the past ten years. The amount of planned resource additions largely reflects independent power producers' response to perceived market opportunities.

Increased generation is projected from combined cycle sources during the next ten years. Combined cycle resources are expected to increase by 53.5 percent and will account for 23.5 percent of total resources by 2015. The remaining resources projected for 2015 include: 29.9 percent hydroelectric, 20.5 percent steam-coal, 9.0 percent steam-gas, 4.6 percent nuclear, 8.3 percent combustion turbine, and 4.3 percent miscellaneous.

The Planning Coordination Committee is charged with the responsibility for annually compiling and reporting the WECC members' plans for meeting the region's projected peak demand and energy requirements.

The information presented herein via tables and figures summarizes load and resource information for the WECC region. Additional information follows for each of the four major areas within WECC – Northwest Power Pool Area (NWPP), Rocky Mountain Power Area (RMPA), Arizona-New Mexico-Southern Nevada Power Area (AZ-NM-SNV), and California-Mexico Power Area (CA-MX).

Introducing the data for each area is an area map, a list of significant organizations within that area (some of these organizations collect data from smaller organizations in the area), and a figure depicting the area's load and resource history (1995-2005) and current ten-year projection (2006-2015). The data used in plotting the historical load and resource curves are included in the Appendix.

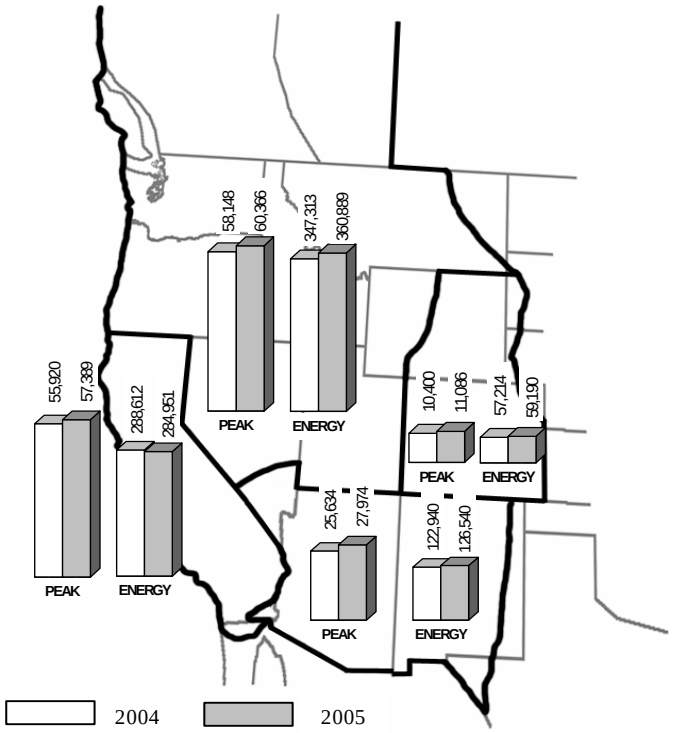
Table 3 on page 28, summarizes the 2005 actual monthly load and resource data for the WECC region and provides a comparison with the total peak demand and energy loads projected as of January 1, 2005. Actual monthly peak demand and energy requirements that were lower than projected are indicated in the tables by negative forecast deviations.

The WECC 2005 non-coincidental peak demand of 149,147 MW occurred in July, representing a 5.7 percent increase relative to the 2004 peak demand of 141,100 MW which also occurred in July. The July 2005 peak was 2.0 percent above the forecast summer peak demand. Temperatures were generally normal to above normal in most of the WECC region during the 2005 summer period.

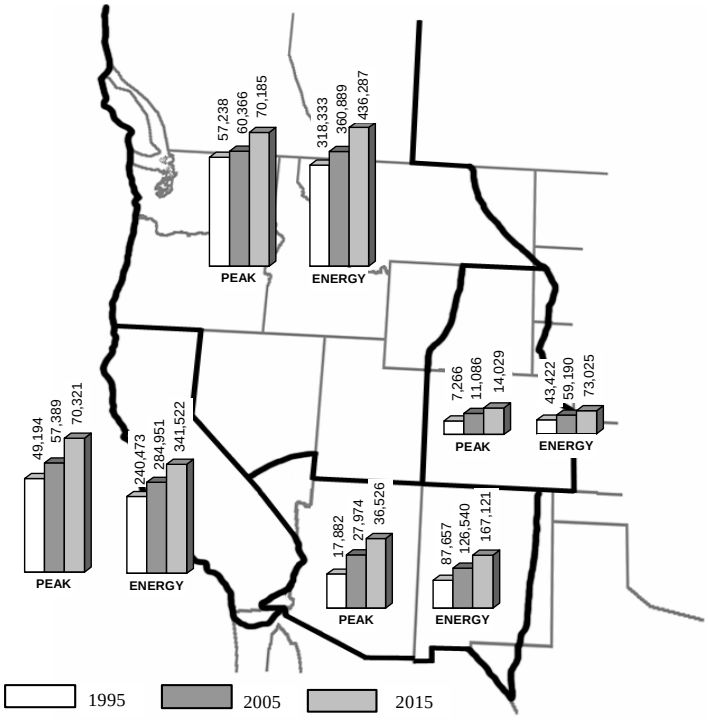
The 2005-2006 winter peak demand of 128,934 MW occurred in December, 2005 and was 1.35 percent above the forecast winter peak demand and 4.36 percent above the 2004-2005 winter peak demand. Temperatures were generally normal in the 2005-2006 winter period, whereas the temperatures were in the normal to above normal range in some areas during the 2004-2005 winter period. The top graph on the following page presents the 2004 and 2005 peak demands and energy loads for the WECC areas.

WECC's 2005 annual energy requirement of 831,570 GWh was 1.9 percent above the 2004 annual energy requirement of 816,079 GWh. The region's 2005 annual energy requirement was 1.2 percent below forecast. The bottom graph on the next page presents the 1995, 2005 and 2015 annual peaks (MW) and energy loads (in GWh) for the WECC areas.

Table 4 on page 29, tabulates on a regional and area basis the projected peak demand average annual compound growth rates based on the previous year's actual peak demand and the ten-year forecast as of January 1 of each year from 1995 through 2005.



2004 and 2005 Peak Demands (MW) and Energy Load (GWH)



1995, 2005, 2015 Annual Peaks (MW) and Energy Loads (GWH)

The 2005-2015 projected peak demand growth rate of 2.1 percent for the WECC region is less than the 2.5 percent growth rate projected last year for the 2004-2014 period. Figure 2 on page 29, depicts the region's peak demand history (1995-2005) and the ten-year projection as of January 1, 2006. Figure 2 also depicts the 1997 and 2005 ten-year load growth projections.

Tables 5 and 6 summarize the actual annual peak demand and energy requirement growth rates for the 1995-2005 period. The wide variation in peak demand growth rates primarily reflects a sensitivity to extremes in seasonal temperature fluctuations from year to year. The variations in annual energy requirement growth rates are primarily due to changes in economic activity in the areas.

Table 7 provides information regarding the ten-year projection for summer and winter peak demands, resources, scheduled maintenance/inoperable capability, and reserve capability for the total WECC region. The reserves depicted for the total WECC region should not be used to assess the adequacy of power supply within WECC as transmission constraints may limit inter-area capacity transfers. Table 8 is a summary of the projected summer and winter peak demand growth rates for WECC and each of its four major areas. The summer and winter seasons are defined as the periods of the year between June 1 and September 30, and between December 1 and the end of February of the following year, respectively.

A summary of the 2006-2015 annual energy requirements for WECC and its four major areas is presented in Table 9. Hydro-pumped storage pumping requirements will increase the energy requirements above those

shown for the WECC region. Table 10 summarizes the projected energy growth rates.

As of January 1, 2006, WECC's existing generating capability totaled 188,429 MW. This figure represents a net decrease in capability over that reported January 1, 2005, of 0.6 percent (1,154 MW). The 2005 net generation additions by resource type are presented in the following table.

2005 Net Generation Additions (Summer Capability - MW)

Hydro – Conventional	-4,262
Hydro - Pumped Storage	51
Steam – Coal	-134
Steam – Oil	-276
Steam – Gas	-829
Nuclear	0
Combustion Turbine	707
Combined Cycle	2,910
Geothermal	20
Internal Combustion	5
Other	654
Total	-1,154

Figure 3 graphically portrays the mix of existing WECC generation as of January 1, 2006, and Table 11 on page 33, summarizes the existing generation by type and area.

Figure 4 and Table 12 on page 34; indicate the generation additions by type and area that are planned during the ten-year period. Table 13 indicates the annual generation additions by type and year while Figure 5 portrays ten years of historical and planned generation additions. Table 14 and Figure 6 depict the year 2015 generation composite planned for the WECC region.

The generation additions data and the generation composite data for the year 2015 reflect the net changes after adjusting for retirements and reratings..

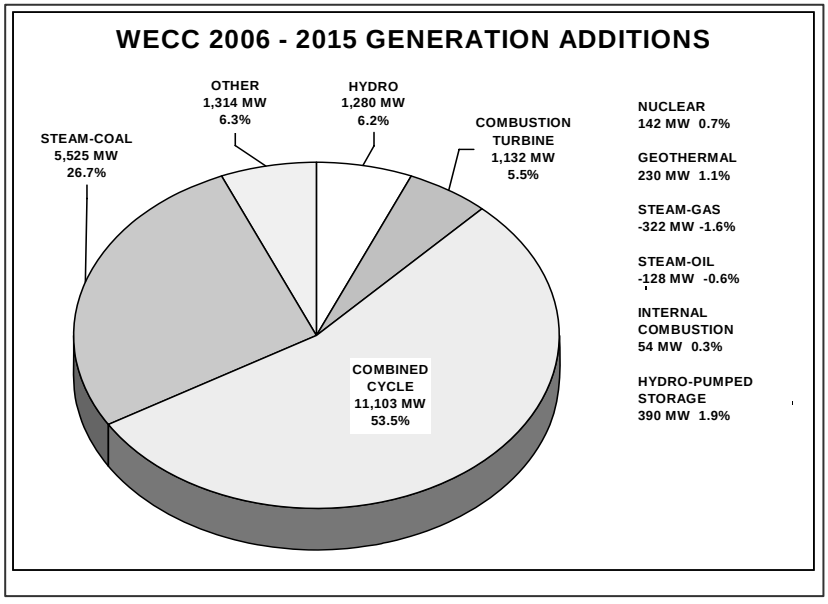
Independent power producer generation additions represent a significant percentage of the total generating capability additions projected through the next ten years, and they will account for 32.5 percent of the region's total resources by the year 2015.

Almost 60 percent of all of the projected generating capability increase during the next ten years involves natural gas-fired installations. The WECC region presently has adequate fuel supplies for the summer period. However, as demonstrated by California's experience in 2000, natural gas-fired generation may be subject to uncertainties during periods of unstable natural gas prices.

The graph on page 24, presents for the entire WECC region, the reported reserve margin and the portion of the reserve margin that is due to committed generation additions, i.e., generation that is under construction or in testing (9,952 MW) less retirements (2,053 MW). Unlike the graphs on page 25, planned purchases/sales are not included in the WECC reserve margin as planned purchases may largely reflect effective utilization of demand diversity internal to the WECC region. This diversity, which is estimated to exceed 10,000 MW, is largely due to the northern portions of WECC experiencing maximum peak demands in the winter while the southern portion experiences maximum peak demands in the summer. The graph also presents a planning reserve that is based on the sum of the planning reserves reported for the subregions.

By 2011, the reserve margin less uncommitted generation additions line drops to near the planning reserve of about 14 percent. This indicates that it is desirable that at least a portion of the 18,845 MW of reported uncommitted gross generation additions (excluding 3,642 MW of derates and unassociated retirements) be constructed in addition to the 9,952 MW of generation presently under construction or in testing. The margin graphic for the Rocky Mountain Power Area and the California-Mexico Power Area, presented on the next page, indicate that additional committed resources, either from new internal plants or increased imports from other areas, are needed as early as 2006 to meet the reported planning reserve.

The reported margin line does not drop below the planning reserve line during the ten-year



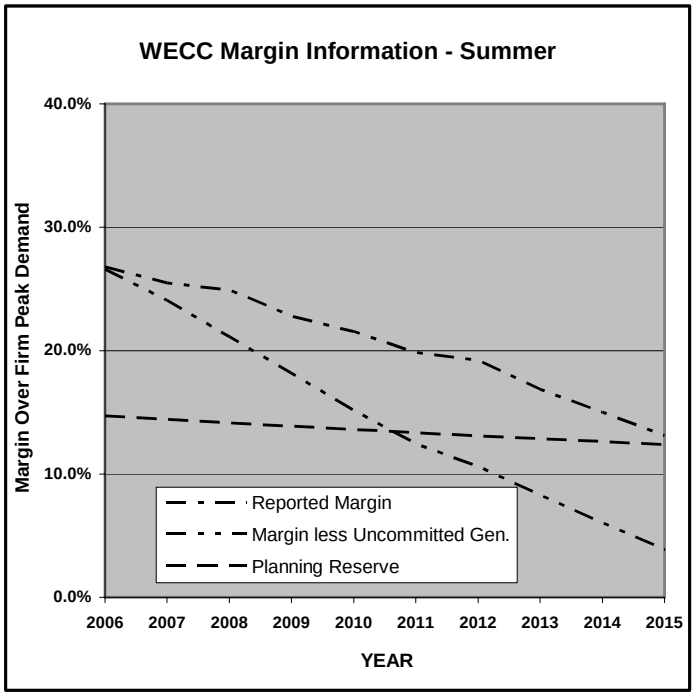
period. This indicates an adequacy in planned generation additions if loads grow as predicted and significant plant retirements beyond those already reported do not occur. Since gas-fired power plants can be built in a 24 to 36 month time frame, the reported generation additions beyond the 2006-2007 period may exclude significant amounts of new generation under consideration by developers. Although there may have been some plant construction cancellations and deferrals announced subsequent to January 1, 2006, it is expected that open-market forces will facilitate a balance between future resource needs and the construction of new generation.

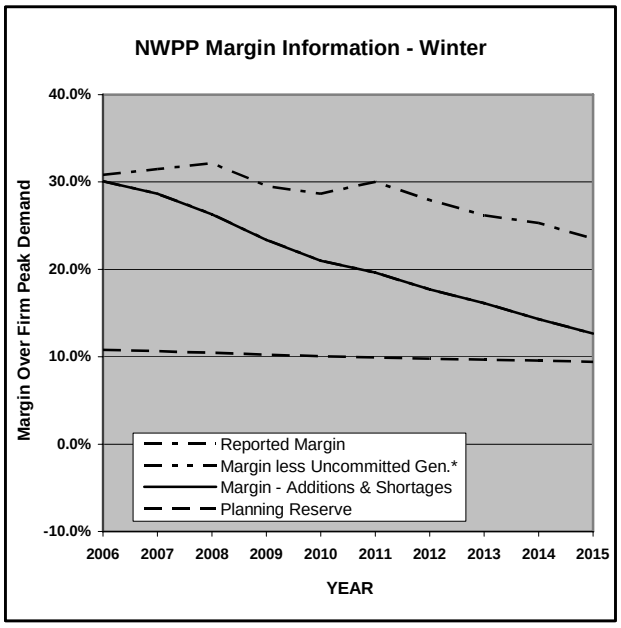
The preceding discussion should be viewed as a general indication of potential generation additions opportunities. It should not be viewed as a resource adequacy assessment as numerous factors have not been addressed. Some significant additional factors include:

- Transmission constraints – individual load serving entities may not be able to import adequate capacity from external systems.
- Weather extremes – a widespread winter cold spell or summer hot spell would significantly increase firm peak demands.
- Equipment outages – excessive scheduled maintenance and/or forced outages could result in significant capacity shortfalls.
- Forecast uncertainty – firm peak demand increases may exceed or fall short of forecasts.
- Voltage support – local area voltage support inadequacy would create unexpected transmission constraints.

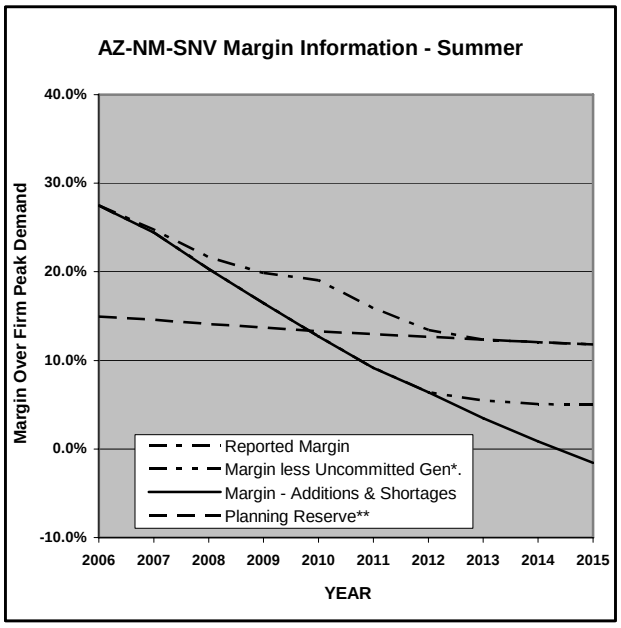
WECC's generation additions information is a summary of generation resource acquisition plans reported by entities within WECC. Some entities also report capacity acquisition needs in excess of the reported generation additions. These additional capacity resource needs may be fulfilled through purchases of excess capacity from other systems or through contracts with presently unidentified suppliers. Entities may also report planned capacity sales to presently unidentified purchasers. The generation and firm transfers projections presented in this report for the four major areas within WECC exclude these additional capacity acquisition and/or sales plans.

The graphs on the next page present the reported reserve margins, the portions of the reserve margins that are due to committed generation additions, and the portions of the reserve margins that are due to purchases of excess capacity from other systems or through contracts with presently unidentified suppliers (planned purchases) for the four major areas within WECC.

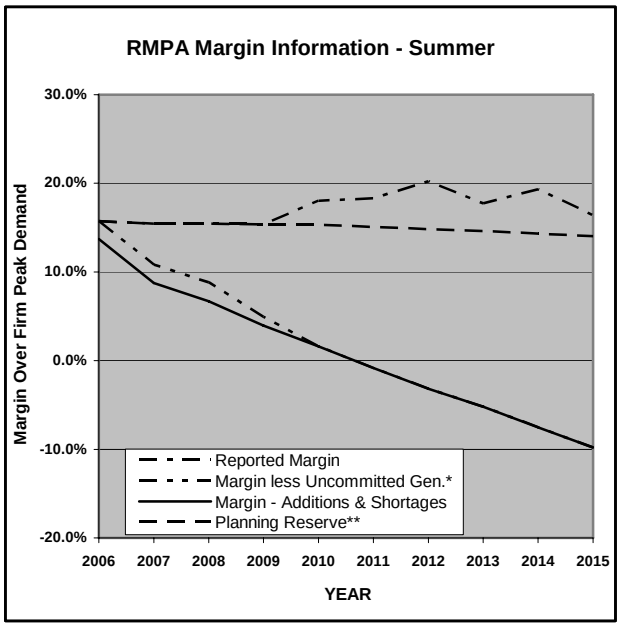




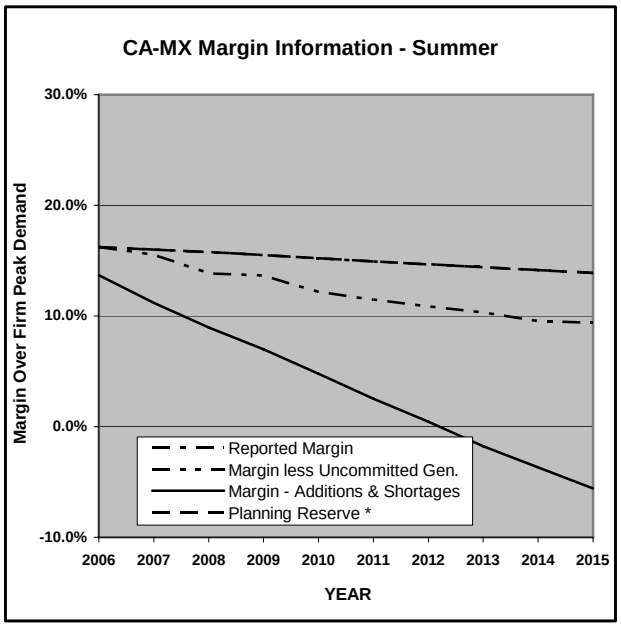
* Margin less Uncommitted Gen. equals Margin - Additions & Shortages



* Margin less Uncommitted Gen. = Margin - Additions & Shortages before 2013
**Planning Reserve = Reported Margin from 2013 to 2015



* Margin less Uncommitted Gen. = Margin - Additions & Shortages before 2013
** Planning Reserve = Reported Margin from 2013 to 2015



* Planning Reserve = Reported Margin from 2013 to 2015

Load responsibility equals the firm peak demand plus firm exports less firm imports.

The planning reserve depicted above is a summation of control area capability in excess of load responsibility to provide an acceptable operating margin plus additional capacity to cover contingencies such as forced outages and weather extremes.

Hydroelectric energy constraints must be considered in evaluating resource adequacy.

Explanatory Notes
(for Figures 1, 7, 8, 9, and 10)

The increase portrayed for the entire WECC region "Generation and Firm Transfers" from 2001 to 2002 as shown in Figure 1 reflects a significant increase in new generating plants.

The values portrayed for the Northwest Power Pool Area (NWPP) "Generation and Firm Transfers" shown in Figure 8 show the values having both up-and-down trends. This is largely due to the month that the peak occurred in during that winter season. The NWPP usually peaks in the winter season (Dec. – Feb.), but the net firm transfers in December are usually small net imports, but in January and February they are large net exports.

The increases portrayed for the Rocky Mountain Power Area "Generation and Firm Transfers" from 2001 to 2002 shown in Figure 8 is largely due to increases in new generating plants. The decrease from 1998 to 1999 reflects the transfer of some federal hydroelectric resources from the WACM to the WALC control area.

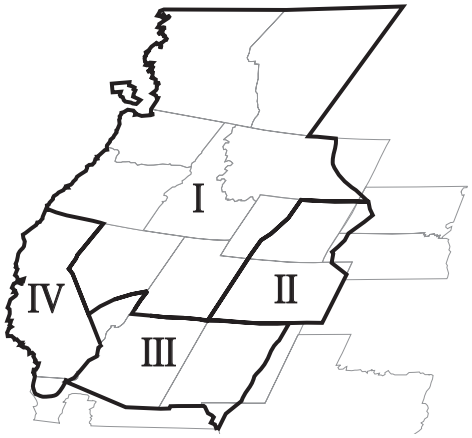
The increase portrayed for the Arizona-New Mexico-Southern Nevada Power Area "Generation and Firm Transfers" from 1998 to 1999 as shown in Figure 9 is primarily due to the transfer of some federal hydroelectric resources from the WACM to the WALC control area. The increases from 2001 to 2002 and from 2002 to 2003 reflect a significant increase in new generating plants.

The decrease portrayed for the California-Mexico Power Area "Generation and Firm Transfers" from 1996 to 1997 as shown in Figure 10 is due to reduced firm imports. The increases from 1999 to 2000 and from 2000 to 2001 reflect decreased peak demands. The increase from 2001 to 2002 reflects decreased plant unavailability and new generating plants. The decrease from 2002 to 2003 is primarily due to reduced firm imports.

WECC Region

Reporting Areas

I Northwest Power Pool Area (NWPP)
II Rocky Mountain Power Area (RMPA)
III Arizona-New Mexico-Southern Nevada Power Area (AZ/NM/SNV)
IV California-Mexico Power Area (CA/MX)



Independent Power Producers/Qualified Facilities, and Marketers

AES Corporation, The	AES
Allegheny Energy Supply Company, LLC	AESC
American Wind Energy Association Company, LLC	AWEA
Automated Power Exchange, Inc.	APX
Bonneville Power Administration - PBL	BPAP
California British Columbia Transmission	CBC
Calpine Corporation	CALP
Cargill Power Markets, LLC	CRGL
CE Obsidian Energy	CEOE
Cinergy Services, Inc.	CINE
Constellation Energy Commodities Group, Inc.	CCG
Duke Energy North America, LLC	DENA
Duke Energy Trading and Marketing, LLC	DETM
Dynegy Power Corp.	DYN
Economic Insight	ECON
Edison Mission Marketing & Trading	EMMT
Energy Northwest	ENW
ENMAX Corporation	ENMX
EPCOR Merchant and Capital (US) Inc.	EMCU
EPCOR Merchant and Capital L.P.	EMC
FPL Energy LLC	FPLE
Geo-Energy Partners-1983 Ltd.	GEO
Gila Bend Power Partners, LLC	GBPP
Harquahala Generating Company, LLC	HGC
Hunt Power, L.P.	HPLP
IGI Resources, Inc.	IGI
Merryll Lynch Commodities, Inc.	MLCI
Mirant meritas, Inc.	MIR
Montana Alberta Tie Ltd.	MATL
National Energy & Gas Transmission, Inc.	NEGT
National Renewable Energy Laboratory	NREL
North American Power Group, Ltd.	NAPG
NRG Power Marketing, Inc.	NRG
Oak Creek Energy Systems, Inc.	OCES
PacifiCorp - Merchant Function	PACM
Panda Energy International, Inc.	PAND
Panda Gila River, L.P.	PGR
Peabody Energy Corporation	PBEC
Pinnacle West Energy Corporation	PWEC
Powerex	PWX
PPL EnergyPlus, LLC	PPLE
PPL Montana, LLC	PPLM
PPM Energy, Inc.	PPM
Reliant Energy, Incorporated	REI
RES-North America	RES
Saracen Merchant Energy L.P.	SME
Sempra Energy Resources	SER
Sempra Energy Trading Corp.	SETC
Shell Trading	STGP
Southwestern Power Group II, LLC	SWPG
SUEZ Energy Marketing NA, Inc.	SUEZ
Tenaska	TNSK
TransCanada Energy Ltd.	TCP
Wellhead Electric Company, Inc.	WECI
Williams Power Company, Inc.	WEMT

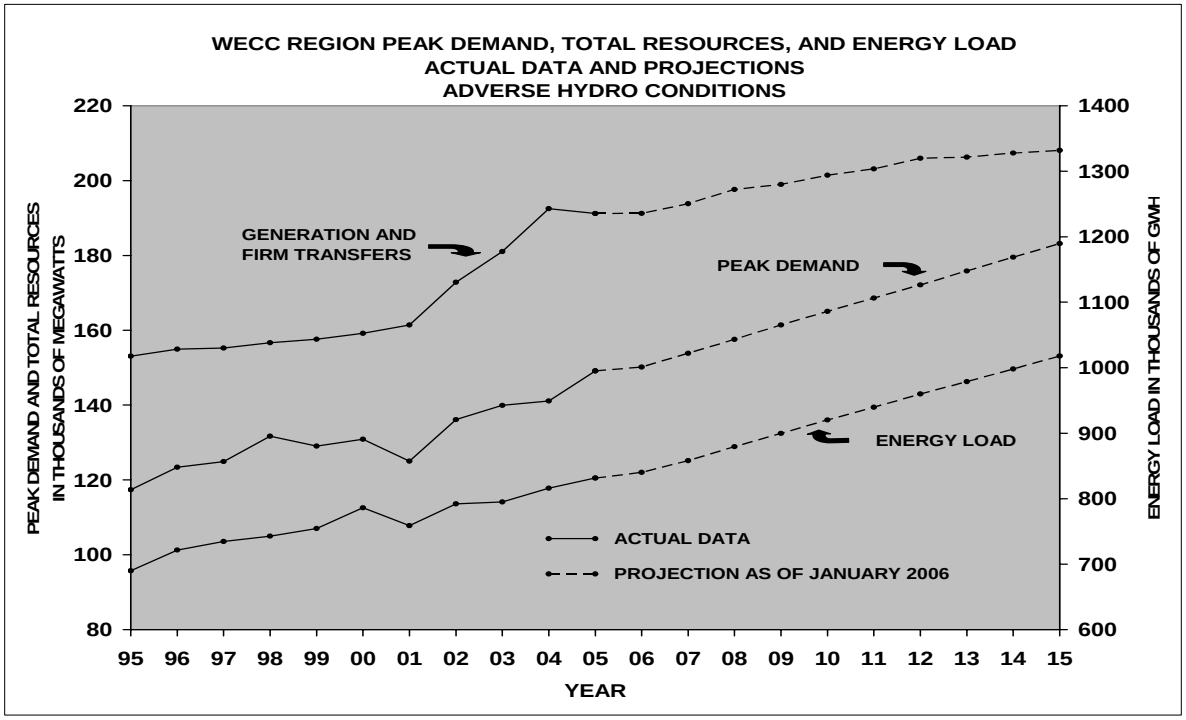


Figure 1

Table 3 - WECC Actual Loads and Resources for 2005

PEAK DEMAND – MW		JAN	FEB	MAR	APR	MAY	JUN
Loads -	Firm	121110	113931	106892	106083	121648	130705
	Interruptible & Load Mgt	2442	2445	2454	2466	2317	2765
	Total	123552	116376	109346	108549	123965	133470
	Forecast Deviation - %	-0.1	-3.1	-5.7	-6.4	-1.3	-2.4
Generation -	Hydro	61124	61120	60939	60538	61257	63658
	Thermal	114925	114831	114970	114536	115132	119942
	Other	6031	6032	6038	6050	6084	5816
	Total	182080	181983	181947	181124	182473	189416
Total Unavailable Generation *		14125	15709	15053	20487	19980	12679
Net Firm Transfers - MRO		-15	6	16	-28	34	92
	SPP **	-727	-727	-544	-577	-577	-577
	Total Net Firm Transfers	-742	-721	-528	-605	-543	-485
Net Generation & Firm Transfers		168697	166995	167422	161242	163036	177222
Margin Over Firm Loads - MW		47587	53064	60530	55159	41388	46517
Margin Over Firm Loads - Percent		39.3	46.6	56.6	52.0	34.0	35.6
ENERGY - GWH							
Total Load		70747	61877	64994	62358	66834	69122
	Forecast Deviation - %	-1.3	-3.8	-4.0	-3.2	-1.5	-2.5

PEAK DEMAND – MW		JUL	AUG	SEP	OCT	NOV	DEC	
Loads -	Firm	146552	140660	129028	117866	118945	126812	
	Interruptible & Load Mgt	2695	2739	2687	2255	2248	2122	
	Total	149147	143399	131715	120121	121193	128934	
	Forecast Deviation - %	2.0	-1.6	-3.2	-2.6	0.8	1.2	
Generation -	Hydro	64376	63882	63917	61136	60880	61491	
	Thermal	120499	120580	120772	116933	117424	117969	
	Other	5806	5833	5778	6027	6047	6110	
	Total	190681	190295	190467	184096	184351	185570	
Total Unavailable Generation *		11501	12308	12590	16768	20092	14799	
Net Firm Transfers - MRO **		77	75	106	12	-70	-36	
	SPP **	-577	-577	-577	-444	-577	-577	
	Total Net Firm Transfers	-500	-502	-471	-432	-647	-613	
Net Generation & Firm Transfers		179680	178489	178348	167760	164906	171384	
Margin Over Firm Loads - MW		33128	37829	49320	49894	45961	44572	
Margin Over Firm Loads - Percent		22.6	26.9	38.2	42.3	38.6	35.1	
ENERGY - GWH								TOTAL
Total Load		80419	78462	68564	66919	67217	74057	831570
	Forecast Deviation - %	3.3	0.1	-3.6	-1.8	0.5	2.1	-1.2

* Includes Maintenance, Forced Outages, and Inoperable Capability.
** Minus (-) indicates transfer into WECC Region.

Table 4 - Projected Peak Demand Average Annual Compound Growth Rates - Percent (Adverse Hydro Conditions)

	1995 - 2005	1996 - 2006	1997 - 2007	1998 - 2008	1999 - 2009	2000 - 2010	2001 - 2011	2002 - 2012	2003 - 2013	2004 - 2014	2005 - 2015
WECC – Total	1.6	1.4	1.6	1.5	2.1	2.2	2.5	1.9	2.0	2.5	2.1
Northwest Power Pool Area	1.2	1.6	1.9	1.1	2.1	2.0	2.5	2.5	1.1	1.7	1.8
Rocky Mountain Power Area	1.7	2.0	2.0	2.2	2.7	2.0	2.3	1.7	2.0	2.6	2.4
Arizona-New Mexico-So. Nevada Power Area*	1.9	2.2	2.9	2.5	3.6	3.3	3.1	3.0	3.0	3.2	2.7
California-Mexico Power Area*	1.4	1.3	0.9	1.3	1.8	2.6	2.4	2.1	2.2	2.5	2.1

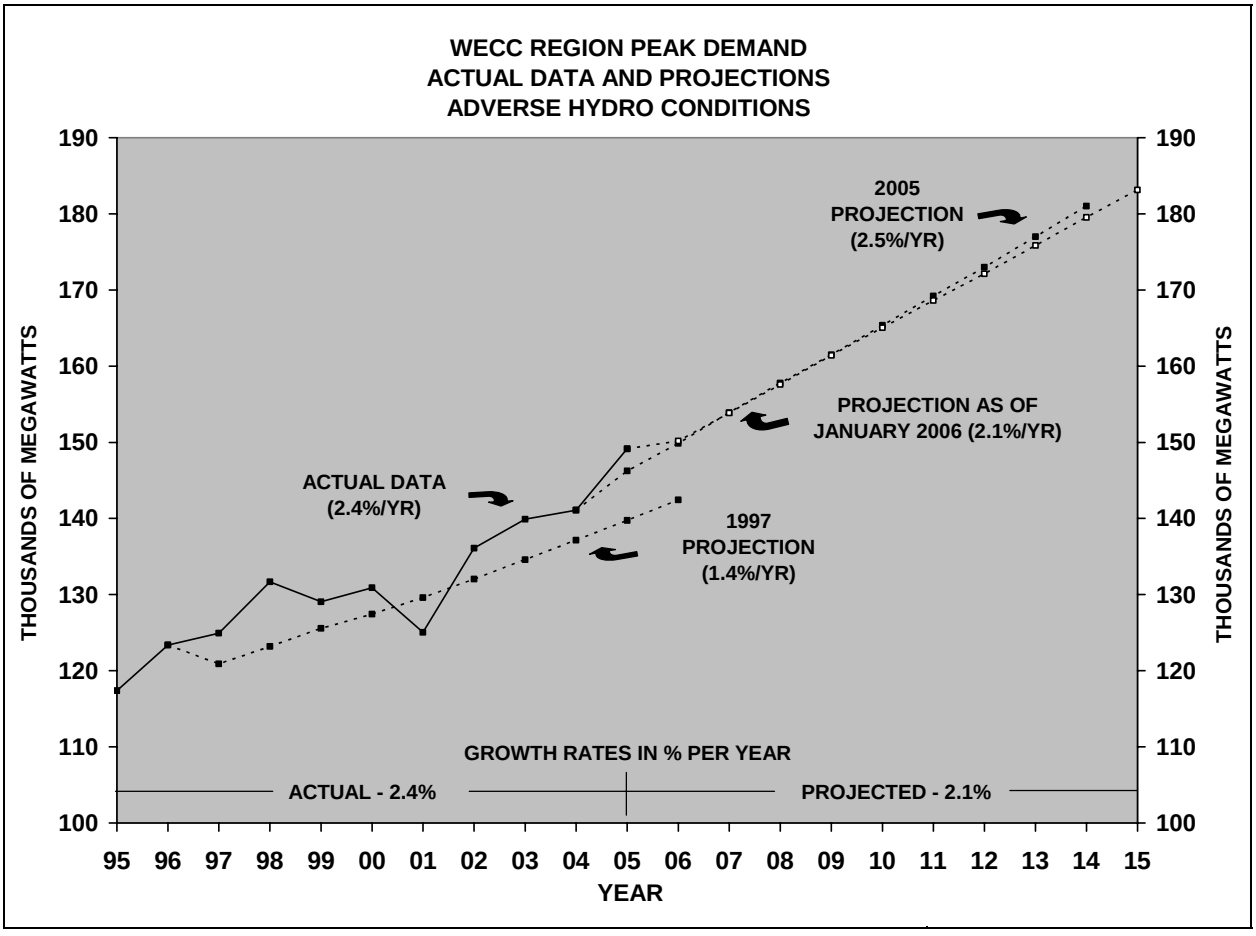


Figure 2

Table 5 – Actual Peak Demand Growth Rates – Percent
(Actual Hydro Conditions)

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
WECC – Total	1.3	5.1	1.3	5.4	-2.0	1.4	-4.5	8.9	2.8	0.8	5.7
Northwest Power Pool Area	8.7	-2.5	-0.4	8.4	-6.6	2.1	-8.1	-0.4	13.5	0.5	3.2
Rocky Mountain Power Area	4.5	1.9	7.1	0.6	-4.2	12.4	8.6	6.0	6.0	-0.8	6.6
Arizona-New Mexico-So. Nevada Power Area*	4.4	4.5	1.8	7.4	-2.3	8.9	7.5	3.7	5.5	0.3	9.1
California-Mexico Power Area*	-0.7	4.2	3.8	4.2	-4.1	-3.6	-5.6	8.0	1.6	5.4	2.6

*The 1995 through 1996 projected peak demand growth rate percentages include the Southern Nevada reporting area data in the California-Mexico Power Area data.

Table 6 – Actual Energy Load Growth Rates – Percent
(Actual Hydro Conditions)

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
WECC – Total	0.3	4.6	1.8	1.1	1.6	4.2	-3.5	4.4	0.4	2.6	1.9
Northwest Power Pool Area	0.6	5.0	-0.7	3.3	1.8	1.6	-8.6	5.7	-0.6	2.0	3.9
Rocky Mountain Power Area	3.3	1.2	7.2	2.1	-3.7	11.2	5.8	3.0	1.3	0.7	3.5
Arizona-New Mexico-So. Nevada Power Area*	1.9	8.0	4.0	-1.2	-0.4	7.7	6.6	3.9	4.2	2.0	2.9
California-Mexico Power Area*	-1.3	3.4	3.3	-0.9	3.0	5.1	-2.4	3.2	-0.2	4.1	-1.3

*The 1995 through 1996 projected peak demand growth rate percentages include the Southern Nevada reporting area data in the California-Mexico Power Area data.

Table 7– WECC Estimated Peak Demands, Resources, and Reserves 2006 - 2015

	SUMMER PEAK							Adverse Hydro Conditions		
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Month	JUL	JUL	JUL	JUL	JUL	JUL	JUL	JUL	JUL	JUL
Loads – Firms	147104	150752	154468	158264	161899	165453	168951	172682	176367	179973
Int. & Load Mgt	3073	3096	3119	3146	3169	3171	3172	3173	3174	3175
Total - MW	150177	153848	157587	161410	165068	168624	172123	175855	179541	183148
Growth from Previous Yr. - %	0.7	2.4	2.4	2.4	2.3	2.2	2.1	2.2	2.1	2
Generation ± Transfers - MW	191220	193835	197609	198965	201429	203133	205975	206248	207333	208086
Maint./Inoperable Cap. - MW	4686	4660	4671	4631	4639	4858	4590	4471	4480	4477
Reserve Capability										
MW	39430	38423	38470	36070	34891	32822	32434	29095	26486	23636
Percent of Firm Peak Demand	26.8	25.5	24.9	22.8	21.6	19.8	19.2	16.8	15	13.1

	WINTER PEAK							Adverse Hydro Conditions		
	06-07	07-08	08-09	09-10	10-11	11-12	12-13	13-14	14-15	15-16
Month	DEC	DEC	DEC	DEC	DEC	DEC	DEC	DEC	DEC	DEC
Loads – Firms	127394	129995	132840	135909	138716	141439	144172	146961	149708	152626
Int. & Load Mgt	2240	2242	2245	2250	2254	2256	2257	2258	2259	2260
Total - MW	129634	132237	135085	138159	140970	143695	146429	149219	151967	154886
Growth from Previous Yr. - %	0.5	2.0	2.2	2.3	2.0	1.9	1.9	1.9	1.8	1.9
Generation ± Transfers - MW	187174	190024	193861	195254	197712	199384	201725	202597	203080	203833
Maint./Inoperable Cap. - MW	8042	7140	7386	7364	7499	7810	7131	7106	7132	6984
Reserve Capability										
MW	51738	52889	53635	51981	51497	50135	50422	48530	46240	44223
Percent of Firm Peak Demand	40.6	40.7	40.4	38.2	37.1	35.4	35.0	33.0	30.9	29.0

Table 8 - Projected Peak Demand Growth Rates - Percent (Adverse Hydro Conditions)

											Average Annual Compound Growth Rate
		2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2005-2015
WECC - Total	Summer	0.7	2.4	2.4	2.4	2.3	2.2	2.1	2.2	2.1	2.0	2.1
	Winter	0.5	2.0	2.2	2.3	2.0	1.9	1.9	1.9	1.8	1.9	1.9
Northwest Power	Summer	-0.6	2.4	2.5	2.5	2.0	2.0	1.9	2.0	1.9	1.7	1.8
Pool Area	Winter	-0.3	1.9	1.7	2.4	1.8	1.5	1.7	1.4	1.6	1.5	1.5
Rocky Mountain	Summer	2.1	3.7	2.0	2.6	2.2	2.1	2.0	2.1	2.5	2.4	2.4
Power Area	Winter	1.6	3.1	1.8	2.1	2.0	2.0	2.0	2.0	2.3	2.2	2.1
Arizona-New Mexico-So.	Summer	1.1	2.9	3.3	3.3	3.3	2.8	2.6	2.8	2.6	2.5	2.7
Nevada Power Area	Winter	6.2	2.9	3.0	3.2	2.6	2.5	2.4	2.5	2.5	2.2	3.0
California-Mexico	Summer	2.9	2.0	2.0	1.9	2.0	2.0	2.0	2.0	1.9	1.9	2.1
Power Area	Winter	1.5	2.0	2.0	2.0	1.9	2.0	2.0	2.0	2.0	2.0	1.9

Table 9 - Summary of Projected Energy Loads - GWh
(Adverse Hydro Conditions)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
WECC – Total	840240	858067	879507	899596	920356	939604	959976	978761	998133	1017955
Northwest Power Pool Area	366166	372725	382146	390391	398758	406221	414611	421605	428805	436257
Rocky Mountain Power Area	60102	61754	63241	64709	65926	67289	68656	69992	71566	73025
Arizona-New Mexico-So. Nevada Power Area	129767	133549	137968	142198	147083	151050	155115	159088	163044	167121
California-Mexico Power Area	284205	290039	296152	302298	308589	315044	321594	328076	334718	341522

Table 10 - Projected Energy Load Growth Rates - Percent
(Adverse Hydro Conditions)

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	Average Annual Compound Growth Rate 2005-2015
WECC – Total	1.0	2.1	2.5	2.3	2.3	2.1	2.2	2.0	2.0	2.0	2.0
Northwest Power Pool Area	1.5	1.8	2.5	2.2	2.1	1.9	2.1	1.7	1.7	1.7	1.9
Rocky Mountain Power Area	1.5	2.7	2.4	2.3	1.9	2.1	2.0	1.9	2.2	2.0	2.1
Arizona-New Mexico-So. Nevada Power Area	2.6	2.9	3.3	3.1	3.4	2.7	2.7	2.6	2.5	2.5	2.8
California-Mexico Power Area	-0.3	2.1	2.1	2.1	2.1	2.1	2.1	2.0	2.0	2.0	1.8

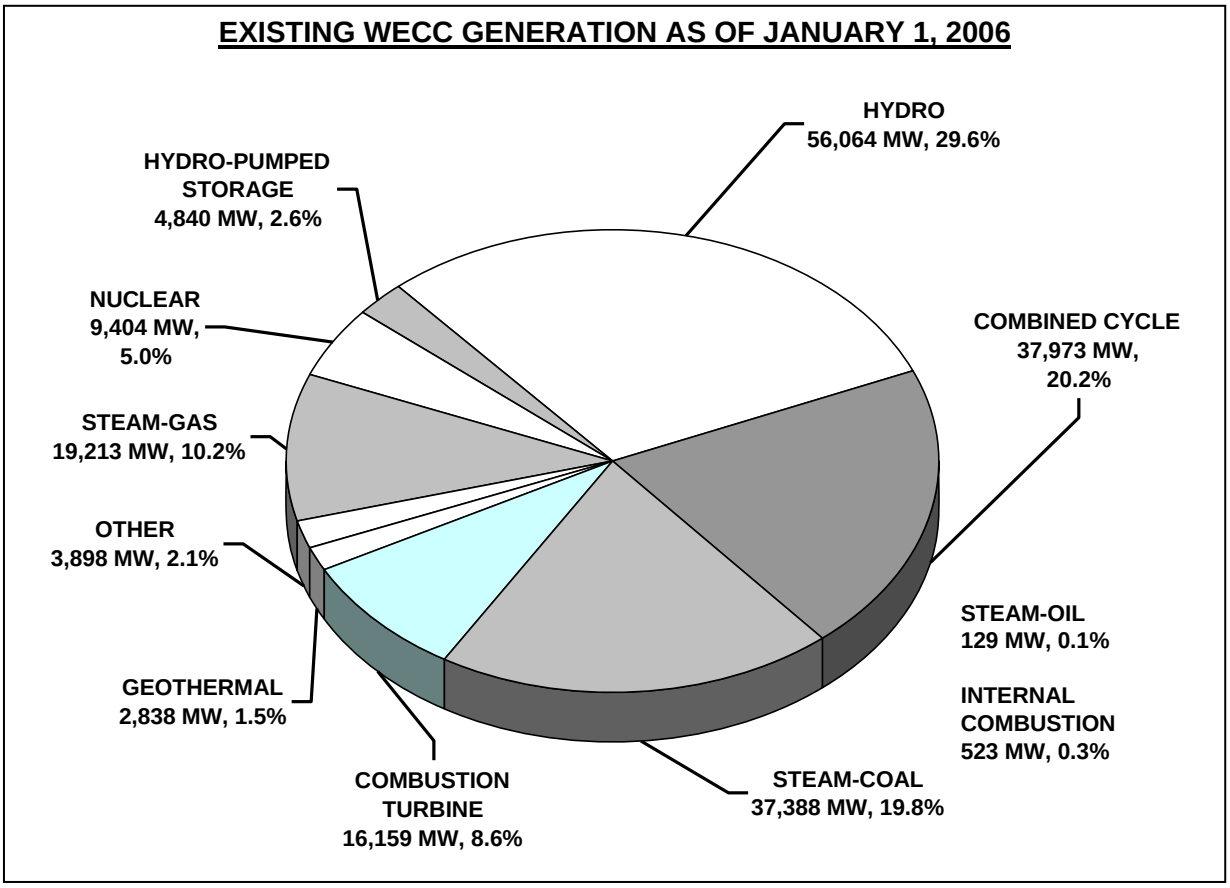


Figure 3

Table 11 - Existing Generating Capability as of January 1, 2006
(Summer Capability - MW)

Generation Type	Northwest Power Pool Area	Rocky Mountain Power Area	Arizona New Mexico So. Nevada Power Area	California Mexico Power Area	WECC Total	% of Total
Hydro - Conventional	42965	893	3793	8413	56064	29.6
Hydro - Pumped Storage	240	410	245	3945	4840	2.6
Steam - Coal	17523	6241	9863	3761	37388	19.8
Steam - Oil	0	1	128	0	129	0.1
Steam - Gas	1953	235	2234	14791	19213	10.2
Nuclear	1150	0	3804	4450	9404	5.0
Combustion Turbine	4154	1927	2927	7151	16159	8.6
Combined Cycle	7491	2598	13688	14196	37973	20.2
Geothermal	150	0	450	2238	2838	1.5
Internal Combustion	215	263	4	41	523	0.3
Other	1112	24	126	2636	3898	2.1
Total	76953	12592	37262	61622	188429	100.0
Total Percent of WECC	40.8	6.7	19.8	32.7	100.0	

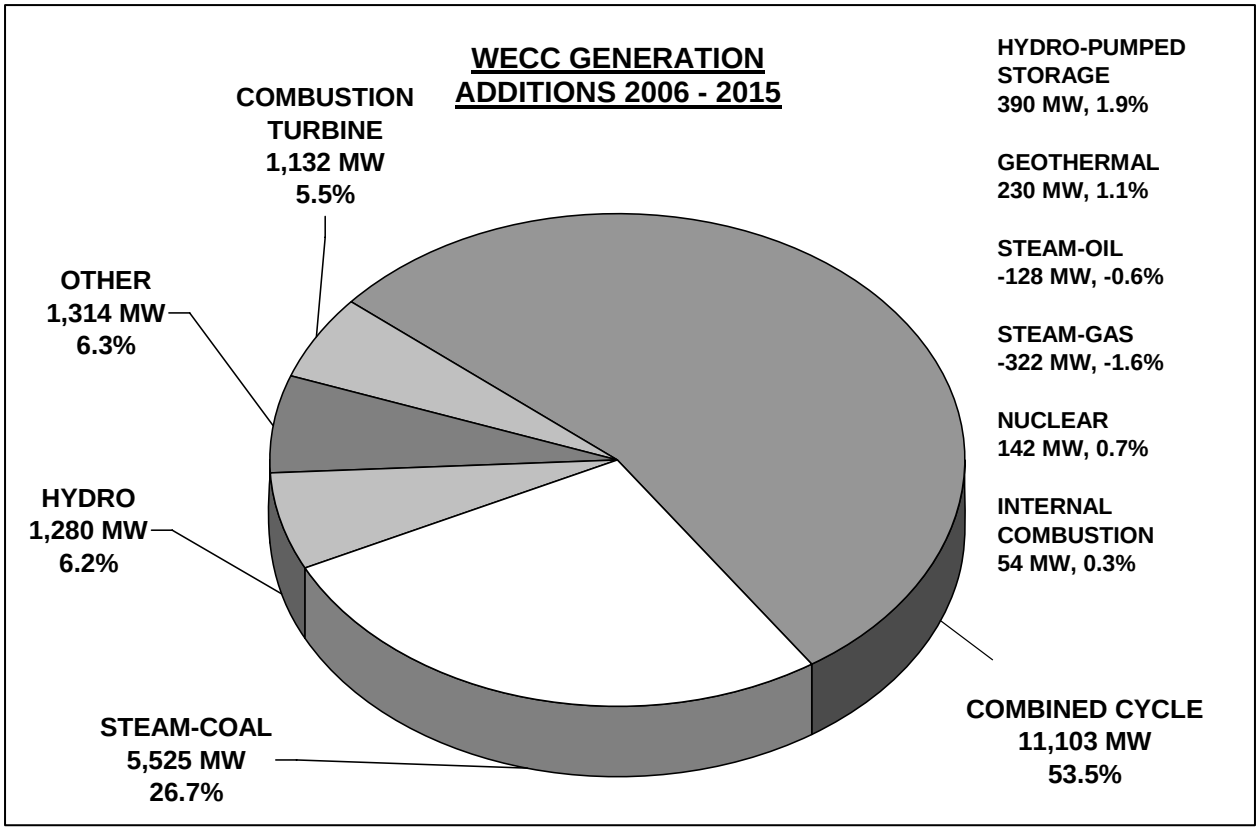


Figure 4

Table 12 - Summary of Generation Additions 2006 – 2015 by Area (Summer Capability - MW)

Generation Type	Northwest Power Pool Area	Rocky Mountain Power Area	Arizona New Mexico So. Nevada Power Area	California Mexico Power Area	WECC Total	% of Total
Hydro - Conventional	1278	0	0	2	1280	6.2
Hydro - Pumped Storage	0	0	0	390	390	1.9
Steam - Coal	3855	2415	835	-1580	5525	26.7
Steam - Oil	0	0	-128	0	-128	-0.6
Steam - Gas	15	0	-174	-163	-322	-1.6
Nuclear	0	0	142	0	142	0.7
Combustion Turbine	550	534	19	29	1132	5.5
Combined Cycle	1956	646	4171	4330	11103	53.5
Geothermal	35	0	195	0	230	1.1
Internal Combustion	54	0	0	0	54	0.3
Other	1068	84	10	152	1314	6.3
Total	8811	3679	5070	3160	20720	100.0
Total Percent of WECC	42.4	17.8	24.5	15.3	100.0	

Table 13 - WECC Summary of Generation Additions by Year
(Summer Capability - MW)

Generation Type	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	10 Yr. Period	% of Total
Hydro - Conventional	152	16	3	42	618	447	0	0	0	0	1278	6.1
Hydro - Pumped Storage	0	0	0	0	0	0	0	0	390	0	390	1.8
Steam - Coal	-1033	80	900	268	1180	885	1925	600	0	750	5555	26.3
Steam - Oil	0	0	0	-48	0	0	-80	0	0	0	-128	-0.6
Steam - Gas	-163	15	0	0	0	0	0	-48	-127	0	-323	-1.5
Nuclear	71	0	71	0	0	0	0	0	0	0	142	0.7
Combustion Turbine	149	815	253	70	70	-140	0	70	-70	0	1217	5.8
Combined Cycle	4408	1386	2071	1152	755	541	489	250	288	0	11340	53.7
Geothermal	25	10	170	0	0	25	0	0	0	0	230	1.1
Internal Combustion	54	0	0	0	0	0	0	0	0	0	54	0.3
Other	385	517	377	2	1	52	2	0	0	0	1336	6.3
Total	4048	2839	3845	1486	2624	1810	2336	872	481	750	21091	100.0

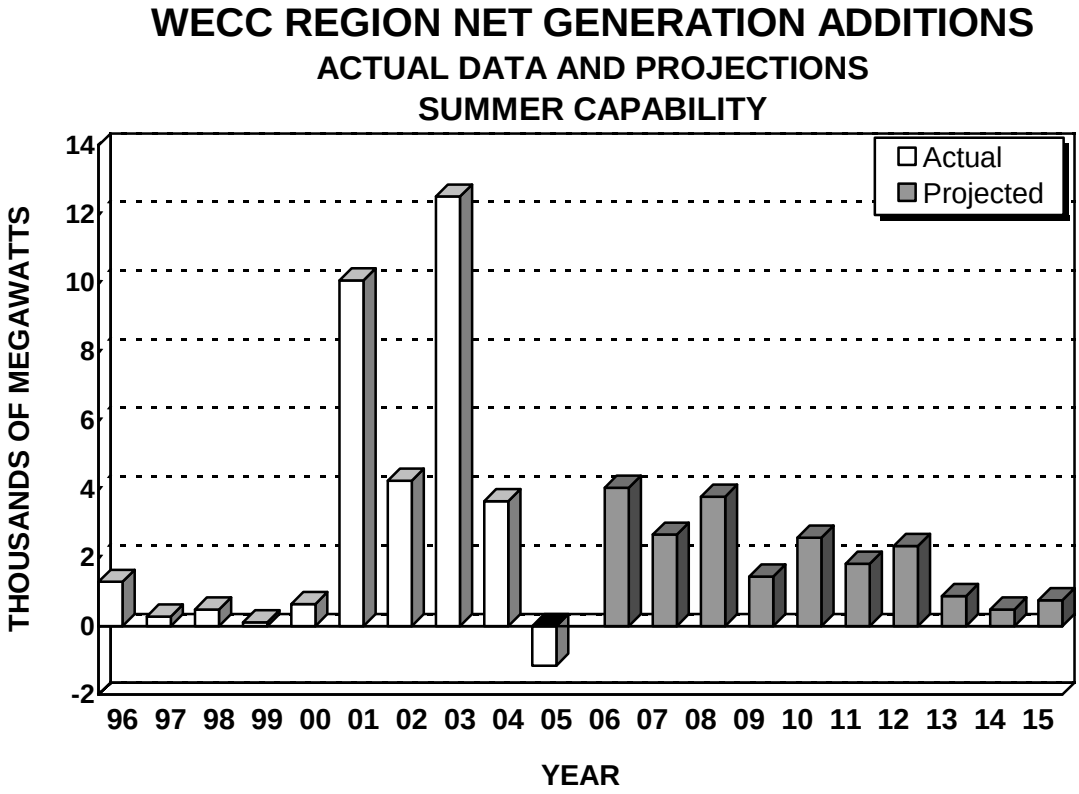


Figure 5

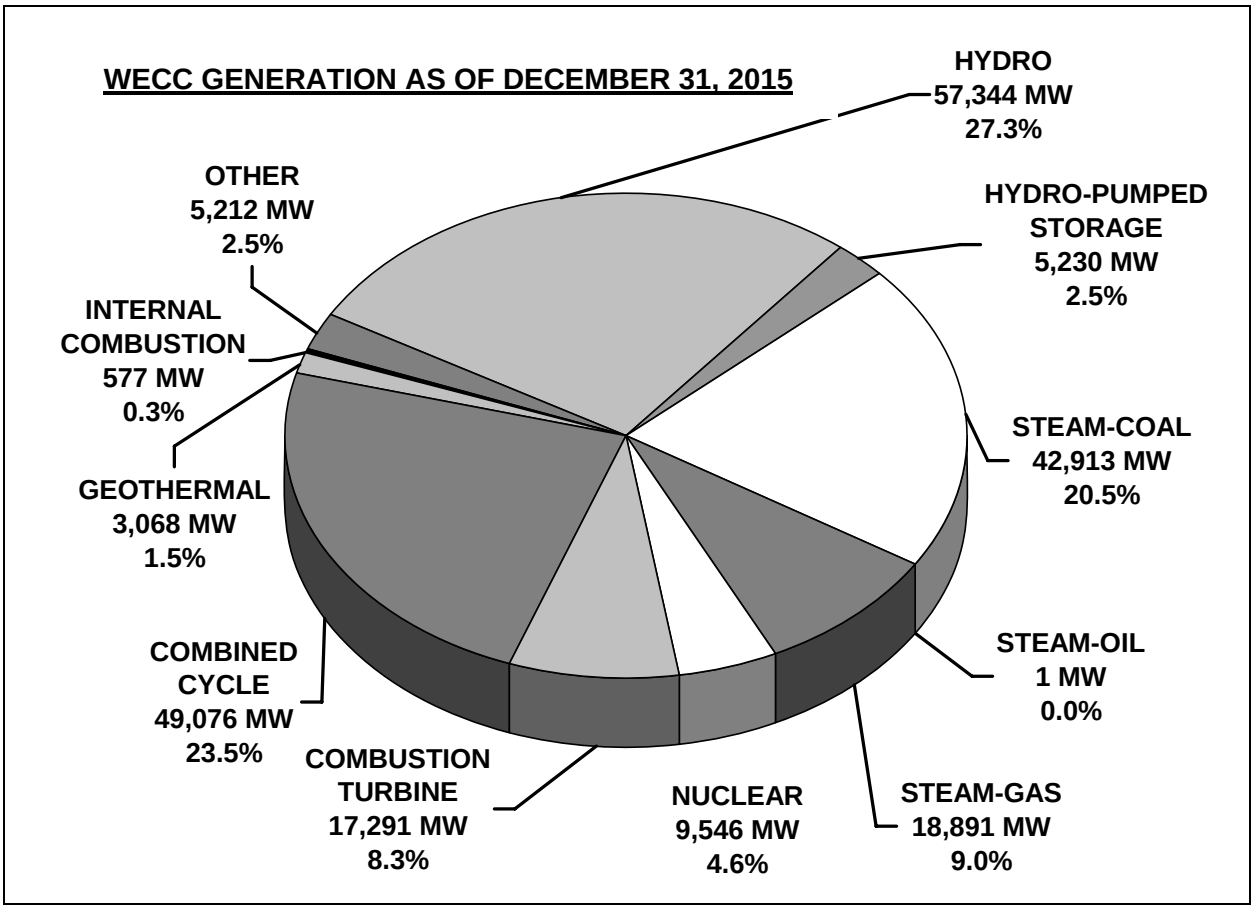
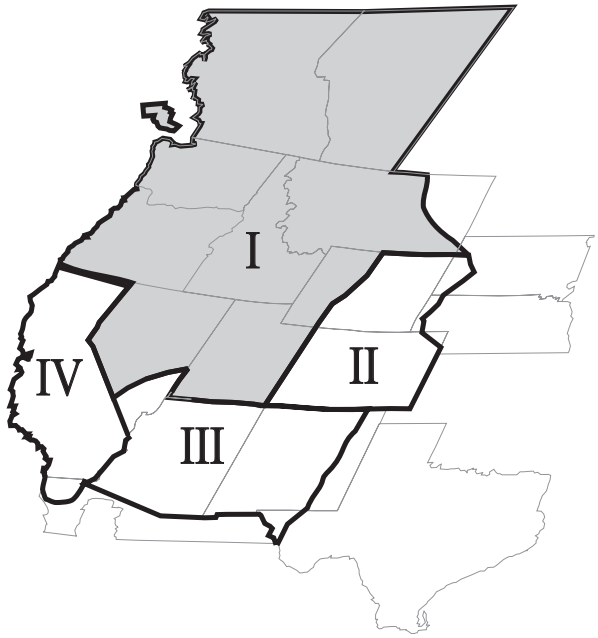


Figure 6

Table 14 - Generating Capability as of December 31, 2015
(Summer Capability - MW)

Generation Type	Northwest Power Pool Area	Rocky Mountain Power Area	Arizona New Mexico So. Nevada Power Area	California Mexico Power Area	WECC Total	% of Total
Hydro - Conventional	44243	893	3793	8415	57344	29.6
Hydro - Pumped Storage	240	410	245	4335	5230	2.6
Steam - Coal	21378	8656	10698	2181	42913	20.5
Steam - Oil	0	1	0	0	1	0.0
Steam - Gas	1968	235	2060	14628	18891	9.0
Nuclear	1150	0	3946	4450	9546	4.6
Combustion Turbine	4704	2461	2946	7180	17291	8.3
Combined Cycle	9447	3244	17859	18526	49076	23.5
Geothermal	185	0	645	2238	3068	1.5
Internal Combustion	269	263	4	41	577	0.3
Other	2180	108	136	2788	5212	2.5
Total	85764	16271	42332	64782	209149	100.0
Percent of WECC Total	41.0	7.8	20.2	31.0	100.0	

Northwest Power Pool Area (NWPP)



U.S. Systems

Avista Corp.	AVA
Bonneville Power Administration - TBL	BPAT
Chelan County PUD No. 1	CHPD
Deseret Generation & Transmission Co-operative	DGT
Douglas County PUD No. 1	DOPD
Eugene Water & Electric Board	EWEB
Grant County PUD No. 2	GCPD
Idaho Power Company	IPC
New Transmission Development Company (A TransElect Company)	NTD
NorthWestern Energy	NWMT
PacifiCorp	PAC
Pend Oreille County PUD No. 1	POPD
Portland General Electric Company	PGE
Puget Sound Energy	PSE
Seattle Department of Lighting (Seattle City Light)	SCL
Sierra Pacific Resources Transmission	SPR
Snohomish County PUD No. 1	SNPD
Tacoma Power	TPWR
U.S.B.R. Pacific Northwest Region	USPN
U.S.B.R. Upper Colorado Region	USUC
U.S. Army Corps of Engineers (North Pacific Division)	USCE
Utah Associated Municipal Power Systems	UAMP
Utah Municipal Power Agency	UMPA
Western Area Power Administration - Billings Area	WAUW

Canadian Systems

Alberta Electric System Operator	AESO
AltaLink L.P	ALTA
ATCO Electric Ltd.	ATCO
British Columbia Hydro and Power Authority	BCHA
British Columbia Transmission Corporation	BCTC
Fortis BC	FBC
Sea Breeze Pacific Regional Transmission Systems, Inc.	SBP
TransAlta Utilities Corporation	TAUC

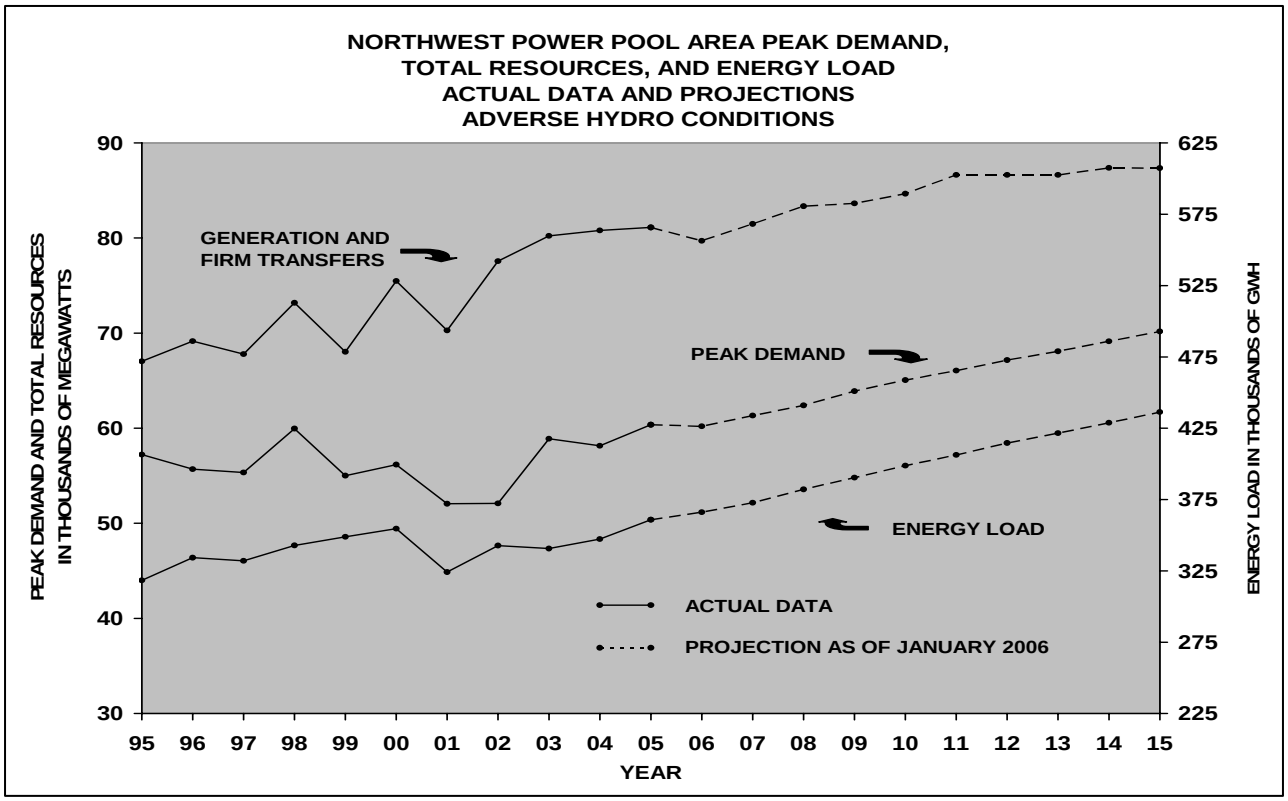


Figure 7

Table 15 - Northwest Power Pool Area Actual Loads and Resources for 2005

PEAK DEMAND – MW		JAN	FEB	MAR	APR	MAY	JUN	
Loads -	Firm	57688	54145	48606	47549	45425	48790	
	Interruptible & Load Mgt	460	460	460	460	460	460	
	Total	58148	54605	49066	48009	45885	49250	
	Forecast Deviation - %	1.2	-0.9	-5.1	-0.3	-2.2	1.1	
Generation -	Hydro	45158	45174	44983	44460	45137	46053	
	Thermal	32931	32922	32908	32901	32837	33003	
	Other	1184	1185	1179	1191	1188	1199	
	Total	79273	79281	79070	78552	79162	80255	
Total Unavailable Generation *		2231	2431	2442	4134	5053	4779	
Net Firm Transfers - MRO		104	123	128	131	129	106	
	RMPA **	-384	-385	-391	-413	-326	-334	
	AZ-NM-SNV **	-1219	-1219	-739	-559	-79	-79	
	CA-MX **	-25	-25	275	308	420	913	
	Total Net Firm Transfers	-1524	-1506	-727	-533	144	606	
Net Generation & Firm Transfers		78566	78356	77355	74951	73983	74870	
Margin Over Firm Loads - MW		20878	24211	28749	27402	28558	26080	
Margin Over Firm Loads - Percent		36.2	44.7	59.1	57.6	62.9	53.5	
ENERGY - GWH								
Total Load		33788	29393	29819	27754	27888	27955	
	Forecast Deviation - %	2.3	-0.3	-1.6	-0.1	0.0	0.8	
	Total	52698	51865	47808	47928	56054	60366	
	Forecast Deviation - %	4.0	2.9	1.1	-4.0	3.7	4.3	
Generation -	Hydro	46765	46277	46339	45132	44906	45438	
	Thermal	33022	33027	33144	32777	32823	32838	
	Other	1189	1181	1165	1168	1188	1238	
	Total	80976	80485	80648	79077	78917	79514	
Total Unavailable Generation *		4044	4320	5327	5416	4018	2884	
Net Firm Transfers - MRO		95	96	126	131	105	91	
	RMPA **	-331	-336	-296	-282	-384	-378	
	AZ-NM-SNV **	-79	-79	-79	-1219	-1219	-1219	
	CA-MX **	938	950	943	446	-102	-102	
	Total Net Firm Transfers	623	631	694	-924	-1600	-1608	
Net Generation & Firm Transfers		76309	75534	74627	74585	76499	78238	
Margin Over Firm Loads - MW		24071	24129	27279	27117	20905	18332	
Margin Over Firm Loads - Percent		46.1	46.9	57.6	57.1	37.6	30.6	
ENERGY - GWH								TOTAL
Total Load		30689	30719	27592	28830	31299	35163	360889
	Forecast Deviation - %	2.9	3.1	1.4	1.8	4.9	6.7	1.9

* Includes Maintenance, Forced Outages, and Inoperable Capability.
** Minus (-) indicates transfer into WECC Region.

Table 16 - Northwest Power Pool Area Estimated Peaks Demands, Resources, and Reserves 2006 - 2015

	SUMMER PEAK							Adverse Hydro Conditions		
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Month	JUL	JUL	JUL	JUL	JUL	JUL	JUL	JUL	JUL	JUL
Loads – Firms	51898	53148	54500	55851	57002	58161	59255	60470	61609	62669
Int. & Load Mgt	460	460	460	460	460	460	460	460	460	460
Total - MW	52358	53608	54960	56311	57462	58621	59715	60930	62069	63129
Growth from Previous Yr. - %	-0.6	2.4	2.5	2.5	2.0	2.0	1.9	2.0	1.9	1.7
Generation ± Transfers - MW	76901	78743	81146	81406	81472	82618	84482	84608	84609	85385
Maint./Inoperable Cap. - MW	2753	2727	2738	2818	2826	3045	2777	2658	2667	2664
Reserve Capability										
MW	22250	22868	23908	22737	21644	21412	22450	21480	20333	20052
Percent of										
Firm Peak Demand	47.1	43.0	43.9	40.7	38.0	36.8	37.9	35.5	33.0	32.0

Projected Average Annual Summer Compound Growth Rate (2005-2015) - 1.8%

	WINTER PEAK							Adverse Hydro Conditions		
	06-07	07-08	08-09	09-10	10-11	11-12	12-13	13-14	14-15	15-16
Month	JAN	JAN	JAN	JAN	JAN	JAN	JAN	JAN	JAN	JAN
Loads – Firms	59739	60869	61936	63434	64604	65590	66699	67628	68688	69725
Int. & Load Mgt	460	460	460	460	460	460	460	460	460	460
Total - MW	60199	61329	62396	63894	65064	66050	67159	68088	69148	70185
Growth from Previous Yr. - %	-0.3	1.9	1.7	2.4	1.8	1.5	1.7	1.4	1.6	1.5
Generation ± Transfers - MW	79712	81487	83356	83645	84659	86633	86633	86634	87386	87365
Maint./Inoperable Cap. - MW	1565	1462	1522	1479	1532	1359	1302	1282	1319	1255
Reserve Capability										
MW	18408	19156	19898	18732	18523	19684	18632	17724	17379	16385
Percent of										
Firm Peak Demand	30.8	31.5	32.1	29.5	28.7	30.0	27.9	26.2	25.3	23.5

Projected Average Annual Winter Compound Growth Rate (2005/06-2015/2016) - 1.5%

Table 17 - Northwest Power Pool Area Summary of Generation Additions (Summer Capability - MW)

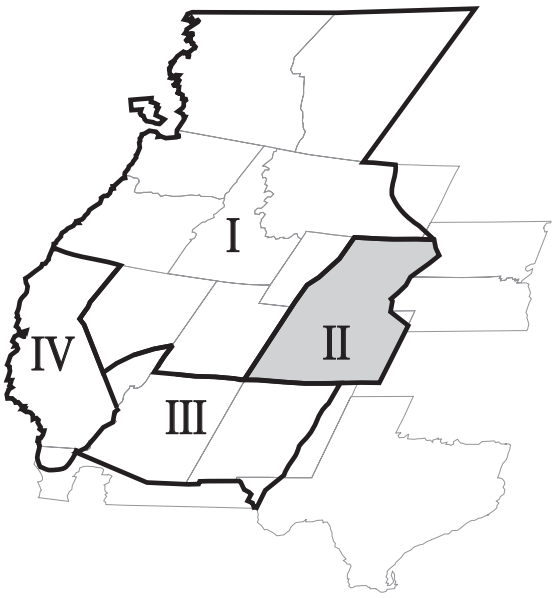
Generation Type	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	10 Yr. Period	% of Total
Hydro - Conventional	152	18	21	42	598	447	0	0	0	0	1278	14.5
Hydro - Pumped Storage	0	0	0	0	0	0	0	0	0	0	0	0.0
Steam - Coal	112	0	900	268	0	500	1325	0	0	750	3855	43.6
Steam - Oil	0	0	0	0	0	0	0	0	0	0	0	0.0
Steam - Gas	0	15	0	0	0	0	0	0	0	0	15	0.2
Nuclear	0	0	0	0	0	0	0	0	0	0	0	0.0
Combustion Turbine	119	266	165	0	0	0	0	0	0	0	550	6.2
Combined Cycle	543	899	514	0	0	0	0	0	0	0	1956	22.2
Geothermal	25	10	0	0	0	0	0	0	0	0	35	0.4
Internal Combustion	54	0	0	0	0	0	0	0	0	0	54	0.6
Other	319	475	274	0	0	0	0	0	0	0	1068	12.1
Total	1324	1683	1874	310	598	947	1325	0	0	750	8811	99.8

Table 18 - Northwest Power Pool Area Summary of Significant Generation Additions (Summer Capability)

AREA	PLANT NAME / UNIT NO. / LOCATION	UNIT TYPE	NET CAPABILITY MW SUMMER	NET CAPABILITY MW WINTER	PRIMARY FUEL TYPE	PRIMARY FUEL DELIV. METHOD	IN-SERVICE DATES	S A T	C o r U	COMMENTS
IPC	Sahko 1, Twin Falls ID	HY	1	0	WAT		1-2006	U	C	
NWMT	Corette 1, Billings MT	ST	3	3	BIT	RR	1-2006	A	C	Plant rating change
NWMT	Basin Creek 1-9, Butte MT	IC	54	54	NG	PL	2-2006	TS	C	Peaking plant
NWMT	Horseshoe Bend 1-6, Great Falls	WT	2	2	WND		2-2006	TS	C	Six 1.5 MW turbines 9 MW
NWMT	Judith Gap 1-90, Judith Gap MT	WT	34	34	WND		2-2006	TS	C	Ninety 1.5 MW turbines 135 MW
AESO	Kettles Hill 1-5, Pincher Creek	WT	0	0	WND		3-2006	U	C	Benign Energy phase 1 9 MW
AESO	Long Lake 1-4, Ft. McMurray AB	GT	228	228	NG	PL	3-2006	V	C	
AESO	Syncrude UE1 11, Ft. McMurray AB	CA	27	27	NG	PL	3-2006	V	C	
NWMT	Rocky Mtn Hardin 1, Hardin MT	ST	109	109	BIT		3-2006	TS	C	
BCHA	China Creek 2, Port Alberni BC	HY	3	2	WAT		4-2006	V	C	Dev: Hupacasath First Nation
IPC	Hidden Hollow LF 1, Boise Idaho	OT	3	3	LFG		4-2006	U	C	
AESO	Soderglen 1, Fort MacLeod AB	WT	0	0	WND		5-2006	P	U	11 MW
BPA	CEP Arlington 1, OR	WT	67	67	WND		5-2006	P	U	Columbia Energy Part. 200 MW
BPA	Leaning Juniper 1, OR	WT	67	67	WND		5-2006	P	U	AKA PPM Arlington 200 MW
BPA	Big Horn Wind 1, WA	WT	67	67	WND		5-2006	P	U	Developer: PPM Energy 200 MW
IPC	Oregon Trails 1-7, Hagerman ID	WT	2	3	WND		5-2006	P	U	Seven 1.5 MW units 11 MW
IPC	Pilgrim Stage 1-7, Hagerman ID	WT	2	3	WND		5-2006	P	U	Seven 1.5 MW units 11 MW
IPC	Thousand Springs 1-7,Hagerman ID	WT	2	3	WND		5-2006	P	U	Seven 1.5 MW units 11 MW
IPC	Tuana Gulch 1-7, Hagerman ID	WT	2	3	WND		5-2006	P	U	Seven 1.5 MW units 11 MW
PACE	Currant Creek GT 1-2, Juab Cnty	GT	-280	-296	NG	PL	5-2006	RP	C	Conversion to CC operation
PACE	Currant Creek CC 1, Juab Cnty UT	CC	516	530	NG	PL	5-2006	U	C	Conversion to CC operation
SPP	Desert Peak 2, Fernley NV	GE	15	15	GEO		6-2006	V	C	
AESO	Kettles Hill 6-30, Pincher Creek	WT	0	0	WND		7-2006	P	U	Benign Energy phase 2 54 MW
AESO	Chin Chute 1-20, Chin Reservoir	WT	0	0	WND		7-2006	P	U	30 MW
BCHA	Brilliant Exp 1, Kootenay R BC	HY	120	120	WAT		8-2006	U	C	
AESO	Castle Rock 1-56, Pincher Creek	WT	0	0	WND		9-2006	P	U	115 MW
PSE	Wild Horse 127, Kittitas WA	WT	46	46	WND		9-2006	U	C	127 units @ 1.8MW each 229 MW
AESO	MEG Energy Corp. GT1,	GT	85	85	NG	PL	10-2006	P	U	
BCHA	L Bonnington 3, Kootenay R BC	HY	3	3	WAT		10-2006	A	C	Turbine upgrade/life extension
IPC	Burley Butte 1-7, Burley Idaho	WT	2	3	WND		10-2006	P	U	Seven 1.5 MW units 11 MW
IPC	Lava Beds 1-12, Hagerman ID	WT	3	5	WND		10-2006	P	U	Twelve 1.5 MW units 18 MW
AESO	Syncrude Aurora G21, Ft. McMurray	GT	86	86	NG	PL	12-2006	P	U	
BCHA	Waneta 4, Pend Oreille R BC	HY	25	25	WAT		12-2006	A	C	Turbine upgrade/life extension
BPA	Seven Mile Hill 1, OR	WT	17	17	WND		12-2006	P	U	50 MW
IPC	Notch Butte 1-12, Twin Falls ID	WT	3	5	WND		12-2006	P	U	Twelve 1.5 MW units 18 MW
SPP	Burdette 2, Steamboat NV	GE	10	10	GEO		12-2006	U	C	aka Galena 2
IPC	Emmett Facility 1, Emmett ID	OT	7	7	WDS	TK	1-2007	U	C	Wood-fired steam turbine
IPC	Golden Valley 1-7, Burley Idaho	WT	2	3	WND		1-2007	P	U	Seven 1.5 MW units 11 MW
IPC	Salmon Falls 1-14, Hagerman ID	WT	4	6	WND		1-2007	P	U	Fourteen 1.5 MW units 21 MW
PGE	Port Westward CC 1, Clatskanie OR	CC	356	426	NG	PL	3-2007	U	C	
AESO	Purple Springs 1-60, Taber AB	WT	0	0	WND		4-2007	P	U	Shell/Enmax 80 MW
AESO	Horizon Upgrading GT1,Ft. MacKay	GT	86	86	NG	PL	4-2007	P	U	Canadian Natural Resources Ltd
AESO	Horizon Upgrading GT2,Ft. MacKay	GT	86	86	NG	PL	4-2007	P	U	Canadian Natural Resources Ltd
AESO	Horizon Upgrading ST1,Ft. MacKay	ST	15	15	NG	PL	4-2007	P	U	Canadian Natural Resources Ltd
IPC	Lowline Midway 1, Twin Falls ID	HY	2	0	WAT		4-2007	U	C	
AESO	Blue Trail 1-40, Macleod Flats	WT	0	0	WND		5-2007	P	U	Vision Quest, 60 MW
AVA	Cabinet Gorge 4, Clark Fork R ID	HY	11	11	WAT		5-2007	A	C	Upgrade of existing unit
AESO	Suncor Firebag, Ft. McMurray	GT	94	94	NG	PL	6-2007	P	U	
BCHA	S Slocan 1, Kootenay River BC	HY	3	3	WAT		6-2007	A	C	Turbine upgrade/life extension
IPC	Raft River I 1, Malta ID	GE	10	10	GEO		6-2007	U	C	
PACE	Summit-Lake Side CC 1, Vineyard	CC	543	550	NG	PL	6-2007	T	U	Devel: Summit Vineyard LLC
SPP	TS Power GT 1-4, Eureka Cnty NV	GT	0	0	DFO	TK	8-2007	L	U	Backup units 1-4 at 35 MW each
PSE	Ormat 1, Blaine WA	OT	5	5	OTH		11-2007	P	U	Waste heat recovery unit
IPC	Milner Dam 1-12, Twin Falls ID	WT	3	5	WND		11-2007	P	U	Twelve 1.5 MW units 18 MW
AESO	Waterton 1-4,	WT	0	0	WND		12-2007	P	U	Visionquest 300 MW
BCHA	Corra Linn 1, Kootenay River BC	HY	2	2	WAT		12-2007	A	U	Turbine upgrade/life extension
BPA	Orion Wind 1, OR	WT	100	100	WND		12-2007	P	U	300 MW
BPA	Combine Hills II 1, OR	WT	35	35	WND		12-2007	T	U	Dev: Eurus 104 MW
BPA	Willow Creek 1, WA	WT	60	60	WND		12-2007	P	U	180 MW
BPA	Columbia Hills 1, WA	WT	42	42	WND		12-2007	P	U	125 MW
BPA	Klondike Phase 3 1, OR	WT	100	100	WND		12-2007	P	U	300 MW
BPA	Windtricity 1, WA	WT	50	50	WND		12-2007	T	U	150 MW
BPA	White Creek 1, WA	WT	67	67	WND		12-2007	P	U	200 MW
AESO	Summerview 2, Pincher Creek AB	WT	0	0	WND		1-2008	P	U	Vision Quest, phase 2 60 MW
NWMT	Bull Mountain 1-2, Broadview MT	ST	700	700	LIG	CV	3-2008	P	U	
BCHA	Aberfeldie 1-2, Bull River BC	HY	18	0	WAT		4-2008	P	U	New powerhouse and penstock
PACE	Two Elk 1, Campbell Cnty WY	OT	274	282	WC	TK	4-2008	P	U	Owner: North Amer. Power Group
BCHA	S Slocan 3, Kootenay River BC	HY	3	3	WAT		5-2008	A	U	Turbine upgrade/life extension
AVA	Noxon Rapids 4, Clark Fork R MT	HY	12	12	WAT		5-2008	A	C	Upgrade of existing unit
IPC	Danskin GT 3, Mt. Home ID	GT	165	178	NG	PL	6-2008	P	U	
SPP	TS Power 1, Eureka Cnty NV	ST	200	200	SUB	RR	6-2008	L	U	Owner: Newmont Mining 200 MW
SPP	Tracy CC 1, Sparks NV	CC	514	514	NG	PL	6-2008	L	U	
PACW	Condit 1-2, Klickitat County WA	HY	-14	-14	WAT		10-2008	RT	C	
BCHA	Corra Linn 2, Kootenay River BC	HY	2	2	WAT		12-2008	A	U	Turbine upgrade/life extension
NWMT	Southern MT Elec. 1,Great Falls	ST	268	268	LIG	RR	3-2009	P	U	
BCHA	Gordon M Shrum 6, Peace River BC	HY	30	30	WAT		4-2009	P	U	Capacity enhancement
AVA	Noxon Rapids 1, Clark Fork R MT	HY	12	12	WAT		5-2009	A	U	Upgrade of existing unit
BCHA	Gordon M Shrum 7, Peace River BC	HY	30	30	WAT		4-2010	P	U	Capacity enhancement
BCHA	Gordon M Shrum 8, Peace River BC	HY	30	30	WAT		4-2010	P	U	Capacity enhancement
PACW	Powerdale 1, Hood River Cnty OR	HY	-6	-6	WAT		4-2010	RT	U	
AVA	Noxon Rapids 2, Clark Fork R MT	HY	12	12	WAT		5-2010	A	U	Upgrade of existing unit
BCHA	Revelstoke 5, Columbia River BC	HY	500	500	WAT		10-2010	P	U	
IPC	Shoshone Falls 1-2, Snake River	HY	-1	-1	WAT		11-2010	RT	U	
IPC	Shoshone Falls 4, Snake River ID	HY	33	53	WAT		11-2010	P	U	64 MW
BCHA	Waneta Expansion 1,Pend Oreille	HY	435	435	WAT		1-2011	P	U	New power plant at Waneta dam
AVA	Noxon Rapids 3, Clark Fork R MT	HY	12	12	WAT		5-2011	A	U	Upgrade of existing unit
NWMT	Nelson Creek 1-2, Colstrip MT	ST	500	500	LIG	CV	10-2011	P	U	Formerly called MT Lignite
PACE	Hunter 4, Emery Cnty UT	ST	575	575	BIT	TK	1-2012	P	U	Devel: PacifiCorp
SPP	*Ely EC 1, White Pine NV	ST	750	750	BIT	RR	1-2012	P	U	
SPP	*Ely EC 2, White Pine NV	ST	750	750	BIT	RR	1-2015	P	U	

* Not included in 2006 Power Supply Assessment report
See the appendix for a description of the unit type codes, status codes, and the committed/uncommitted codes.

Rocky Mountain Power Area (RMPA)



Aquila Networks – WPC	WPE
Arkansas River Power Authority	ARPA
Basin Electric Power Cooperative	BEPC
Black Hills Power	BHP
Colorado Springs Utilities	CSU
Municipal Energy Agency of Nebraska	MEAN
Platte River Power Authority	PRPA
Public Service Company of Colorado	PSC
Tri-State Generation & Transmission Association, Inc.	TSGT
U.S.B.R. Great Plains Region	USGP
U.S.B.R. Upper Colorado Region	USUC
Western Area Power Administration - Golden Colorado Area	WAHQ
Loveland Area	WACM

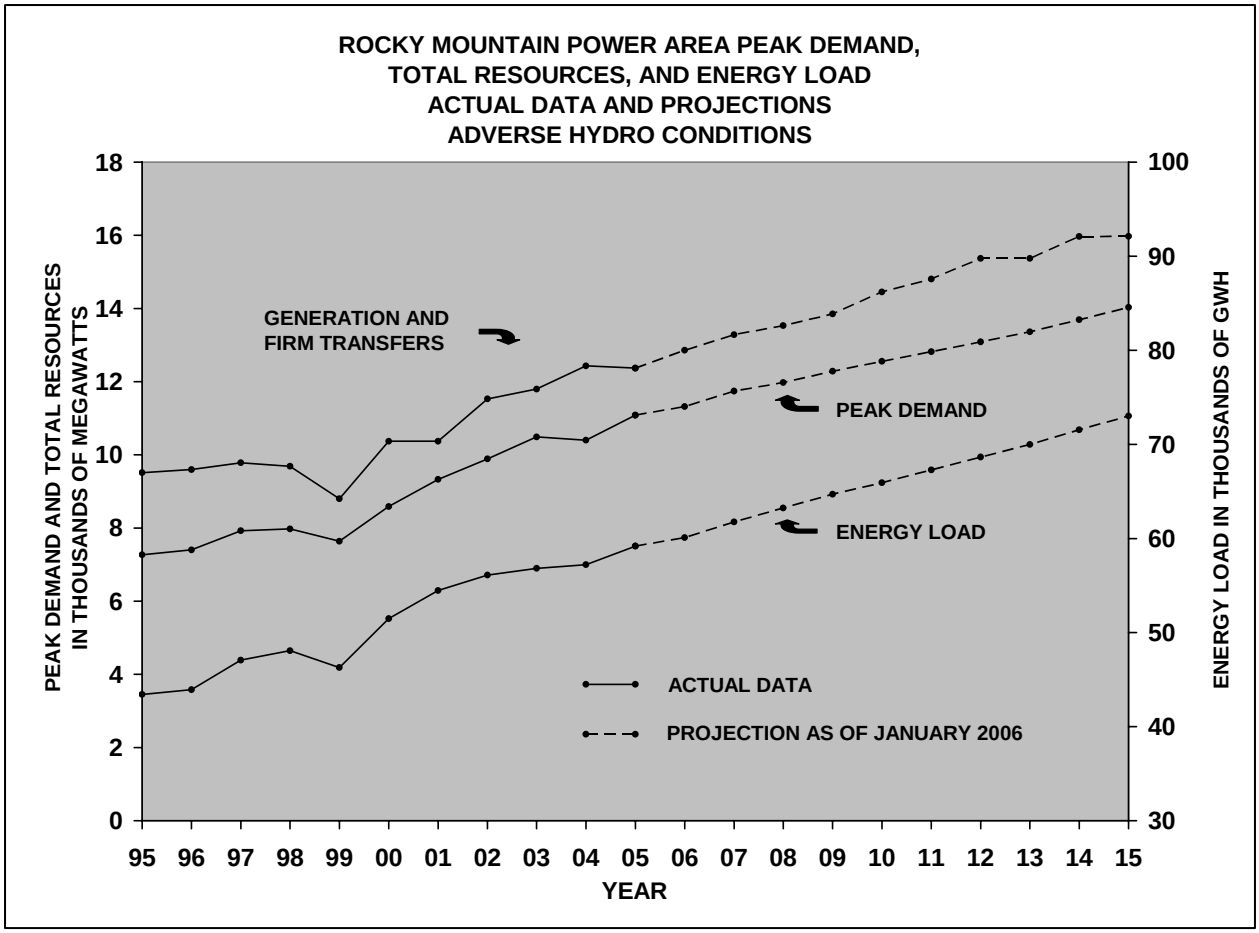


Figure 8

Table 19 - Rocky Mountain Power Area Actual Loads and Resources for 2005

PEAK DEMAND – MW		JAN	FEB	MAR	APR	MAY	JUN
Loads -	Firm	8524	7952	7649	6927	8631	9297
	Interruptible & Load Mgt	370	382	384	344	258	257
	Total	8894	8334	8033	7271	8889	9554
	Forecast Deviation - %	0.4	-3.8	-2.3	-7.1	5.2	-3.8
Generation -	Hydro	1266	1266	1266	1303	1303	1303
	Thermal	11652	11652	11652	11472	11259	11259
	Other	22	22	22	22	22	22
	Total	12940	12940	12940	12797	12584	12584
Total Unavailable Generation *		363	169	240	1337	1812	460
Net Firm Transfers - MRO **		-119	-117	-112	-159	-95	-14
	NWPP	287	426	401	404	280	188
	AZ-NM-SNV **	151	118	-43	-24	93	-98
	Total Net Firm Transfers	319	427	246	221	278	76
Net Generation & Firm Transfers		12258	12344	12454	11239	10494	12048
Margin Over Firm Loads - MW		3734	4392	4805	4312	1863	2751
Margin Over Firm Loads - Percent		43.8	55.2	62.8	62.2	21.6	29.6
ENERGY - GWH							
Total Load		5082	4469	4812	4435	4696	4900
	Forecast Deviation - %	-6.6	-11.5	-2.5	-8.6	-1.0	-3.8

PEAK DEMAND – MW		JUL	AUG	SEP	OCT	NOV	DEC	
Loads -	Firm	11036	10109	8917	7548	8423	9452	
	Interruptible & Load Mgt	50	219	175	181	221	76	
	Total	11086	10328	9092	7729	8644	9528	
	Forecast Deviation - %	2.1	-2.5	-4.3	-4.8	-3.1	2.5	
Generation -	Hydro	1303	1303	1303	1266	1266	1266	
	Thermal	11251	11251	11259	11652	11652	11652	
	Other	22	22	22	22	22	22	
	Total	12576	12576	12584	12940	12940	12940	
Total Unavailable Generation *		261	450	727	1280	973	238	
Net Firm Transfers - MRO **		-18	-21	-20	-119	-175	-127	
	NWPP	279	169	376	386	437	421	
	AZ-NM-SNV **	-53	-121	-70	-6	77	17	
	Total Net Firm Transfers	208	27	286	261	339	311	
Net Generation & Firm Transfers		12107	12099	11571	11399	11628	12391	
Margin Over Firm Loads - MW		1071	1990	2654	3851	3205	2939	
Margin Over Firm Loads - Percent		9.7	19.7	29.8	51.0	38.1	31.1	
ENERGY - GWH								TOTAL
Total Load		5886	5410	4760	4593	4770	5377	59190
	Forecast Deviation - %	5.5	-8.2	-9.8	-5.1	-1.4	1.1	3.1

* Includes Maintenance, Forced Outages, and Inoperable Capability.
** Minus (-) indicates transfer into WECC Region.

Table 20 - Rocky Mountain Power Area Estimated Peaks Demands, Resources, and Reserves 2006 - 2015

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Month	JUL	JUL	JUL	JUL	JUL	JUL	JUL	JUL	JUL	JUL
Loads – Firms	11107	11506	11720	12003	12248	12513	12783	13056	13386	13721
Int. & Load Mgt	216	238	260	285	308	308	308	308	308	308
Total - MW	11323	11744	11980	12288	12556	12821	13091	13364	13694	14029
Growth from Previous Yr. - %	2.1	3.7	2.0	2.6	2.2	2.1	2.1	2.1	2.5	2.4
Generation ± Transfers - MW	12857	13286	13531	13851	14454	14804	15370	15370	15971	15972
Maint./Inoperable Cap. - MW	0	0	0	0	0	0	0	0	0	0
Reserve Capability MW	1750	1780	1811	1848	2206	2291	2587	2314	2585	2251
Percent of Firm Peak Demand	15.8	15.5	15.5	15.4	18.0	18.3	20.2	17.7	19.3	16.4

Projected Average Annual Summer Compound Growth Rate (2005-2015) - 2.4%

			WINTER PEAK					Adverse Hydro Conditions		
	06-07	07-08	08-09	09-10	10-11	11-12	12-13	13-14	14-15	15-16
Month	DEC	DEC	DEC	DEC	DEC	DEC	DEC	DEC	DEC	DEC
Loads – Firms	9545	9840	10014	10228	10432	10646	10863	11087	11349	11604
Int. & Load Mgt	135	136	138	141	145	145	145	145	145	145
Total - MW	9680	9976	10152	10369	10577	10791	11008	11232	11494	11749
Growth from Previous Yr. - %	1.6	3.1	1.8	2.1	2	2	2	2	2.3	2.2
Generation ± Transfers - MW	13078	13610	13897	14395	15144	15500	16065	16665	16666	16667
Maint./Inoperable Cap. - MW	82	82	82	82	82	82	82	82	82	82
Reserve Capability MW	3451	3688	3801	4085	4630	4772	5120	5496	5235	4981
Percent of Firm Peak Demand	36.2	37.5	38.0	39.9	44.4	44.8	47.1	49.6	46.1	42.9

Projected Average Annual Winter Compound Growth Rate (2005/06-2015/2016) - 2.1%

Table 21 - Rocky Mountain Power Area Summary of Generation Additions (Summer Capability - MW)

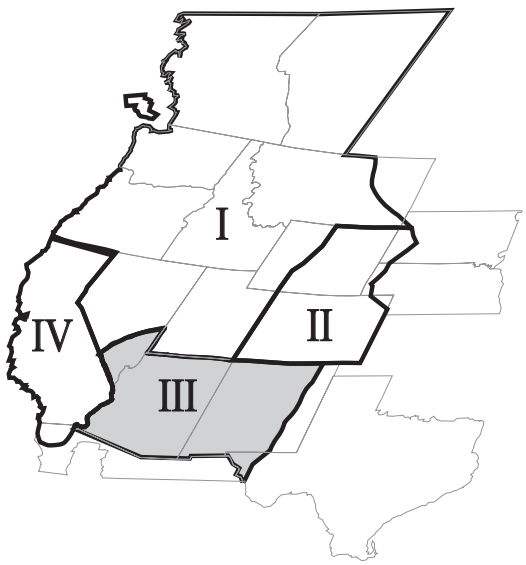
Generation Type	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	10 Yr. Period	% of Total
Hydro - Conventional	0	0	0	0	0	0	0	0	0	0	0	0.0
Hydro - Pumped Storage	0	0	0	0	0	0	0	0	0	0	0	0.0
Steam - Coal	0	80	0	0	750	385	600	600	0	0	2415	65.6
Steam - Oil	0	0	0	0	0	0	0	0	0	0	0	0.0
Steam - Gas	0	0	0	0	0	0	0	0	0	0	0	0.0
Nuclear	0	0	0	0	0	0	0	0	0	0	0	0.0
Combustion Turbine	0	534	0	0	0	0	0	0	0	0	534	14.5
Combined Cycle	0	0	163	483	0	0	0	0	0	0	646	17.6
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0.0
Internal Combustion	0	0	0	0	0	0	0	0	0	0	0	0.0
Other	6	0	78	0	0	0	0	0	0	0	84	2.3
Total	6	614	241	483	750	385	600	600	0	0	3679	100.0

Table 22 - Rocky Mountain Power Area Summary of Significant Generation Additions (Summer Capability)

AREA	PLANT NAME / UNIT NO. / LOCATION	UNIT TYPE	NET CAPABILITY MW SUMMER	NET CAPABILITY MW WINTER	PRIMARY FUEL FUEL TYPE	PRIMARY FUEL DELIV. METHOD	IN-SERVICE DATES	STAT	Cor U	COMMENTS
PSC	Spring Canyon 1-40,Logan Cnty CO	WT	6	6	WND		2-2006	V	C	PSC all-source RFP selection
PSC	Gross 1, Jefferson Cnty CO	HY	0	0	WAT		6-2006	V	C	Owner: Denver Water Board
PSC	Blue Spruce 3-4, Aurora CO	GT	264	308	NG	PL	5-2007	P	U	PSC all-source RFP selection
PSC	Spindle Hill 1-2, Weld Cnty CO	GT	270	314	NG	PL	5-2007	P	U	PSC all-source RFP selection
WACM	WYGEN 2, Wyodak WY	ST	80	80	BIT	CV	7-2007	U	C	Owner: Black Hills Generation
PSC	Peetz Expansion 2, near Peetz CO	WT	40	40	WND		1-2008	P	U	PSC all-source RFP selection
PSC	Cedar Creek 2, Weld Cnty CO	WT	30	30	WND		1-2008	P	U	PSC all-source RFP selection
PSC	Colorado Green II 2, near Lamar	WT	8	8	WND		1-2008	P	U	PSC all-source RFP selection
PSC	Rocky Mountain CC2A, Hudson CO	CS	163	239	NG	PL	5-2008	P	U	PSC all-source RFP selection
PSC	Squirrel 2, Fountain CO	CC	483	531	NG	PL	5-2009	P	U	PSC all-source RFP selection
PSC	Comanche 3, Pueblo CO	ST	750	780	BIT	RR	1-2010	L	U	PSC all-source RFP selection
WACM	*Dry Fork 1, Gillette WY	ST	385	385	BIT	RR	1-2011	P	U	Owner: Basin Electric
WACM	Holcomb 1, Holcomb KS	ST	600	600	BIT	CV	7-2012	P	U	
WACM	Holcomb 2, Holcomb KS	ST	600	600	BIT	CV	12-2013	P	U	

* Not included in 2006 Power Supply Assessment report
See the appendix for a description of the unit type codes, status codes, and the committed/uncommitted codes.

Arizona-New Mexico-Southern Nevada Power Area (AZ-NM-SNV)



Arizona Electric Power Cooperative, Inc.	AEPC
Arizona Power Authority	APA
Arizona Public Service Company	APS
Central Arizona Water Conservation District	CAWC
Duke – Arlington	DEAA
El Paso Electric Company	EPE
Farmington Electric Utility System	FARM
Gila Bend Power Partners, LLC	GBPP
Gila River Maricopa Arizona	GRMA
Harquahala Generating Company, LLC	HGC
Harquahala Generator Maricopa Arizona	HGMA
Imperial Irrigation District	IID
Los Alamos County	LAC
Morenci Water & Electric Company	MWEC
Navajo Tribal Utility Authority	NTUA
Nevada Power Company	NEVP
Public Service Company of New Mexico	PNM
Salt River Project	SRP
Southwest Transmission Cooperative, Inc.	SWTC
Texas-New Mexico Power Company	TNP
Tri-State Generation & Transmission Association, Inc.	TSGT
Tucson Electric Power Company	TEP
U.S.B.R. Lower Colorado Region	USLC
Valley Electric Association, Inc.	VEA
Western Area Power Administration - Phoenix Area	WALC

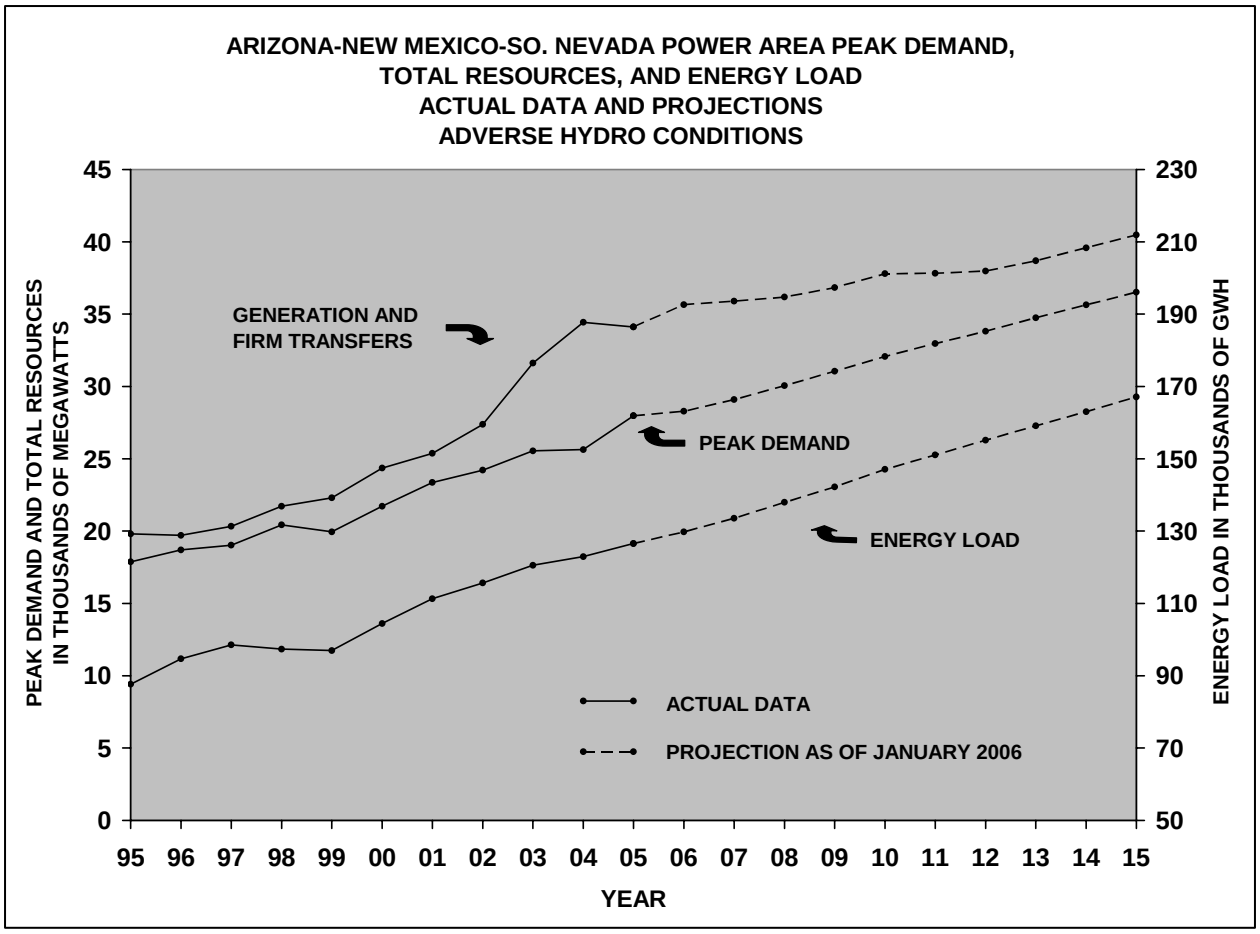


Figure 9

Table 23 - Arizona-New Mexico-Southern Nevada Power Area Actual Loads and Resources for 2005

PEAK DEMAND – MW		JAN	FEB	MAR	APR	MAY	JUN
Loads -	Firm	16140	14816	14451	15313	23266	25562
	Interruptible & Load Mgt	302	293	300	352	289	268
	Total	16442	15109	14751	15665	23555	25830
	Forecast Deviation - %	-5.3	-10.2	-10.2	-14.5	2.9	2.2
Generation -	Hydro	3943	3923	3933	3998	4040	4026
	Thermal	33040	33040	33040	32617	32708	32644
	Other	569	569	569	569	573	573
	Total	37552	37532	37542	37184	37321	37243
Total Unavailable Generation *		2183	2323	1430	2800	2361	1220
Net Firm Transfers - NWPP		1294	1219	738	325	-120	-171
	SPP **	-622	-622	-439	-472	-472	-472
	RMPA	-67	-171	2	-173	-202	-277
	CA-MX	3479	3580	3737	3173	3480	3205
	Total Net Firm Transfers	4084	4006	4038	2853	2686	2285
Net Generation & Firm Transfers		31285	31203	32074	31531	32274	33738
Margin Over Firm Loads - MW		15145	16387	17623	16218	9008	8176
Margin Over Firm Loads - Percent		93.8	110.6	122.0	105.9	38.7	32.0
ENERGY - GWH							
Total Load		9259	8046	8581	8745	10919	12282
	Forecast Deviation - %	-2.8	-4.4	-3.1	-1.1	4.8	2.4

PEAK DEMAND – MW		JUL	AUG	SEP	OCT	NOV	DEC	
Loads -	Firm	27699	25941	24415	20448	15753	16854	
	Interruptible & Load Mgt	275	250	272	304	257	276	
	Total	27974	26191	24687	20752	16010	17130	
	Forecast Deviation - %	3.7	-1.7	-0.7	2.0	-1.5	-2.7	
Generation -	Hydro	4032	4026	3999	3961	3931	3943	
	Thermal	32644	32644	32644	33188	33633	33633	
	Other	573	573	569	569	569	570	
	Total	37249	37243	37212	37718	38133	38146	
Total Unavailable Generation *		333	1637	629	1791	1564	1886	
Net Firm Transfers - NWPP		171	55	-20	928	1172	1193	
	SPP **	-472	-472	-472	-339	-472	-472	
	RMPA	-53	-128	-108	-113	-192	-72	
	CA-MX	3485	2961	3683	3416	3555	3365	
	Total Net Firm Transfers	3131	2416	3083	3892	4063	4014	
Net Generation & Firm Transfers		33785	33190	33500	32035	32506	32246	
Margin Over Firm Loads - MW		6086	7249	9085	11587	16753	15392	
Margin Over Firm Loads - Percent		22.0	27.9	37.2	56.7	106.3	91.3	
ENERGY - GWH								TOTAL
Total Load		14658	13568	11826	9963	8880	9813	126540
	Forecast Deviation - %	8.2	0.6	-0.7	-0.4	1.4	3.2	1.0

* Includes Maintenance, Forced Outages, and Inoperable Capability.
** Minus (-) indicates transfer into WECC Region.

Table 24 - Arizona-New Mexico-So. Nevada Power Area Estimated Peaks Demands, Resources, and Reserves 2006 - 2015

	SUMMER PEAK							Adverse Hydro Conditions		
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Month	JUL	JUL	JUL	JUL	JUL	JUL	JUL	JUL	JUL	JUL
Loads – Firms	27946	28753	29722	30706	31733	32622	33465	34411	35302	36181
Int. & Load Mgt	335	336	337	339	339	341	342	343	344	345
Total - MW	28281	29089	30059	31045	32072	32963	33807	34754	35646	36526
Growth from Previous Yr. - %	1.1	2.9	3.3	3.3	3.3	2.8	2.6	2.8	2.6	2.5
Generation ± Transfers - MW	35658	35904	36186	36833	37804	37830	37987	38686	39586	40477
Maint./Inoperable Cap. - MW	31	31	31	31	31	31	31	31	31	31
Reserve Capability MW	7681	7120	6433	6096	6040	5177	4491	4244	4253	4265
Percent of Firm Peak Demand	27.5	24.8	21.6	19.9	19.0	15.9	13.4	12.3	12.0	11.8

Projected Average Annual Summer Compound Growth Rate (2005-2015) – 2.7%

	WINTER PEAK							Adverse Hydro Conditions		
	06-07	07-08	08-09	09-10	10-11	11-12	12-13	13-14	14-15	15-16
Month	JAN	JAN	JAN	JAN	JAN	JAN	JAN	JAN	JAN	JAN
Loads – Firms	17853	18374	18940	19557	20066	20577	21078	21608	22149	22642
Int. & Load Mgt	336	337	339	339	341	342	343	344	345	346
Total - MW	18189	18711	19279	19896	20407	20919	21421	21952	22494	22988
Growth from Previous Yr. - %	0.8	2.9	3.0	3.2	2.6	2.5	2.4	2.5	2.5	2.2
Generation ± Transfers - MW	35827	35953	36705	37749	37821	37846	37952	37895	38113	38113
Maint./Inoperable Cap. - MW	1491	2000	1937	1877	1423	1507	1899	1737	1887	1520
Reserve Capability MW	16483	15579	15828	16315	16332	15762	14975	14550	14077	13951
Percent of Firm Peak Demand	92.3	84.8	83.6	83.4	81.4	76.6	71.0	67.3	63.6	61.6

Projected Average Annual Winter Compound Growth Rate (2005/06-2015/2016) - 3.0%

Table 25 - Arizona-New Mexico-So. Nevada Power Area Summary of Generation Additions (Summer Capability - MW)

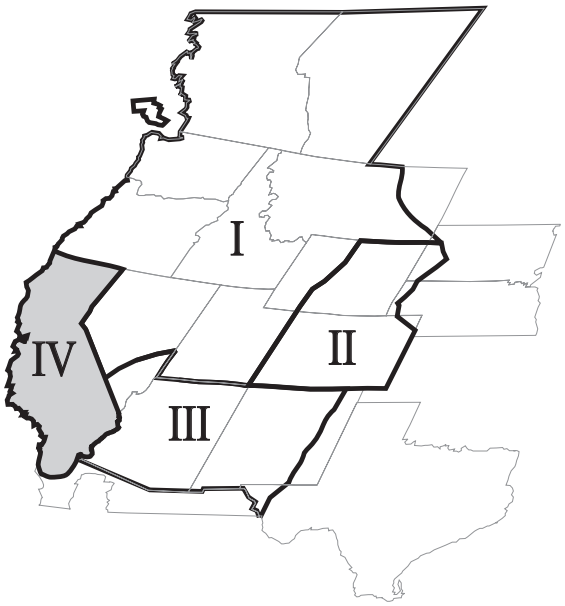
Generation Type	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	10 Yr. Period	% of Total
Hydro - Conventional	0	0	0	0	0	0	0	0	0	0	0	0.0
Hydro - Pumped Storage	0	0	0	0	0	0	0	0	0	0	0	0.0
Steam - Coal	435	0	0	0	400	0	0	0	0	0	835	16.5
Steam - Oil	0	0	0	-48	0	0	-80	0	0	0	-128	-2.5
Steam - Gas	0	0	0	0	0	0	0	-48	-126	0	-174	-3.4
Nuclear	71	0	71	0	0	0	0	0	0	0	142	2.8
Combustion Turbine	98	-159	80	70	70	-140	0	70	-70	0	19	0.4
Combined Cycle	2005	235	500	621	0	288	234	0	288	0	4171	82.2
Geothermal	0	0	170	0	0	25	0	0	0	0	195	3.8
Internal Combustion	0	0	0	0	0	0	0	0	0	0	0	0.0
Other	1	1	1	2	1	2	2	0	0	0	10	0.2
Total	2610	77	822	645	471	175	156	22	92	0	5070	100.0

Table 26 - Arizona-New Mexico-So. Nevada Power Area Summary of Significant Generation Additions
(Summer Capability)

AREA	PLANT NAME / UNIT NO. / LOCATION	UNIT TYPE	NET CAPABILITY MW SUMMER	NET CAPABILITY MW WINTER	PRIMARY FUEL FUEL TYPE	PRIMARY FUEL DELIV. METHOD	IN-SERVICE DATES	ST AT	Cor U	COMMENTS
APS	Palo Verde 1, Wintersburg AZ	NP	71	71	NUC		1-2006	A	C	Uprate - new LP turbines
APS	Cholla 2, Joseph City AZ	ST	15	15	SUB	RR,TK	1-2006	A	C	
APS	Four Corners 4-5, Fruitland NM	ST	20	20	SUB	RR,TK	1-2006	A	C	
TEP	SGS Solar PV1D, Apache Cnty AZ	PV	1	1	SUN		1-2006	A	C	
NEVP	Chuck Lenzie CC 1, Clark County	CC	580	580	NG	PL	2-2006	V	C	
NEVP	Chuck Lenzie CC 2, Clark County	CC	580	580	NG	PL	4-2006	V	C	
PNM	Abiquiu 3, Abiquiu NM	HY	0	0	WAT		4-2006	P	U	Owner: LAC 3 MW
PNM	Luna CC 1, Deming NM	CC	570	570	NG	PL	5-2006	V	C	
SRP	Santan CC 2, Gilbert AZ	CC	275	275	NG	PL	5-2006	V	C	
NEVP	Allen GT2, Clark County NV	GT	77	77	NG	PL	6-2006	V	C	Dev: Sierra Pacific Resources
PNM	LANL TA-3 4, Los Alamos NM	GT	21	21	NG	PL	6-2006	V	C	
TEP	Springerville 3, Apache Cnty AZ	ST	400	400	SUB	RR	7-2006	V	C	Developer: TSGT/TEP
TEP	SGS Solar PV1E, Apache Cnty AZ	PV	1	1	SUN		1-2007	P	U	
PNM	Afton 1, Afton NM	GT	-141	-141	NG	PL	5-2007	RP	U	converting to CC operation
PNM	Afton CT 1, Afton NM	CT	141	141	NG	PL	5-2007	T	U	converting from SC operation
PNM	Afton CA 1, Afton NM	CA	94	94	NG	PL	5-2007	T	U	
PNM	Valencia 1, Las Vegas NM	GT	-18	-18	DFO	TK	9-2007	RT	U	Owner: PNM
APS	Palo Verde 3, Wintersburg AZ	NP	71	71	NUC		1-2008	A	U	Uprate
TEP	SGS Solar PV1F, Apache Cnty AZ	PV	1	1	SUN		1-2008	P	U	
IID	Salton Sea 6 #1, Calipatria CA	GE	170	170	GEO		5-2008	T	U	Owner: CalEnergy-Obsidian
IID	Niland 1-2, Niland CA	GT	80	80	NG	PL	5-2008	P	U	Formerly Unidentified GT 1-2
TEP	Bowie CC 1, Cochise Cnty AZ	CC	500	500	NG	PL	12-2008	T	U	Developer: SWPG
TEP	SGS Solar PV1G, Apache Cnty AZ	PV	2	2	SUN		1-2009	P	U	
IID	El Centro 3, El Centro CA	ST	-48	-48	RFO	TK,RR	5-2009	RP	U	Repowered to CC
IID	El Centro 3, El Centro CA	CA	34	34	NG	PL	5-2009	RP	U	Repowered to CC, steam portion
IID	El Centro 3A, El Centro CA	CT	87	87	NG	PL	5-2009	RP	U	Repowered to CC, comb. turbine
EPE	Newman GT 1, El Paso TX	GT	70	70	NG	PL	6-2009	P	U	Potential CT part of CC plant
TEP	Bowie CC 2, Cochise Cnty AZ	CC	500	500	NG	PL	12-2009	T	U	Developer: SWPG
SRP	Springerville 4, Apache Cnty AZ	ST	400	400	SUB	RR	1-2010	P	U	
TEP	SGS Solar PV1H, Apache Cnty AZ	PV	1	1	SUN		1-2010	P	U	
EPE	Newman GT 2, El Paso TX	GT	70	70	NG	PL	6-2010	P	U	Potential CT part of CC plant
TEP	SGS Solar PV1I, Apache Cnty AZ	PV	2	2	SUN		1-2011	P	U	
EPE	Newman GT 1, El Paso TX	GT	-70	-70	NG	PL	2-2011	RP	U	Potential repower to CC plant
EPE	Newman GT 2, El Paso TX	GT	-70	-70	NG	PL	2-2011	RP	U	Potential repower to CC plant
EPE	Newman CC 5, El Paso TX	CC	288	288	NG	PL	2-2011	RP	U	Potential repower to CC plant
IID	Salton Sea 6 #1, Calipatria CA	GE	25	25	GEO		5-2011	A	U	Owner: CalEnergy-Obsidian
TEP	SGS Solar PV1J, Apache Cnty AZ	PV	2	2	SUN		1-2012	P	U	
IID	El Centro 4, El Centro CA	ST	-80	-80	RFO	TK,RR	5-2012	RP	U	Repowered to CC
IID	El Centro 4, El Centro CA	CA	80	80	NG	PL	5-2012	RP	U	Repowered to CC, steam portion
IID	El Centro 4A, El Centro CA	CT	154	154	NG	PL	5-2012	RP	U	Repowered to CC, comb. turbine
EPE	Rio Grande 6, Near El Paso TX	ST	-48	-48	NG	PL	1-2013	RP	U	Potential repower
EPE	Newman GT 3, El Paso TX	GT	70	70	NG	PL	6-2013	P	U	Potential CT part of CC plant
EPE	Rio Grande 7, Near El Paso TX	ST	-45	-45	NG	PL	1-2014	RP	U	Potential repower
EPE	Newman 2, El Paso TX	ST	-81	-82	NG	PL	1-2014	RP	U	Potential repower
EPE	Newman GT 3, El Paso TX	GT	-70	-70	NG	PL	2-2014	RP	U	Potential repower to CC plant
EPE	Newman CC6A, El Paso TX	CT	70	70	NG	PL	2-2014	RP	U	Potential repower to CC plant
EPE	Newman CC6B, El Paso TX	CT	70	70	NG	PL	2-2014	P	U	Potential CT part of CC plant
EPE	Newman CC6C, El Paso TX	CA	148	148	NG	PL	2-2014	P	U	Potential repower to CC plant

See the appendix for a description of the unit type codes, status codes, and the committed/uncommitted codes.

California-Mexico Power Area (CA-MX)



U.S. Systems

Anaheim, City of	ANHM
Burbank Water and Power Department	BURB
California Department of Water Resources	CDWR
California Independent System Operator	CISO
Glendale, City of - Public Service Department	GLEN
Hetch Hetchy Water & Power	HHWP
Los Angeles Department of Water and Power	LDWP
Metropolitan Water District/Southern California	MWD
Modesto Irrigation District	MID
Northern California Power Agency	NCPA
Oak Creek Energy Systems, Inc.	OCES
Pacific Gas and Electric Company	PG&E
Pasadena, City of	PASA
Redding, City of	RDNG
Riverside, City of	RVSD
Roseville Electric	RVE
Sacramento Municipal Utility District	SMUD
San Diego Gas & Electric Company	SDGE
Santa Clara, City of	SNCL
Southern California Edison Company	SCE
Transmission Agency of Northern California	TANC
Turlock Irrigation District	TIDC
U.S.B.R. Mid-Pacific Region	USMP
Vernon, City of	VERN
Western Area Power Administration - Sacramento, California	WASN

Mexican System – Baja California

Comisión Federal de Electricidad	CFE

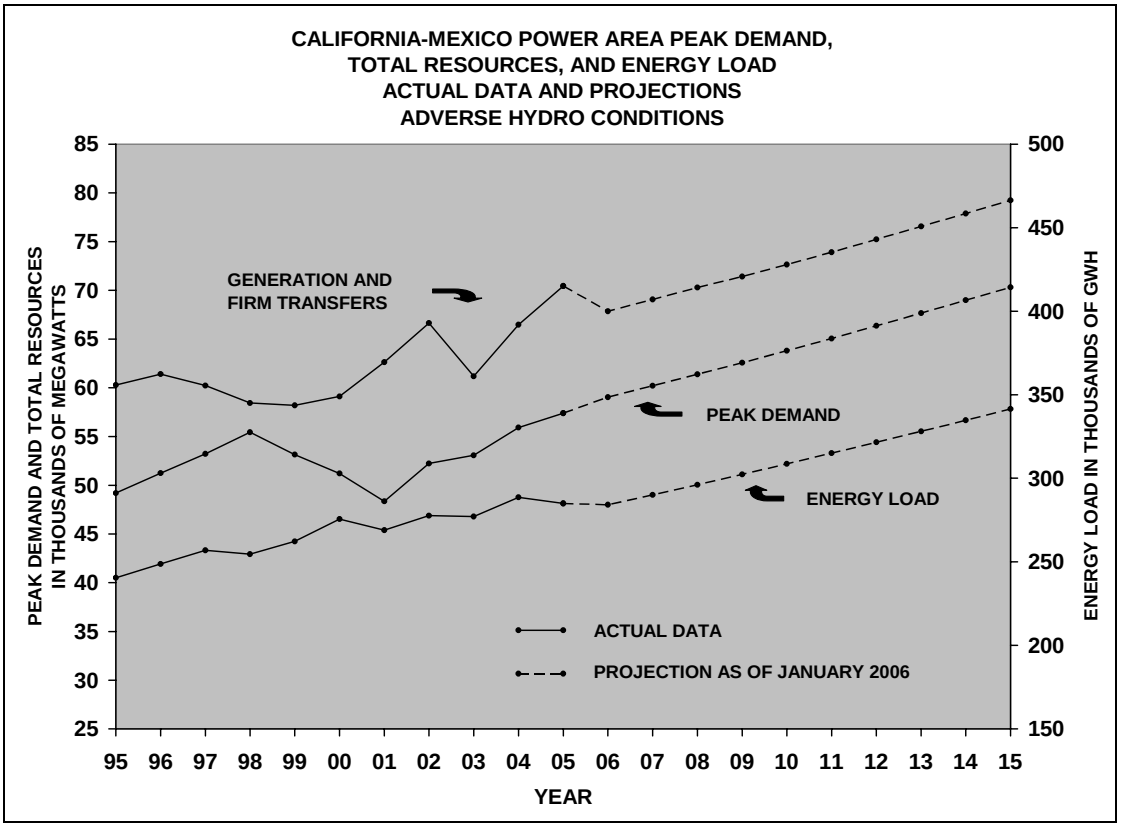


Figure 10

Table 27 - California-Mexico Power Area Actual Loads and Resources for 2005

PEAK DEMAND – MW		JAN	FEB	MAR	APR	MAY	JUN
Loads -	Firm	38758	37018	36186	36294	44326	47056
	Interruptible & Load Mgt	1310	1310	1310	1310	1310	1780
	Total	40068	38328	37496	37604	45636	48836
	Forecast Deviation - %	0.4	-3.0	-5.3	-9.8	-3.4	-7.7
Generation -	Hydro	10757	10757	10757	10777	10777	12276
	Thermal	37302	37217	37370	37546	38328	43036
	Other	4256	4256	4268	4268	4301	4022
	Total	52315	52230	52395	52591	53406	59334
Total Unavailable Generation *		9348	10786	10941	12216	10772	6220
Net Firm Transfers - NWPP **		-810	-1855	-2029	-2059	-2321	-3783
	AZ-NM-SNV **	-4296	-5266	-5039	-5155	-5411	-6336
	Total Net Firm Transfers	-5106	-7121	-7068	-7214	-7732	-10119
Net Generation & Firm Transfers		48073	48565	48522	47589	50366	63233
Margin Over Firm Loads - MW		9315	11547	12336	11295	6040	16177
Margin Over Firm Loads - Percent		24.0	31.2	34.1	31.1	13.6	34.4
ENERGY - GWH							
Total Load		22618	19969	21782	21424	23331	23985
	Forecast Deviation - %	-4.7	-6.4	-7.8	-6.7	-6.0	-4.4

PEAK DEMAND – MW		JUL	AUG	SEP	OCT	NOV	DEC	
Loads -	Firm	55579	53205	48348	42402	39175	40600	
	Interruptible & Load Mgt	1810	1810	1780	1310	1310	1310	
	Total	57389	55015	50128	43712	40485	41910	
	Forecast Deviation - %	-0.6	-5.4	-7.9	-2.7	-1.2	-1.6	
Generation -	Hydro	12276	12276	12276	10777	10777	10844	
	Thermal	43582	43658	43725	39316	39316	39846	
	Other	4022	4057	4022	4268	4268	4280	
	Total	59880	59991	60023	54361	54361	54970	
Total Unavailable Generation *		6863	5901	5907	8281	13537	9791	
Net Firm Transfers - NWPP **		-4020	-4025	-3917	-2285	-1681	-1755	
	AZ-NM-SNV **	-6537	-6494	-6436	-5289	-5045	-5114	
	Total Net Firm Transfers	-10557	-10519	-10353	-7574	-6726	-6869	
Net Generation & Firm Transfers		63574	64609	64469	53654	47550	52048	
Margin Over Firm Loads - MW		7995	11404	16121	11252	8375	11448	
Margin Over Firm Loads - Percent		14.4	21.4	33.3	26.5	21.4	28.2	
ENERGY - GWH								TOTAL
Total Load		29186	28765	24386	23533	22268	23704	284951
	Forecast Deviation - %	1.0	-1.5	-8.7	-5.8	-4.9	-4.2	-2.8

* Includes Maintenance, Forced Outages, and Inoperable Capability.
** Minus (-) indicates transfer into WECC Region.

Table 28 - California-Mexico Power Area Estimated Peaks Demands, Resources, and Reserves 2006 - 2015

	SUMMER PEAK							Adverse Hydro Conditions		
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Month	AUG	AUG	AUG	AUG	AUG	AUG	AUG	AUG	AUG	AUG
Loads – Firms	56975	58144	59324	60520	61745	63002	64304	65612	66921	68259
Int. & Load Mgt	2062	2062	2062	2062	2062	2062	2062	2062	2062	2062
Total - MW	59037	60206	61386	62582	63807	65064	66366	67674	68983	70321
Growth from Previous Yr. - %	2.9	2.0.	2.0	1.9	2.0	2.0	2.0	2.0	1.9	1.9
Generation ± Transfers - MW	67844	69066	70295	71403	72644	73917	75239	76564	77889	76244
Maint./Inoperable Cap. - MW	1622	1622	1622	1502	1502	1502	1502	1502	1502	1502
Reserve Capability MW	9247	9300	9349	9381	9397	9413	9433	9450	9466	9483
Percent of Firm Peak Demand	16.2	16.0	15.8	15.5	15.2	14.9	14.7	14.4	14.1	13.9

Projected Average Annual Summer Compound Growth Rate (2005-2015) - 2.1%

	WINTER PEAK							Adverse Hydro Conditions		
	06-07	07-08	08-09	09-10	10-11	11-12	12-13	13-14	14-15	15-16
Month	DEC	DEC	DEC	DEC	DEC	DEC	DEC	DEC	DEC	DEC
Loads – Firms	41224	42084	42948	43813	44692	45595	46532	47474	48429	49415
Int. & Load Mgt	1310	1310	1310	1310	1310	1310	1310	1310	1310	1310
Total - MW	42534	43394	44258	45123	46002	46905	47842	48784	49739	50725
Growth from Previous Yr. - %	1.5	2.0	2.0	2.0	1.9	2.0	2.0	2.0	2.0	2.0
Generation ± Transfers - MW	58904	59101	59949	59949	60656	60839	61094	61344	62208	63225
Maint./Inoperable Cap. - MW	5832	4652	5564	5527	5661	5891	5593	5493	5493	5493
Reserve Capability MW	11848	12365	11437	10609	10303	9353	8969	8377	8286	8317
Percent of Firm Peak Demand	28.7	29.4	26.6	24.2	23.1	20.5	19.3	17.6	17.1	16.8

Projected Average Annual Winter Compound Growth Rate (2005/06-2015/2016) – 1.9%

Table 29 - California-Mexico Power Area Summary of Generation Additions (Summer Capability - MW)

Generation Type	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	10 Yr. Period	% of Total
Hydro - Conventional	2	0	0	0	0	0	0	0	0	0	2	0.1
Hydro - Pumped Storage	0	0	0	0	0	0	0	0	390	0	390	12.3
Steam - Coal	-1580	0	0	0	0	0	0	0	0	0	-1580	-50.0
Steam - Oil	0	0	0	0	0	0	0	0	0	0	0	0.0
Steam - Gas	-163	0	0	0	0	0	0	0	0	0	-163	-5.2
Nuclear	0	0	0	0	0	0	0	0	0	0	0	0.0
Combustion Turbine	-52	86	-5	0	0	0	0	0	0	0	29	0.9
Combined Cycle	1832	167	818	0	755	253	255	250	0	0	4330	137.1
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0.0
Internal Combustion	0	0	0	0	0	0	0	0	0	0	0	0.0
Other	50	36	16	0	0	50	0	0	0	0	152	4.8
Total	89	289	829	0	755	303	255	250	390	0	3160	100.0

Table 30 - California-Mexico Power Area Summary of Significant Generation Additions (Summer Capability)

AREA	PLANT NAME / UNIT NO. / LOCATION	UNIT TYPE	NET CAPABILITY MW SUMMER	NET CAPABILITY MW WINTER	PRIMARY FUEL FUEL TYPE	PRIMARY FUEL DELIV. METHOD	IN-SERVICE DATES	STAT	Cor U	COMMENTS
CISO	Shiloh Wind Proj 1, Solano Cnty	WT	40	40	WND		1-2006	V	C	Owner: PPM
CISO	Mountainview CC 4, San Bernardino	CC	504	518	NG	PL	1-2006	V	C	Developer: Edison/MVP
CISO	Mohave 1, Laughlin NV	ST	-1580	-1580	BIT	PL	1-2006	RT	C	
CISO	Santa Cruz LF, CA	OT	4	4	LFG		2-2006	V	C	
SMUD	Cosumnes CC 1, Sacramento CA	CC	500	500	NG	PL	3-2006	V	C	Developer: SMUD
TIDC	Walnut CC 1, Turlock CA	CC	269	269	NG	PL	3-2006	U	C	Owner: TIDC
CISO	Riverside ERC 1-2, Riverside CA	GT	96	96	NG	PL	4-2006	V	C	Owner: City of Riverside 48 MW
CISO	Riverside derate	GT	-96	-96	NG	PL	4-2006	V	C	self-generation plant derate
CISO	Palomar CC 1, Escondido CA	CC	559	559	NG	PL	4-2006	V	C	Developer: Sempra Energy
CISO	Hunters Point GT1, San Francisco	GT	-52	-52	DFO	TK	5-2006	RT	C	Unit to shut down 4-30-06
CISO	Hunters Point 4, San Francisco	ST	-163	-163	NG	PL	5-2006	RT	C	Unit to shut down 4-30-06
CISO	Chula Vista, CA	GT	44	44	NG	PL	6-2006	V	C	
CISO	Chula Vista derate	GT	-44	-44	NG	PL	6-2006	V	C	uncommitted resource addition
CISO	Escondido, CA	GT	44	44	NG	PL	6-2006	V	C	
CISO	Escondido derate	GT	-44	-44	NG	PL	6-2006	V	C	uncommitted resource addition
LDWP	Castaic 4, Castaic CA	PS	0	0	WAT		6-2006	A	C	Capacity increased by 13 MW
SMUD	Solano Wind 2A, Rio Vista CA	WT	6	6	WND		7-2006	P	U	First part of phase II 24 MW
LDWP	San Francisquito 2 #3, LA County	HY	2	2	WAT		11-2006	A	C	Capacity increased by 2 MW
WASN	Roseville CC 1, Roseville CA	CC	167	175	NG	PL	2-2007	P	U	Owner: City of Roseville
CFE	Pdte.Juarez GT 3, Tijuana Mexico	GT	86	86	NG	PL	3-2007	A	U	Repowering from 150 to 234 MW
LDWP	Castaic 5, Castaic CA	PS	0	0	WAT		5-2007	A	C	Capacity increased by 13 MW
LDWP	Pine Tree 1-80, Mohave CA	WT	36	36	WND		10-2007	P	U	Nameplate capacity = 120 MW
CISO	Otay Mesa CC 1, San Diego Cnty	CC	590	590	NG	PL	1-2008	U	U	Developer: Calpine
CFE	Mexicali II 1, San Luis Rio Col.	CC	228	228	NG	PL	3-2008	P	U	Includes 25MW solar supplement
LDWP	Castaic 3, Castaic CA	PS	0	0	WAT		4-2008	A	U	Capacity increased by 13 MW
SMUD	Solano Wind 2B, Rio Vista CA	WT	16	16	WND		7-2008	P	U	Second part of phase II 63 MW
MID	Hershey Cogen GT1, Modesto CA	GT	-5	-5	NG	PL	11-2008	D	U	Cogen contract ends
LDWP	Castaic 1, Castaic CA	PS	0	0	WAT		4-2009	A	U	Capacity increased by 13 MW
CFE	Baja California 2, unknown site	CC	255	255	NG	PL	4-2010	P	U	Generic resource acquisition
SMUD	Cosumnes CC 2, Sacramento CA	CC	500	500	NG	PL	7-2010	P	U	Developer: SMUD
CFE	Baja California 3, unknown site	CC	253	253	NG	PL	4-2011	P	U	Generic resource acquisition
SMUD	Solano Wind 3, Rio Vista CA	WT	50	50	WND		7-2011	P	U	Second part of phase II 200 MW
CFE	Baja California 4, unknown site	CC	255	255	NG	PL	4-2012	P	U	Generic resource acquisition
CFE	Baja California 5, unknown site	CC	250	250	NG	PL	4-2013	P	U	Generic resource acquisition
SMUD	Iowa Hill 1, El Dorado Cnty CA	PS	390	390	WAT		7-2014	P	U	Developer: SMUD

See the appendix for a description of the unit type codes, status codes, and the committed/uncommitted codes.

Transmission

The Western Interconnection transmission facilities are planned in accordance with the "NERC/WECC Planning Standards," which establishes performance levels intended to limit the adverse effects of each system's operation on others.

Information regarding the existing interconnected bulk power transmission system and the significant transmission facilities planned through the next ten years is compiled annually by the Council and provides the basis for this section.

As of January 1, 2006, the WECC interconnected bulk power system was comprised of 118,225 circuit miles of transmission. Significant additions during 2005 were the Scultz – Wautoma 500 kV line in Washington, the Teckla – Carr Draw 230 kV line in Wyoming and the Boise – Midpoint 230 kV line in Idaho. Figure 11 and Table 31 categorize existing transmission for the WECC region by voltage class and indicate that approximately 59 percent of the existing bulk power transmission is operated at a voltage class of 230 kV or above.

Figure 12 and Table 32 present information regarding the significant transmission additions planned for the 2006-2015 period. The planned transmission additions are categorized by voltage class, and the corresponding circuit miles are summarized for each of the four WECC areas. Significant transmission additions include interconnections to the system from major generation sources, interconnections between control areas, and transmission lines important to interconnected system operation. The total net transmission circuit miles planned for the 2006-2015 period represents a 5.2 percent increase over the existing circuit miles as of January 1, 2006. Approximately 58 percent of the significant net circuit mile additions planned are of the 345 kV class or higher.

Ten-year projected transmission additions in the 500 kV AC voltage category for the 2006-2015 period have increased by 294 circuit miles compared to the projections reported last year. The increase is due to the planned projects in Alberta, California and Arizona. Projections in the 345 kV AC voltage category have increased by 228 circuit miles compared to the projections reported last year. The increase is due to planned projects in the Arizona, Nevada and Rocky Mountain areas. Projections in the 230 kV line category have increased by 290 miles compared to the projections reported last year. The increase is due to planned projects in several WECC areas.

Significant transmission additions reported for the next ten years include 2,276 miles of 230 kV transmission lines, 950 miles of 345 kV, and 2,600 miles of 500 kV. Some of the noteworthy additions in each voltage category are highlighted on the map on the following page.

The planned transmission additions for the WECC region through the year 2015 reflect a continuing interest in the development and strengthening of interconnections to enhance system reliability, to increase the capability for economy energy transfers, and to enable diversity in exchanging power between areas with different seasonal peak demand and energy requirements.

Transmission additions in the 500 kV category represent 42 percent of the planned significant additions. By the year 2015 the 500 kV transmission system mileage will have increased by approximately 16 percent.

To help in mitigating major unscheduled flow problems, several utilities have cooperated in the installation of phase-shifting transformers throughout the WECC region transmission system. The installation of DC links in Canada, Colorado, New Mexico, Nebraska, and southeastern Montana permit the transfer of electricity between WECC and two adjacent councils: Southwest Power Pool and Midwest Reliability Organization.

In effect, the WECC system is being developed to ensure the efficient and economical use of resources and at the same time ensure reliability and environmental compatibility.

Figures 13 and 14 illustrate WECC non-simultaneous transfer capabilities for 2006 and 2010 respectively. These transfer

capabilities represent the total capability of the various interconnections of the existing system and the planned 2010 system. It should be recognized that the transfer capability of an interconnection is not a single value as it is dependent upon system conditions, and the simultaneous import capability of a given area may be less than the sum of the individual interconnection capabilities. Each transfer capability depicted has been determined for a specific system condition. Transfer capabilities between the WECC areas are generally adequate to accommodate the existing and anticipated firm power schedules. However, there are limitations that persist in accommodating all desired economy/surplus power transfers.

In some instances, dependence has been placed on complex remedial measures to enable increased power transfer levels for use of the region's most cost-effective resources. The reliability and security of these remedial action schemes are reviewed periodically and updated when necessary.

Transmission Additions 2006-2015

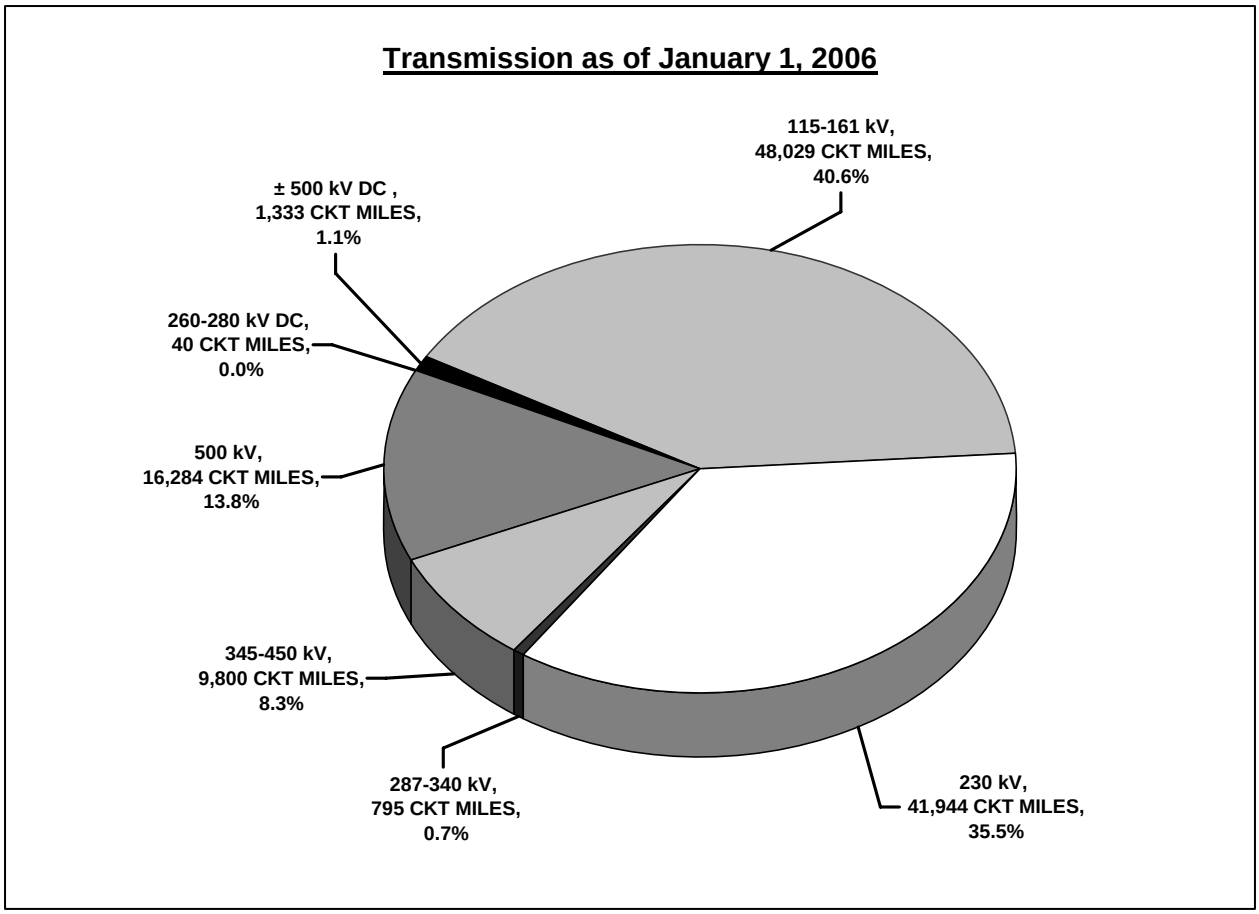


Figure 11

Table 31 - Transmission as of January 1, 2006
(Circuit Miles)

Voltage	Northwest Power Pool Area	Rocky Mountain Power Area	Arizona New Mexico So. Nevada Power Area	California Mexico Power Area	WECC Total	% of Total
115 - 161 kV	27,396	6,085	4,978	9,570	48,029	40.6%
230 kV	20,844	4,939	3,602	12,559	41,944	35.5%
287 - 340 kV	444	0	0	351	795	0.7%
345 - 450 kV	4,358	982	4,460	0	9,800	8.3%
500 kV	9,740	0	2,209	4,335	16,284	13.8%
260 - 280 kV DC	40	0	0	0	40	0.0%
±500 kV DC	264	0	0	1,069	1,333	1.1%
Total	63,086	12,006	15,249	27,884	118,225	100.0%
Percent of WECC Total	53.4%	10.2%	12.9%	23.6%	100.0%	

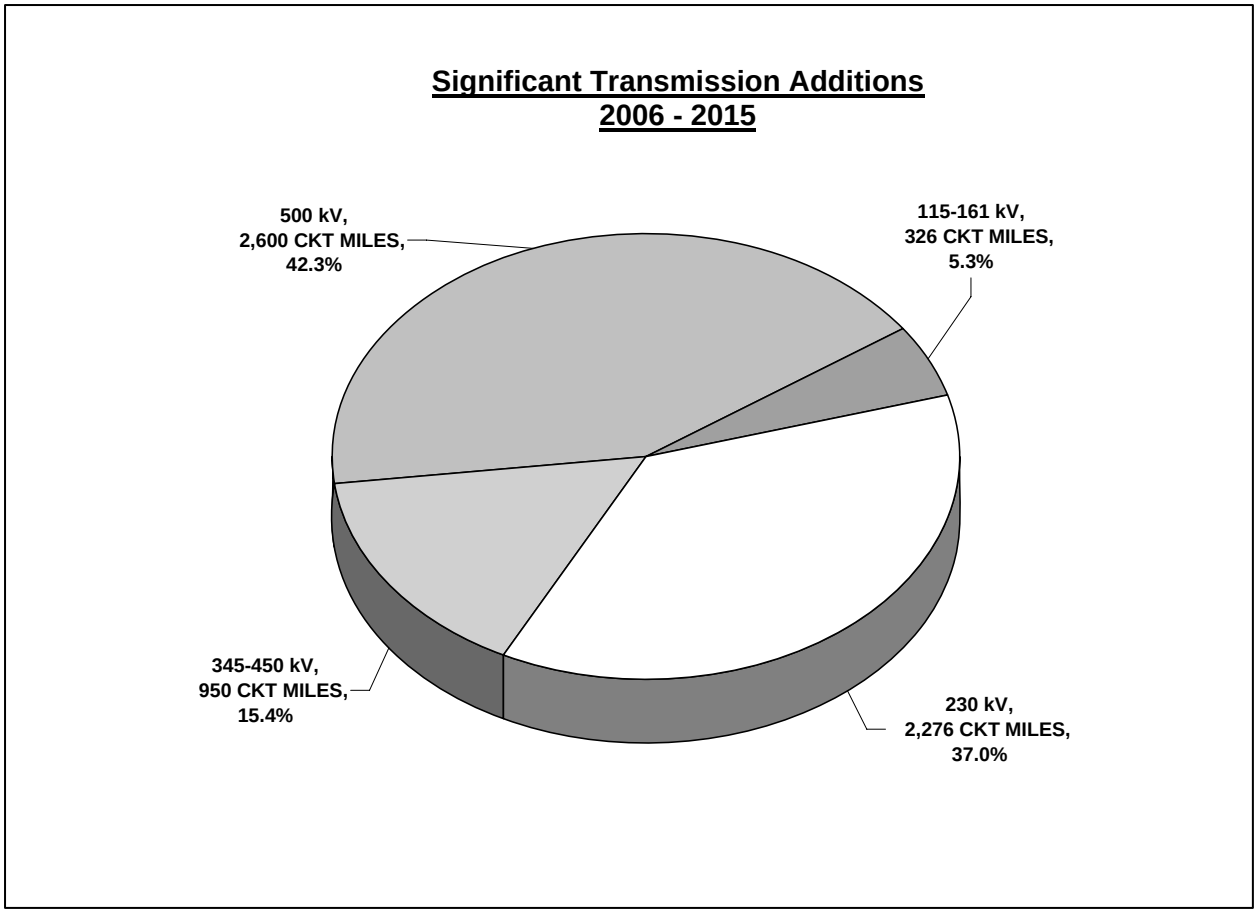


Figure 12

Table 32 - Summary of Significant Transmission Additions (Net) 2006 - 2015 (Circuit Miles)

Voltage	Northwest Power Pool Area	Rocky Mountain Power Area	Arizona New Mexico So. Nevada Power Area	California Mexico Power Area	WECC Total	% of Total
115 - 161 kV	44	245	24	13	326	5.3%
230 kV	677	484	486	629	2,276	37.0%
287 - 340 kV	0	0	0	0	0	0.0%
345 - 450 kV	98	250	602	0	950	15.4%
500 kV	928	0	1,167	505	2,600	42.3%
260 - 280 kV DC	0	0	0	0	0	0.0%
±500 kV DC	0	0	0	0	0	0.0%
Total	1,747	979	2,279	1,147	6,152	100%
Percent of WECC Total	28.4%	15.9%	37.0%	18.6%	100.0%	

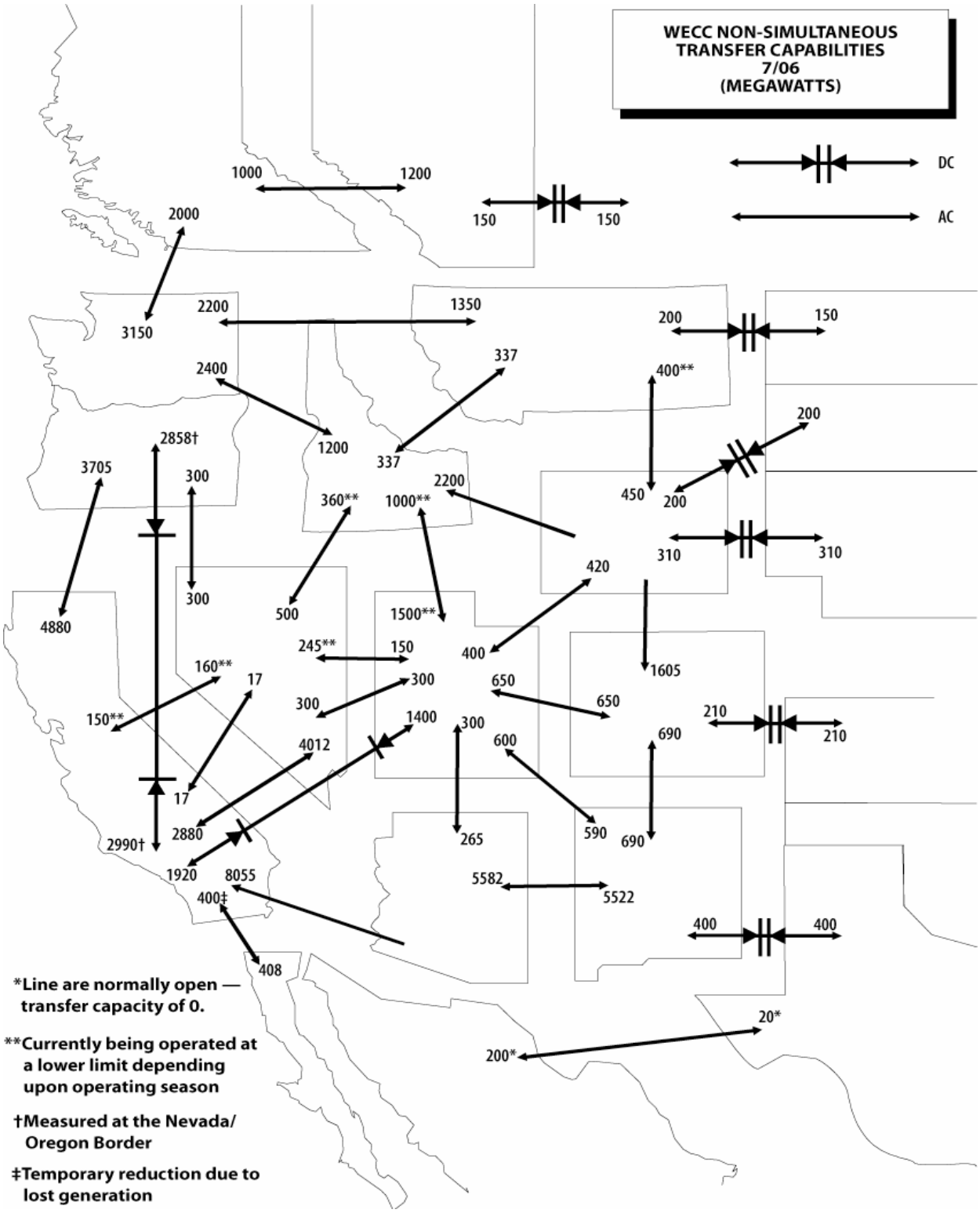

WECC NON-SIMULTANEOUS
TRANSFER CAPABILITIES
7/06
(MEGAWATTS)
DC
AC
1000
1200
150
150
2000
3150
2200
1350
200
150
2400
337
400**
200
2858†
1200
337
3705
300
2200
450
200
360**
1000**
310
310
420
300
500
1500**
4880
245**
150
400
1605
160**
17
300
650
650
300
150**
1400
300
210
210
4012
600
690
17
2880
265
590
690
2990†
1920
8055
5582
5522
400‡
400
400
408
20*
200*
*Line are normally open — transfer capacity of 0.
**Currently being operated at a lower limit depending upon operating season
†Measured at the Nevada/ Oregon Border
‡Temporary reduction due to lost generation

Figure 13

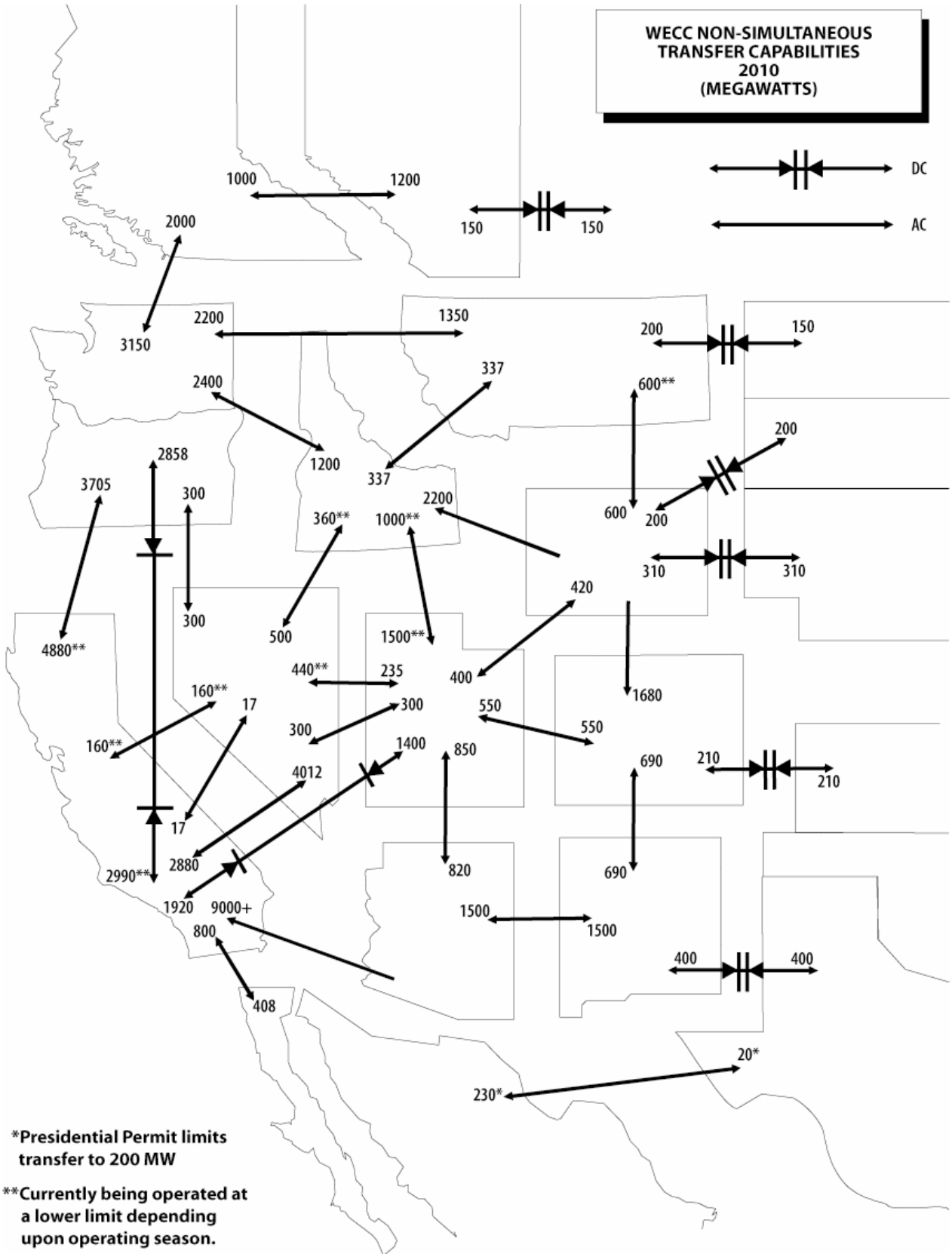

WECC NON-SIMULTANEOUS
TRANSFER CAPABILITIES
2010
(MEGAWATTS)
DC
AC
1000
1200
150
150
2000
3150
2200
1350
200
150
2400
337
600**
1200
337
2858
200
3705
300
2200
600
200
360**
1000**
310
310
420
300
500
1500**
4880**
440**
235
400
1680
160**
17
300
550
300
550
160**
1400
850
690
210
210
4012
17
2880
820
690
2990**
1920
9000+
1500
1500
800
400
400
408
20*
230*
*Presidential Permit limits
transfer to 200 MW
**Currently being operated at
a lower limit depending
upon operating season.

Figure 14

Appendix

Historical Peak Demand Calendar Year Data (Thousands of MW)

	Northwest Power Pool Area	Rocky Mountain Power Area	Arizona New Mexico So. Nevada Power Area	California Mexico Power Area	WECC Total
1982	43.7	5.41	8.71	35.8	84.1
1983	46.7	5.59	8.90	37.5	88.4
1984	44.8	5.70	9.38	40.9	89.2
1985	45.3	5.74	10.07	42.7	93.2
1986	42.6	5.90	10.35	41.6	91.8
1987	44.5	6.02	12.41	40.8	94.0
1988	45.9	6.10	13.24	44.8	101.9
1989	52.7	6.33	14.47	43.0	103.0
1990	56.1	6.79	14.99	47.8	110.0
1991	51.9	6.49	14.45	44.3	107.9
1992	51.8	6.38	15.67	48.2	112.3
1993	54.1	6.73	15.96	46.8	111.0
1994	53.0	6.96	17.13	49.6	115.8
1995	52.6	7.27	17.89	49.2	117.4
1996	57.2	7.43	18.70	51.3	123.4
1997	55.3	7.93	19.03	53.2	124.9
1998	60.0	7.98	20.43	55.4	131.7
1999	56.0	7.64	19.95	53.1	129.1
2000	56.2	8.59	21.72	51.2	130.9
2001	52.6	9.33	23.36	48.4	125.0
2002	52.1	9.89	24.22	52.2	136.1
2003	53.9	10.49	25.55	53.1	139.9
2004	58.9	10.40	25.63	55.9	141.1
2005	60.4	11.09	27.97	57.4	149.1

Historical Energy Load Calendar Year Data (Thousands of GWh)

	Northwest Power Pool Area	Rocky Mountain Power Area	Arizona New Mexico So. Nevada Power Area	California Mexico Power Area	WECC Total
1982	234.8	31.28	42.72	188.0	496.8
1983	235.3	31.81	44.08	188.0	499.1
1984	250.9	33.09	46.70	205.2	535.9
1985	257.3	35.40	50.64	209.7	553.1
1986	253.4	34.82	51.46	216.3	556.0
1987	262.4	35.36	63.42	214.6	575.7
1988	280.2	37.03	67.48	223.3	608.1
1989	291.4	38.02	71.25	229.1	629.9
1990	301.1	38.49	74.54	236.7	650.8
1991	305.2	38.44	75.71	230.6	649.9
1992	307.6	39.99	77.90	236.7	662.2
1993	312.8	40.55	80.42	235.6	669.4
1994	316.3	42.05	86.05	243.7	688.1
1995	318.3	43.42	87.66	240.5	689.9
1996	334.2	43.92	94.72	248.7	721.6
1997	332.1	47.08	98.53	256.9	734.6
1998	342.9	48.07	97.36	254.6	742.9
1999	348.9	46.28	96.95	262.3	754.4
2000	354.6	51.50	104.42	275.6	786.1
2001	324.1	54.46	111.31	269.0	758.8
2002	342.7	56.11	115.66	277.6	792.1
2003	340.6	56.83	120.57	277.1	795.2
2004	347.3	57.21	122.94	288.6	816.1
2005	360.9	59.19	126.54	285.0	831.6

Note: The peak demands are noncoincidental. Some areas in WECC are winter peaking, others are summer peaking. For this reason, the sum of the area peak demands may not equal the peak demand for the WECC region.

All numbers in these tables have been rounded off. Therefore, the sum of the energy loads for the individual areas may not be equal to the total WECC energy load.

Prior to 1997, the Southern Nevada reporting-area data were included in the California sub-area data. The Arizona-New Mexico-Southern Nevada Power Area and California-Mexico Power Area data, prior to 1987, have not been adjusted for the Southern Nevada reporting-area change.

Unit Type, Status, and Committed/Uncommitted Codes

Unit Type	Code
Steam Turbine - Non Nuclear	ST
Steam Turbine - Nuclear	NP
Steam Turbine - Nuclear	IC
Combustion Turbine (Gas Turbine)	GT
Hydro - Conventional	HY
Hydro - Pumped Storage	PS
Combined Cycle - Steam Portion	CA
Combined Cycle - Combustion Turbine Portion	CT
Combined Cycle - Single Shaft	CS
Combined Cycle - Total Unit	CC
Fuel Cell	FC
Solar Power - Photovoltaic	PV
Wind Power	WT
Compressed Air Energy Storage	CE
Geothermal	GE
Not Available	NA
None of the above (Describe in Comments)	OT

Status	Code
Planned for installation but not under construction.	P
Regulatory approval pending but not under construction. Started site preparation	L
Regulatory approval received but not under construction.	T
Under construction, less than or equal to 50% complete	U
Under construction, greater than 50% complete.	V
Construction complete, but not yet in commercial operation.	TS
Generating unit capability increased (rerated or relicensed).	A
Generating unit capability decreased (rerated or relicensed).	D
Generating unit put in inactivated or mothballed status.	M
Generating unit returned to service from inactive or mothballed status	RA
Generating unit permanently removed from any service.	RT
Existing generator planned for conversion to another fuel or energy source.	FC
Proposed for repowering.	RP
None of the above. Explain in the comments.	OT
Planned generator indefinitely postponed.	IP

Committed/Uncommitted	Code
Committed – under construction with reported in-service dates before July 2007 (or July 2008 if coal-fired.)	C
Uncommitted – not under construction or under construction with reported in service dates after July 2007 (or July 2008 if coal-fired.)	U

Other Available WECC Publications

Existing Generation and Significant Additions and Changes to System Facilities

Information Summary

Summary of Estimated Loads and Resources

Portions of WECC FERC No. 715 Filing

WECC Reliability Criteria

PLEASE VISIT WECC'S WEBSITE AT WWW.WECC.BIZ

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Western Electricity Coordinating Council

2008 Power Supply Assessment

5 November 08

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EXECUTIVE SUMMARY

Summary

The 2008 Western Electricity Coordinating Council (WECC) Power Supply Assessment (PSA) is an evaluation of generation resource reserve margins (in MW) for the WECC summer and winter peak hours for the forecast period 2009 through 2017. This PSA also includes an energy assessment (GWh) for the Pacific Northwest, prepared by Bonneville Power Administration (BPA) and the Northwest Power and Conservation Council (NWPCC)[1]. The PSA presents the results of the assessment that was conducted by the WECC staff during the second quarter of 2008, based on data that was requested in the fall of 2007 and submitted by WECC member utilities in the winter of 2007-08.

The capacity assessment identifies sub-regions within WECC that have the potential for electricity supply shortages based on reported demand, resource, and transmission data. The Supply Adequacy Model (SAM)[2] used to conduct the assessment includes 26 zones, which are aggregated to make the seven sub-regions shown in the graphs. The aggregation of zones into sub-regions is shown in Table 4 on page 7. The Power Supply Margin by sub-region, shown in the graphs, is a measure of a sub-region's ability to meet its firm and non-firm load requirements, including a specified reserve amount, with resources in the sub-region and imports from other sub-regions, as calculated by SAM. A Power Supply Margin equal to or greater than zero denotes that the target, including the reserve margin, was met. A Power Supply Margin less than zero indicates that the sub-region's native generation and calculated imports were less than the target amount.

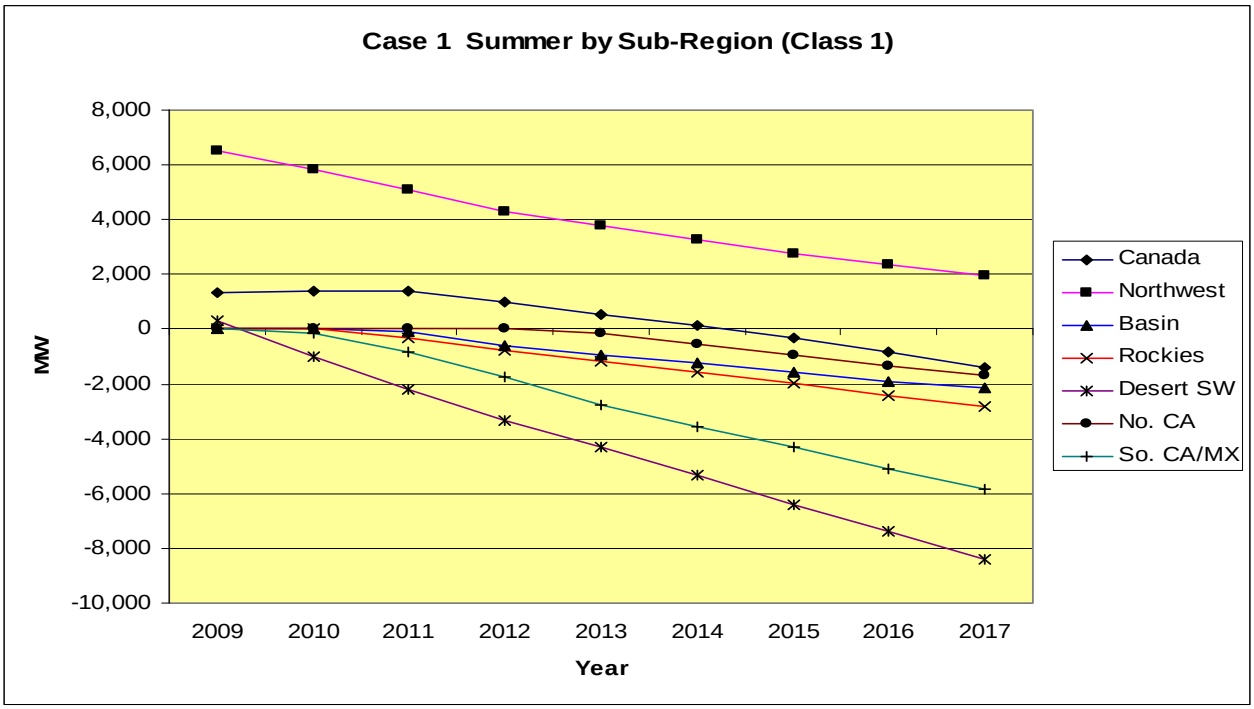
The graphs for both summer and winter Power Supply Margins, Cases 1 and 2, respectively, portray a need for future resources beyond those already under active construction and after accounting for the potential imports from the sub-regions with capacity surpluses. Resources have been proposed to meet a portion of these needs; a significant number of these are not under active construction although they are undergoing regulatory review; others, as noted later in this Executive Summary and in Attachment 8 have not yet been proposed for regulatory review. It is also clear that the sub-region Power Supply Margin varies significantly throughout the WECC region.

Note that the summer and the winter analyses for the Northwest sub-region may not adequately capture the limitations on the ability of the Northwest hydro system to sustain capacity output levels beyond a single hour. Because of this limitation, the reported surpluses, both to meet the Northwest sub-region's load and for potential export to other sub-regions of the West, should be considered unrealistically high. Loads and Resources Subcommittee (LRS) members report that these surpluses are not available for advance heavy load-hour contract commitments in summer months. Additionally there is no indication that transmission will be built solely to allow this limited duration surplus to be used in the sub-regions with shortages.

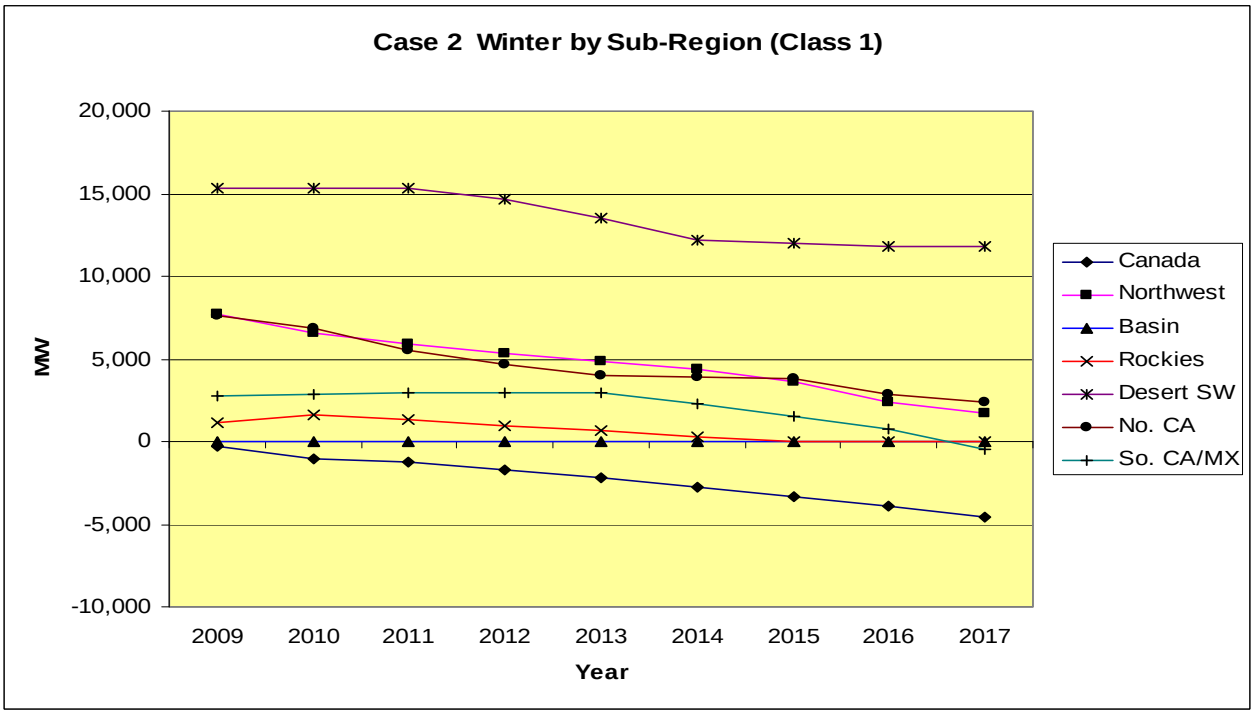
Results that indicate deficits below target reserve levels in later years of the assessment period are not forecasts of shortages. Rather, they are an indication that proposed resources need to be brought along through regulatory approval to construction at appropriate speed. At some point,

[1] See Attachment 7.
[2] The California Energy Commission (CEC) developed the Supply Adequacy Model.

Graph 1 – Sub-Regional Resource Surplus/Deficit Summer Period



Graph 2 – Sub-Regional Resource Surplus/Deficit Winter Period



the study results shift from an evaluation of Power Supply Margin to a determination of future needs and investment opportunities.

As summarized in Tables 1 and 2, a total of eleven cases are included in the 2008 PSA. Each case evaluates whether there are sufficient resources (e.g., local generation including near-term

additions and transmission import capacity) in each of the 26 defined zones to meet the peak load forecast requirements plus a reserve requirement. The cases are distinguished by season, by the amount of new generation that is included in addition to existing resources, by the location and intensity of the extreme weather impact and by the reserve requirement that it tries to meet.

Table 1 provides a description of the cases that were developed using the different seasons, margin definitions and amounts of new resources. The definitions of the resource classes are found on pages 4 and 5.

Table 1 – Case Description

Case	Season	New Resources	Margin
1	Summer	Class 1	Building Blocks
2	Winter	Class 1	Building Blocks
3	Summer	Classes 1 through 3	Building Blocks
4	Winter	Classes 1 through 3	Building Blocks
5	Summer	Class 1	15%

Table 2 provides a description of the temperature sensitivities that were studied. These sensitivities were only studied for a single season, summer 2011 or winter 2011–12, as appropriate. Because these studies were intended to examine the effect of weather stresses beyond what were planned for in the Building Block Reserve Margin, the test margin was modified to exclude the reserve for additional forced outages and the 1–in–10 weather reserve component, leaving only the reserve components for contingencies and regulation that are actually required in operating reserves.

Table 2 – Temperature Sensitivity Cases

Temperature Sensitivities: Modified Building Blocks - 2011 only			
Case	**Season**	**New Resources**	**Temperature Definition**
6	Summer	Class 1	July 24, 2006 temperature, 2011 demand
7	Summer	Classes 1 through 3	July 24, 2006 temperature, 2011 demand
8	Summer	Class 1	Calif., Ariz., S. Nev.: 1-in-20 Rest of West: 1-in-10
9	Summer	Classes 1 through 3	Calif., Ariz., S. Nev.: 1-in-20 Rest of West: 1-in-10
10	Winter	Class 1	Canada, NW, Basin, N. Calif.: 1-in-20 Rest of West: 1-in-10
11	Winter	Classes 1 through 3	Canada, NW, Basin, N. Calif.: 1-in-20 Rest of West: 1-in-10

There are several noteworthy changes from the 2007 PSA to the 2008 PSA. They are highlighted below and described in more detail elsewhere in the summary and the body of the report.

- The reserve margin calculation, while using the same building block concepts as last year, used slightly different calculations and/or data, resulting in lower reserve requirements than in 2007.

- The resource classes for new generation were modified from last year's classes to include one more year in the time window, to attempt to further discriminate among plants not yet under construction according to the status of their request for transmission service, and to better track new generation categories used by NERC in its resource reports.

- An additional sensitivity discussion on the potential effect of the California State Water Resource Board's restrictions on once-through cooling has been added.

The case and sensitivity variables are described below.

- **Reserve Margin**: The 2008 PSA uses a building block approach to calculate the reserve margins, developed from an evaluation of a number of uncertainties facing load serving entities. The building block approach has four elements: contingency reserves, regulating reserves, reserves for additional forced outages, and reserves for 1–in–10 weather events[3]. Separate building block values were developed for each Balancing Authority and then aggregated by sub-regions for the analysis. The sub-regions and the values that were used are shown in Table 4, below.

- **Temperature Sensitivity**: The temperature sensitivity cases looked at the impact on available capacity for the entire Western Interconnect when 1–in–20 year temperature demand occurred in different regions of the interconnection. In these temperature studies, not all regions have 1–in–20 demand increases. The zones in the regions that did not have demand increased to a 1–in–20 temperature level were increased to a 1–in–10 temperature demand to reflect the potential for increased demand throughout the Interconnect. In addition, a case to look at the impact of a recurrence of an extreme temperature event such as the one on July 24th 2006 was created.

- **New Generation**: The following categories were defined for new resources additions (reported as of December 2007). Class 1 additions were used in all of the cases. Five of the cases also included Class 2 through 3 additions. Class 4 and 5 additions were listed for purposes of categorizing all reported projects in a manner consistent with NERC categories, but they were not included in any of the analyses. All new generation resources reported, including those in Classes 4 and 5, are displayed in Attachment 8.

    - *Class 1*: Generation additions/retirements that were reported to be under active construction as of the reporting date of December 2007 and are projected to be in-service prior to January 2012.

    - *Class 2*: Generation additions/retirements that were reported as having received all regulatory approvals, with a signed interconnection agreement, with an expected in-service date prior to January 2014. This class includes resources that were expected to be in service as early as Class 1 resources but did not meet the test of

[3] See "Building Block Guideline for Reserve Margin" on page 14 for definitions and details.

being under construction, or for resources that may not be completed/retired before the January 2012 date.

- *Class 3*: Generation additions/retirements that were reported to be at least undergoing regulatory review and at least a facility study completed, with an interconnection agreement in active negotiation, with an expected on-line date prior to January 2014.

- *Class 4*: Generation additions/retirements that were reported which have met the NERC criteria for Planned Resources[4]. NERC has included resources in their Planned category which are included in a sponsoring organization's capital budget, or have received Board of Director approval. The Loads and Resources Subcommittee created this class to allow consistent reporting of resources, however, these resources are not included in any of the PSA cases.

- *Class 5*: Generation additions/retirements that were reported which have met the NERC criteria for Proposed Resources[5]. NERC has included resources in their Proposed category which have been identified and announced through a Corporate announcement or have been included in an integrated resource plan. Again, the Loads and Resources Subcommittee created this class to allow consistent reporting of resources, but these resources are not included in any of the PSA cases.

Table 3 is a synopsis of the results showing the first year of deficiency for each sub-region by case. A deficit condition is an indication that a sub-region was unable to meet its load requirements, plus the applicable planning reserve margin, given the parameters for that case and assuming the non-contracted transfers quantified by the model actually occur. The deficit amount is the net shortage that the model is showing for the sub-region. The "year of first deficit" could also be considered as the year that additional resources (besides those already included in the analysis) must be in-service to avoid deficiencies against the reserve margin. Resources could include additional generating capacity, or development of new energy efficiency or demand response programs that are not included in the load forecasts. Note also the effect of looking only at required operating reserve levels and normal weather demand, shown on Page 24, in postponing load-service problems under expected conditions.

It should be noted that the decision of which resources to include in the various case studies can affect the timing of when deficits occur in the sub-regions. The case studies in the 2008 PSA use only resources that will be in-service prior to January 2012, for resources that are currently under construction, or January 2014, for resources that are going through a regulatory review process. The LRS elected to limit the planned additions to this subset of resources due to a higher confidence factor that projects in Classes 1–3 have a greater likelihood of being built. The LRS also realizes that limiting the resources included to this subset can, and does, exclude many short

[4] *NERC Planned Capacity:* This category is for capacity which has achieved one or more of the following milestones: I) Construction has started, II) At least one of the following regulatory permits approved: a) Site permit, b) Construction permit, or c) Environmental permit, III) Corporate management has approved at least one of the following: a) Included in a capital budget or b) BOD approved.

[5] *NERC Proposed Capacity:* This category includes generation that is not in a prior listed category, but has been identified through one or more of the following sources: I) Corporate announcement, II) Included in integrated resource plan, III) Generator Interconnection Queues and IV) Interconnection study requested.

lead-time approval and construction projects, such as wind or small scale solar. As utilities adjust their procurement processes to rely upon renewable resources to a greater extent, in compliance with various state Renewable Portfolio Standards (RPS), and to rely less on highly visible, central station projects, the shortcomings of the current data collection process become more visible. The current process does not capture how short lead-time projects will be developed. Methods that link renewable generation development to transmission commitments may be one promising approach.[6] It is the intent of the LRS to address this classification limitation in future PSAs.

Table 3 - Year of First Deficit and Deficit Amount (MW)

Sub-Region	Case				
	1	2	3	4	5
	Summer Class 1	Winter Class 1	Summer Class 1-3	Winter Class 1-3	Summer 15% Class 1
Canada	2015 -336	2009 -301	2015 -238	2009 -301	2013 -88
Northwest					
Basin	2011 -86		2012 -326		2010 -133
Rockies	2011 -345		2012 -245		2009 -639
Desert Southwest	2010 -978		2010 -640		2009 -244
No. California	2013 -145		2013 -141		2013 -234
So. California/Mexico	2010 -138	2017 -433	2010 -138	2017 -325	2010 -124

The results for the eleven cases are aggregated to seven sub-regions to mitigate modeling limitations and to maintain load forecast confidentiality in years two and three of the forecast period as required by Appendix B of the WECC Information Disclosure Policy. The surplus or deficit amount is the sum of the surpluses and deficits across all of the zones in the sub-region. A deficit does not necessarily indicate that all of the zones in the sub-region are deficit; a surplus does not mean that all zones are surplus, as a surplus zone may mask a deficit in an adjacent zone, such as occurs within the Canada sub-region. Table 4 below shows the SAM zones for each sub-region[7].

Table 4 also shows the Building Block Reserve Margin values that were used for the sub-regions in the analysis. The margin calculation for the 2008 PSA used the same four elements as last years margin, however this years results are about 1% lower. The difference is due to the use of a different data set for calculating the forced outages rate, and a new calculation for the Contingency Reserve. Last year's calculation of the forced outages rate averaged 3.24%, while this year's calculation averaged 2.59%. The other factor creating the lower margin is the proposed change to

[6] As an example, Bonneville Power Administration recently concluded the first phase of its Network Open Season (NOS) process. This resulted in Precedent Transmission Service Agreements being signed with the developers of 4,716 MW of wind resources. Further, the California Independent System Operator has received FERC approval for development of a transmission line in the Tehachipi area of Central California expressively to support wind energy projects required to satisfy California's RPS requirements. While the amount can be debated, some build out of wind generation interconnecting to this transmission line is certain, even though specific projects may not be identified at this time.

[7] More detail on the SAM zones or "bubbles" is giving in Attachment 2.

the Contingency Reserve Standard. The 2007 PSA used the MORC calculation for reserves which averaged 6.3%, and the average under the new calculation was 6.0%.

Table 4 – SAM Zones and Building Block Margins

Sub-Region	SAM Zones Included in Sub-Region	Summer Margin	Winter Margin
Canada	British Columbia, Alberta	11.3%	13.2%
Northwest	Pacific Northwest, COB, Montana	14.3%	15.8%
Basin	Idaho, Northern Nevada, Utah, Intermountain Power Project	12.2%	11.7%
Rockies	Colorado East, Colorado West, Wyoming	11.8%	13.4%
Desert Southwest	Arizona, New Mexico, Southern Nevada, Imperial Irrigation District, Four Corners, Palo Verde	13.3%	12.8%
Northern California	Northern California, Central California, San Francisco, SMUD	14.7%	10.5%
Southern California/Mexico	Southern California Edison, San Diego Gas & Electric, LADWP, Comision Federal de Electricidad (CFE)	15.7%	11.4%
WECC Total		13.7%	12.9%

It is important to note that the values for reserve margins used in the PSA are NOT the values used by individual Load Serving Entities (LSEs) or their regulators or local governing boards to evaluate their individual resource adequacy. Moreover, they are not intended to supplant any of those values. There is at least one sub-region which is a competitive wholesale market for which there is no mandated reserve margin. Attachment 6 has more detail on this issue.

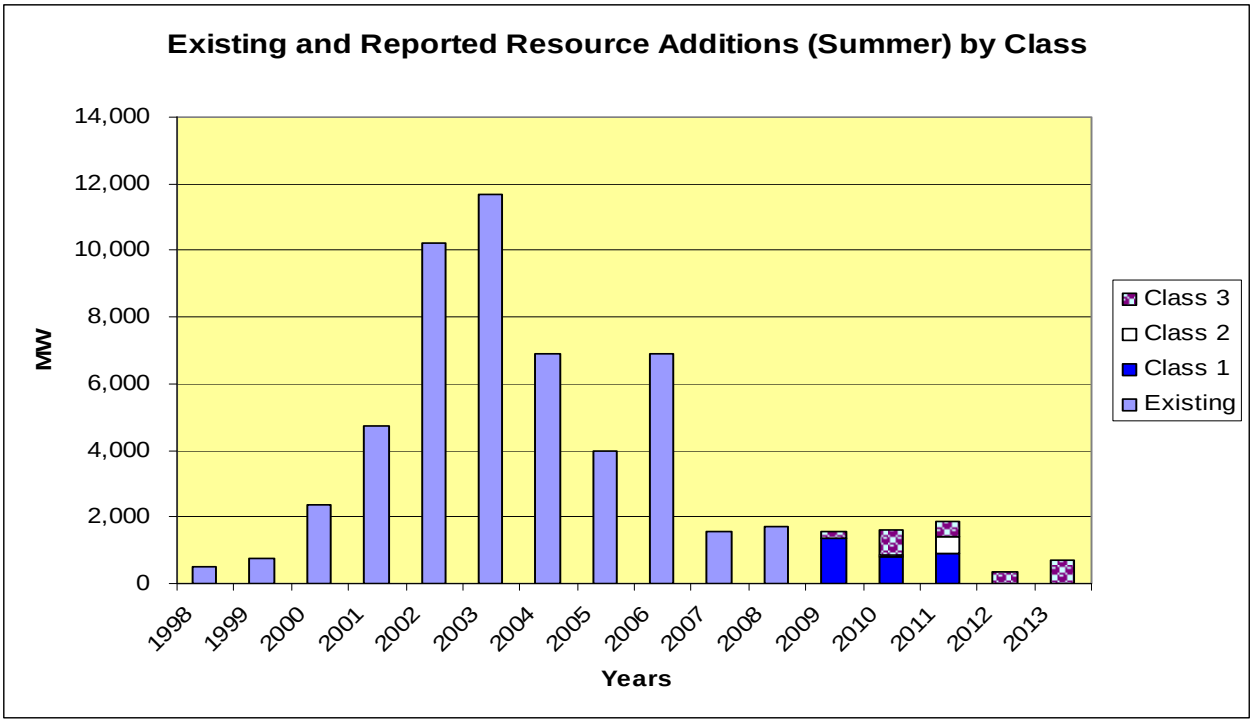
Graph 3 shows projected net resource summer additions from 2009 through 2013, using the resource definitions described earlier. Class 1 additions are planned projects that are under active construction and projected to be completed by January 2012. Class 2 additions are units that have received all regulatory approvals, with a signed interconnection agreement and are expected to be in service by January 2014. Class 3 additions are units which are at least undergoing regulatory review with at lease a facility study completed, undergoing active negotiation for an interconnection agreement, with an expected in service date before January 2014. Class 4 and 5 additions (which are not shown in the graph and were not included in the 2008 PSA analysis) capture all other reported proposed projects. More information about Class 4 and 5 resources is shown in Table 7 on page 17 and in Attachment 8.

The 2008 PSA cases include load forecasts for the full term of the PSA studies (2009–2017). Forecasts for continued increases in new generation resources and/or transmission capacity, reported in the winter of 2007–08, based on late 2007 data, include future new generation projects ranging from new projects that are being contemplated to new projects that are nearing completion.

For this analysis, summer wind turbine capacity was derated, on average, based on utility submissions, to approximately 16% of nameplate capacity, and winter wind capacity was derated to approximately 10% of nameplate capacity. These derates are reflected in Graph 3 and Attachment 8. The analysis of the appropriate capacity value for wind projects, particularly in

geographically diverse developments, is still ongoing in a number of forums in the West[8]. The results will be used to inform future adequacy evaluations[9].

Graph 3 - Existing and Reported Resource Additions



The 2008 PSA also includes an energy assessment for the Pacific Northwest (PNW), which is a part of the Northwest sub-region. BPA and the NWPCC plan to continue their work with energy assessments in the future. Attachment 7 describes the PNW energy assessment.

[8] A CAISO study of the extreme conditions of July 2006 found that during the five day period of July 21–26, 2006, that wind capacity during the peak hour averaged 12% of nameplate capacity on an integrated energy basis. During specific days of this period, wind performance during the peak hour ranged from 6% to 23% of nameplate capacity on an integrated energy basis. CAISO, March 2007.

[9] A sensitivity analysis using 0% capacity value was done, but given the low base capacity value (16%) and the limited wind penetration in Classes 1 through Class 3, the effect was minor. In future years, the sensitivity to this value will be substantially more, with expected wind penetrations under Renewable Portfolio Standards, and the importance of the ongoing analysis of this variable will be correspondingly high.

Caveats--Observations--Recommendations

Among the important caveats (Items 1–4), observations (Items 5–7), and recommendations (Items 8–10) that should be considered on reviewing these results are the following:

1. The analysis is based on loads and resources (L&R) data submitted in December 2007 and February 2008. The reported data was "locked" on March 31, 2008, and project changes reported to WECC after the data was locked were not included in the studies. For instance, it does not appear that the two Holcomb coal plants that were reported by WACM will be constructed by the time reported. However, this was learned after the data was locked and the qualifying unit was included in these studies. SRP has announced plans for several natural gas generating units, but these additions were announced after the data was locked and therefore were not included in these studies.

2. The assessment is based on the physical ability of the interconnection to supply all loads regardless of contractual obligations. This means that the model uses non-contracted resources to meet system demand during peak hours of the importing sub-regions, as well as using economic relationships to calculate transfers between zones within the assigned limits. In reality, the assessment results may be difficult to duplicate in the actual operational environment. System operation for contract obligations and other conditions could adversely affect the availability of resources, and could impact the amount and timing of supply deficiencies in specific zones.

3. The Loads and Resources Subcommittee recognizes that the results of this assessment may differ from the results of similar assessments by other parties.

4. Despite attempts to achieve uniform reporting through the L&R reporting instructions, there are known variations among the critical areas that can create ambiguities; the methods used to de-rate hydro generation from its nameplate to adverse capacity are a good example.

5. It is logical to expect more generation projects being added and existing plants being retired as needed in the future. <u>At some point, the study results shift from a determination of Power Supply Margin to an estimate of future resource needs.</u>

6. Using non-coincidental demands aggregated together from independent sources overstates the simultaneous demand. Preliminary studies indicate that the simultaneous combined peak demand for WECC is lower by 2% to 4%, compared to the non-simultaneous demand. However, some large sub-regions such as California may peak at a different time than was assumed for this assessment.

7. Surplus generation in the Pacific Northwest was stranded, but neither the summer nor the winter analysis for the Northwest sub-region fully captures the limitations on the ability of the hydro system to sustain output levels beyond a single hour. The reported Northwest surpluses, both for Northwest sub-region's load and for potential export to other sub-regions of the West, are unrealistic. This problem has been recognized for several years, and the PNW is getting closer to a widely accepted solution.

8. The effects of fuel diversity and availability should be modeled in future assessments. Improved analyses should evaluate the impact of fuel shortages due to fuel supply interruptions or demand spikes.

9. Expanding the energy assessment to other sub-regions and zones, where relevant, is a goal for the future. It is expected that the data and manpower requirements for energy assessments could be higher than for this peak hour capacity assessment. A more sophisticated model would also be needed. This is included in the LRS future work plan.

10. The impact of a competitive wholesale market design on Power Supply Margin assessments should be considered in the determination of supply shortfalls. While it is important to the effective functioning of the market that opportunities for investment in new generation be identified, recognition needs to be given to the ability of the market to respond in the timing horizon covered by this Power Supply Assessment.

2008 Power Supply Assessment

Purpose and Background

The WECC PSA evaluates the Power Supply Margins of sub-regions of the Western Interconnection. It identifies sub-regions within WECC that have the potential for electricity supply shortages based on reported demand and resource data, assumed non-contracted economic transfers and considering transmission constraints between the sub-regions.

The members of the WECC Loads and Resources Subcommittee (LRS) have the responsibility to establish the tools, methodology, and data requirements for conducting the Power Supply Assessment annually. The responsibility is described in the attached document entitled "WECC Power Supply Assessment Policy" (Attachment 4).

The purpose of this report is to present the results of the Power Supply Assessment that was conducted during the second quarter of 2008. The studies cover the summer period from 2009 through 2017, and the winter period from 2009/10 through 2017/18. The input data represent the Balancing Authority Loads and Resources (L&R) data submitted in December 2007. The SAM model that was developed by the California Energy Commission was used to produce the results for the assessment.

The Pacific Northwest energy assessment (Attachment 7) evaluated the energy limitations of the predominantly hydro system in this specific zone within the Northwest sub-region.

Key Definitions

Class 1 Generation Additions – planned generation additions (projects) that are currently under active construction and projected to be in-service prior to January 2012.

Class 1 Generation Retirements – planned generation retirements or planned long term shutdowns that will take place prior to January 2012.

Class 2 Generation Additions – planned generation additions (projects) that have received all regulatory approvals, with a signed interconnection agreement, and a projected in-service date prior to January 2014.

Class 2 Generation Retirements – planned generation retirements or planned long term shutdowns that will take place prior to January 2014.

Class 3 Generation Additions – planned resource additions (projects) that are at least under regulatory review with a facility study completed, and in active negotiations for an interconnection agreement, with a projected in-service date prior to January 2014.

Class 3 Generation Retirements – planned generation retirements or planned long term shutdowns that will take place prior to January 2014.

Class 4 Generation Additions/Retirements – planned generation additions, retirements or planned long term shutdowns that do not meet the criteria for Class 1, Class 2, or Class 3 but have met the NERC criteria for Planned Resources[10]. Class 4 changes were not included in any of the cases of this assessment.

[10] *NERC Planned Capacity:* This category is for capacity which has achieved one or more of the following milestones: I) Construction has started, II) At least one of the following regulatory permits approved: a) Site permit, b) Construction permit, or c) Environmental permit, III) Corporate management has approved at least one of the following: a) Included in a capital budget or b) BOD approved.

Class 5 Generation Additions/Retirements – planned generation additions, retirements or long term shutdowns that do not meet the criteria for Class 1, Class 2, or Class 3 but have met the NERC criteria for Proposed Resources[11]. Class 5 changes were not included in any of the cases of this assessment.

Existing Generation – generation that was available (in-service) as of December 31, 2007.

Peak Demand – the demand or load that is expected to be served during the peak hour of the month being studied. The peak demand in this assessment is the total demand (firm demand plus non-firm demand as reported by the control areas). Note that in this assessment, demand is synonymous with load.

Power Supply Margin – PSA result identifying the amount of available resource capacity (including net imports) in excess of the demand requirements, after applying the specified adjustments to both demand and resources and accounting for the non-contracted zonal transfers calculated by the model (see discussion below).

Restricted Transfer Capabilities – These are the transfer capabilities that may reasonably be expected to apply under simultaneous high seasonal adverse transmission loading conditions.

Power Supply Margin versus Reserve Margin

It is important to understand the relationship between the output of the SAM model and a reserve margin calculation. In equation form the SAM output, referred to as Power Supply Margin, is

Power Supply Margin = Resource capacity + Imports – Exports – Load Requirement

(where both Resource capacity and Load Requirement include case adjustments)

While this equation is very similar to the equation for calculating a reserve margin, the key difference is that the SAM model also calculates the Imports and Exports simultaneously for all zones during its solution. When the internal resource capacity for a zone is less than the load requirement, SAM will import additional capacity, if available, to meet the load requirement. For example, if the resource capacity for a zone is 1,000 MW and the load requirement is 2,000 MW, SAM will attempt to import 1,000 MW to make up the difference. Assuming that there are no exports, the Power Supply Margin is then (1,000 + 1,000 – 0 – 2,000) = 0 MW and the load requirement is met.

In order to model a reserve margin with SAM, it is necessary to apply the desired or assumed reserve margin as an input parameter prior to running SAM. This is done by increasing the load by the reserve margin factor. Then as long as the Power Supply Margin is not negative, the reserve margin target has been met.

Synopsis of Input Data

The input data consists of the following data collected from the WECC control areas:

a) Generation capacities including planned additions and retirements,
b) Monthly peak demand forecasts,
c) Generation outage forecasts,

[11] *NERC Proposed Capacity:* This category includes generation that is not in a prior listed category, but has been identified through one or more of the following sources: I) Corporate announcement, II) Included in integrated resource plan, III) Generator Interconnection Queues and IV) Interconnection study requested.

d) Zone to zone transfer capabilities, and
e) Load temperature sensitivity data in megawatts per degree Fahrenheit.

The generation capabilities represent the expected seasonal available capacities. The peak demands represent the 1–in–2 probability load forecasts, and include the expected firm and non-firm demand for the peak hour of the study month. It was assumed that the forecast monthly non-coincidental peak demands for each zone will occur at the same time (no diversity). Studies indicate that the simultaneous combined peak demand for WECC is approximately 2% to 4% less than the non-simultaneous demand.

The model does not use, nor does WECC's Loads and Resources data request collect, information about incremental energy efficiency or "customer side of the meter" supply resources that each Balancing Authority might have embedded in the load forecasts and believe are reasonable assumptions for the future.

Building Block Guideline for Reserve Margin

The reserve margins for all of the cases except Case 5 were based on the Building Block Guideline developed by the LRS, and approved by the Planning Coordination Committee (PCC) and the Board of Directors. The Building Block Guidelines/targets are made up of four elements:

1. Contingency Reserves - An additional amount of operating reserve sufficient to reduce area control error (ACE) to zero in 10 minutes following loss of generating capacity, which would result from the most severe single contingency. The contingency calculation was done using resource and load data collected through the 2007 L&R data request. The contingency reserve element for the 2008 PSA was calculated using the proposed Contingency Reserve Standard (CRS). The proposed CRS requires that Balancing Authorities (BA) carry reserves equal to 3% of their load plus 3% of their generation. Because WECC does not track contracted purchases or sales, which will increase or decrease the individual BA's reserve requirement, a reserve requirement of six percent was used for all BA's for the 2008 PSA. The Contingency Reserve used in the 2007 PSA was calculated using the minimum operating reserve criteria (MORC) which required BA's to carry reserves equal to 5% of their load responsibility served by hydro resources and 7% of their load responsibility served by non-hydro resources. The weighted average for contingency reserves for the 2007 PSA was 6.3%. Contingency reserves are required to be carried by Balancing Authorities (individually or through reserve sharing pools) by NERC and WECC standards.

2. Regulating Reserves - The amount of spinning reserves responsive to automatic generation control (AGC), which is sufficient to provide normal regulating margin. The regulating component of the guideline was calculated using responses received in the 2008 PSA data request. Balancing Authorities were asked how much regulating reserve they would expect to carry during 2008, as either a MW value or as a percentage of load. MW responses were converted to a percentage of load by dividing the MW provided by the forecasted 2008 peak demand. A "sanity" check was done to all responses and those that seemed unreasonably low or high were replaced by the weighted average of reported regulating reserves. Regulating reserves are required to be carried by Balancing Authorities by NERC and WECC standards.

3. Additional Forced Outages - Reserves for additional forced outages, beyond what might be covered by operating reserves in order to cover second contingencies, were calculated using the forced outage data supplied to WECC through the L&R data request. Six years of data (2001–2006) were averaged to calculate both a summer (July) and winter (December) forced outage rate. The actual calculation is total forced outages (data code 16) divided by total resources reported in the L & R request (data codes 3 through 13). The same forced outage rate was used for all Balancing Authorities in WECC when calculating the Building Block Guideline. These reserves are not required to be carried by Balancing Authorities by NERC or WECC standards.

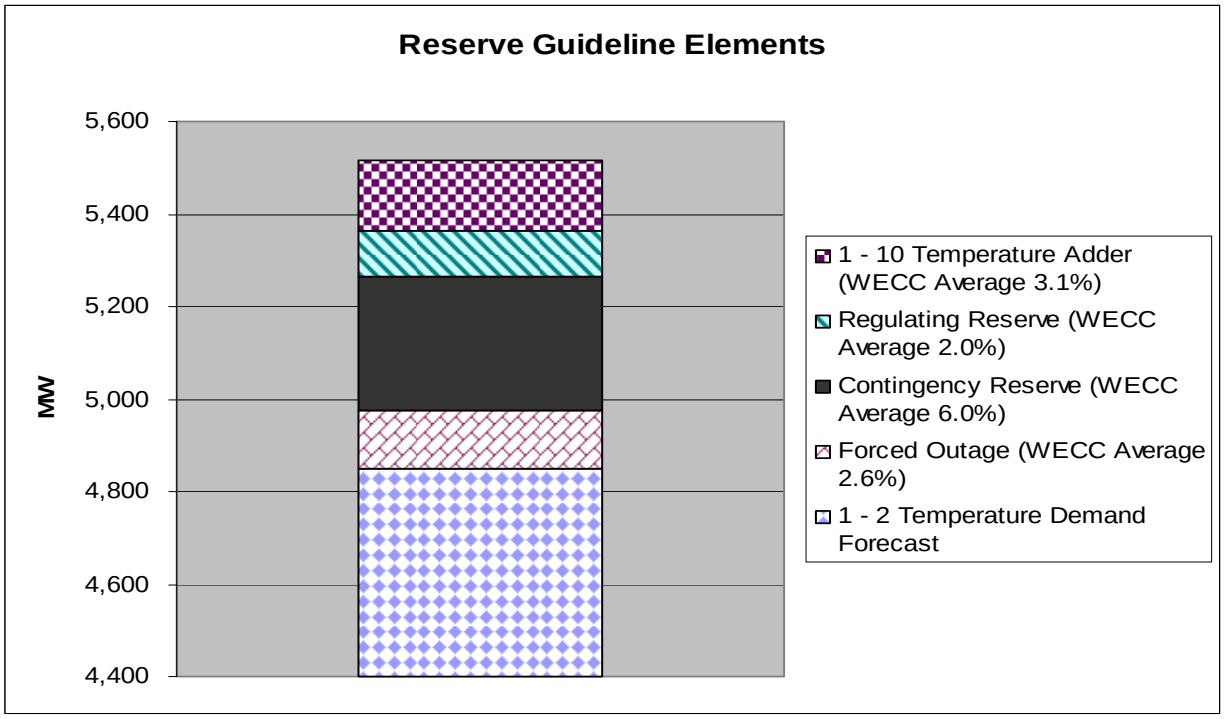
4. Temperature Adders - Using historic temperature data for up to 17 years, the annual maximum and minimum temperature for each Balancing Authority area[12] was identified.

[12] For the CAISO, which covers three SAM zones with significantly varying weather and load responses, the analysis was done by zone, rather than for the ISO as a whole.

That data was used to calculate the average maximum (summer) and minimum (winter) temperature and the associated standard deviation. The standard deviation was multiplied by a 90% probability factor, and added to the average historic temperature to convert from a 1–in–2 temperature (50% exceedence) condition to a 1–in–10 (10% exceedence) condition. The 1–in–2 temperature was subtracted from the 1–in–10 temperature to calculate the temperature change associated with the 1–in–10 outlook. The temperature change was then multiplied by the MW per degree change supplied by the individual Balancing Authorities to arrive at a MW increase associated with converting from a 1–in–2 temperature related forecast to a 1–in–10 forecast. This MW change was divided by the forecast peak demand from 2008 to create a percentage change to be applied to future demand forecasts to convert from a 1–in–2 forecast to a 1–in–10 forecast. An example calculation is given in Attachment 5. These reserves are not required to be carried by Balancing Authorities by NERC or WECC standards.

Graph 4 illustrates the WECC-wide average for the summer building block elements on top of a hypothetical Balancing Authority's basic demand forecast (1–in–2 temperature demand). Note that the vertical scale is truncated to more readily show the size of each building block.

Graph 4 – Elements of the Building Block Planning Reserve Guideline



Tables 5 and 6 show the reserves, in MW, and percent of load by sub-region that were calculated using the building blocks. Note that this calculation produces a constant percentage margin above load over time.

Table 5 - Summer Building Block Reserve Requirements by Sub-Region in MW and Seasonal Percent of Load

Sub-region	2009	2010	2011	2012	2013	2014	2015	2016	2017	Average
Canada	2,082	2,130	2,191	2,247	2,306	2,351	2,408	2,458	2,518	11.3%
Northwest	3,595	3,649	3,696	3,763	3,819	3,877	3,929	3,983	4,035	14.3%
Basin	1,506	1,542	1,575	1,622	1,658	1,690	1,725	1,767	1,793	12.2%
Rockies	1,584	1,608	1,645	1,686	1,729	1,769	1,813	1,862	1,907	11.8%
Desert SW	4,247	4,366	4,495	4,618	4,734	4,861	4,988	5,107	5,234	13.3%
No. CA	4,043	4,101	4,162	4,221	4,280	4,337	4,395	4,451	4,504	14.7%
So. CA/MX	5,558	5,645	5,735	5,824	5,912	6,002	6,091	6,181	6,269	15.7%
Total WECC	22,614	23,042	23,500	23,982	24,439	24,887	25,348	25,810	26,260	13.7%

Table 6 - Winter Building Block Reserve Requirements by Sub-Region in MW and Seasonal Percent of Load

Sub-region	2009	2010	2011	2012	2013	2014	2015	2016	2017	Average
Canada	2,957	3,032	3,116	3,191	3,272	3,333	3,400	3,468	3,548	13.2%
Northwest	4,767	4,821	4,883	4,946	5,005	5,062	5,123	5,180	5,249	15.8%
Basin	1,208	1,237	1,251	1,289	1,312	1,339	1,363	1,391	1,409	11.7%
Rockies	1,554	1,579	1,611	1,652	1,688	1,728	1,767	1,808	1,853	13.4%
Desert SW	2,559	2,627	2,698	2,772	2,838	2,912	2,987	3,057	3,132	12.8%
No. CA	2,135	2,167	2,200	2,233	2,266	2,297	2,328	2,356	2,385	10.5%
So. CA/MX	3,073	3,119	3,168	3,216	3,263	3,311	3,359	3,407	3,454	11.4%
Total WECC	18,253	18,582	18,927	19,299	19,643	19,982	20,327	20,667	21,030	12.9%

It is important to note that the values for reserve margins used in the PSA are NOT the values used by individual LSEs or their regulators or local governing boards to evaluate their individual resource adequacy. Moreover, they are not intended to supplant any of those values. There is at least one sub-region which is a competitive wholesale market for which there is no mandated reserve margin. A more complete description of this issue is given in Attachment 6.

WECC Resource Additions

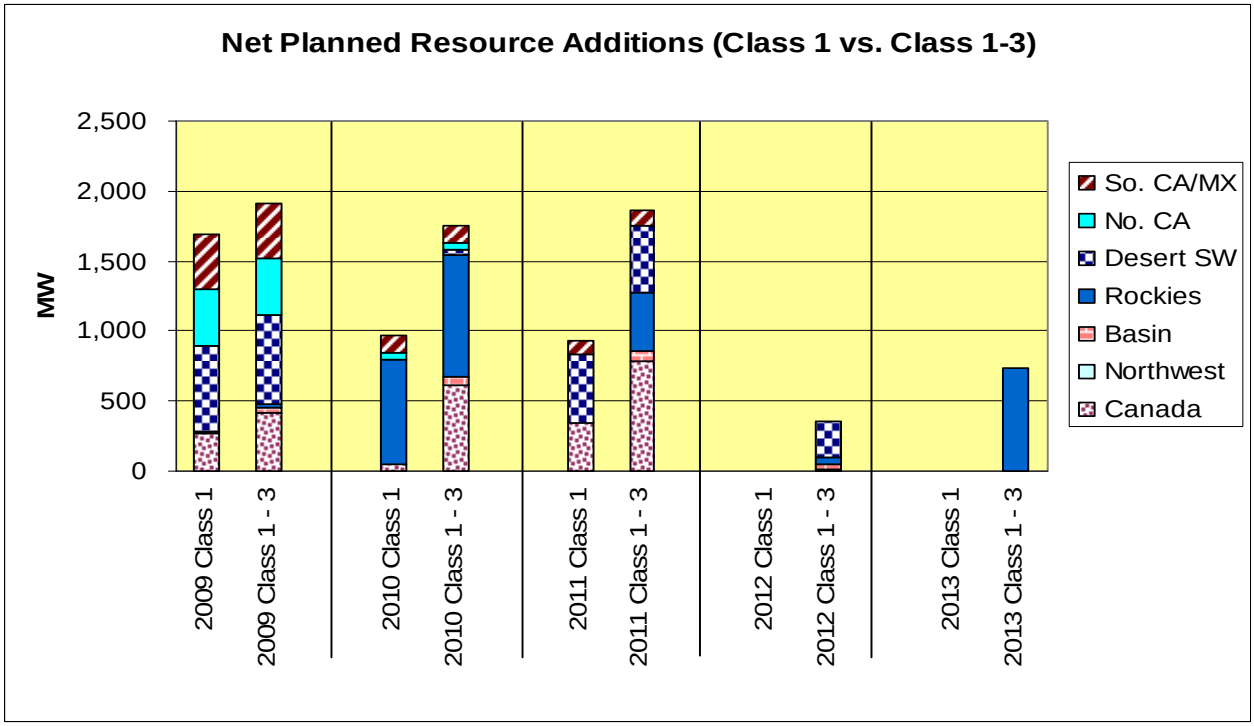
The Load and Resources data submittals included a list of planned generation additions, changes, and retirements. Table 7 is a summary of the WECC reported resource additions by class. The majority of the reported projects are Class 4 and 5 additions (not under active construction nor proposed for regulatory review) and these projects were excluded from any of the analyses in this assessment. A detailed list of the identified generation projects is provided in Attachment 8.

Table 7 – Net Annual Planned Resource Additions by Class (Summer Capacity)

Class	2009	2010	2011	2012	2013	2014	2015	2016	2017	Total
1	1,694	966	931	0	0	0	0	0	0	3,591
2	27	43	473	7	4	0	0	0	0	554
3	196	749	457	350	726	0	0	0	0	2,478
1-3	1,917	1,758	1,861	357	730	0	0	0	0	6,623
4	1,117	1,255	830	718	27	727	775	750	0	6,199
5	1,923	5,100	1,186	1,061	896	255	377	(80)	598	11,316
4-5	3,040	6,355	2,016	1,779	923	982	1,152	670	598	17,515
Total	4,957	8,113	3,877	2,136	1,653	982	1,152	670	598	24,138

Graph 5 compares Class 1 planned resource additions with Class 1 through 3 planned additions. By the definition of Class 1, 2 and 3 resources, no additions beyond 2013 are included in this graph. However, it is logical to expect that more projects will be built as they are needed and as older projects are retired. One of the purposes of this Power Supply Assessment is to apply reasonably uniform criteria in making resource assessments across WECC and its various sub-regions, so that the industry can understand the need for additional resources.

Graph 5 – Net Planned Resource Additions by Year and Sub-Region



Nevertheless, caution needs to be exercised about the resources reported in Class 4 and 5. For example, the new generation additions reported by the AESO was based on projects in the AESO generator interconnection queue which included all projects requesting interconnection to the AESO grid. A significant percentage of the projects in this queue are short lead-time technologies which are responding to market conditions and may not yet be in the regulatory permitting phase. Consequently, exclusion of Class 4 and 5 category generation has a significant impact on the Power Supply Margins in the Canada sub-region.

This non-discriminatory enumeration of all project proposals has previously been a problem for the CAISO, but the CAISO has made efforts to limit its reported additions to a more realistic subset of projects. The CAISO is also pursuing an inter-connection queue reform initiative that will prevent large numbers of highly speculative proposals from interfering with transmission impact assessments for viable projects.

Finally, the existing Loads & Resources data request process systematically excludes resources that have very short lead-times for development, or that are dependent upon associated transmission development. Wind resources can be permitted and built within a year if they can be interconnected without requiring expanded transmission capacity. Such resources will not show up in the data obtained from Balancing Authorities even though they might be very likely additions or be mandated by state RPS laws.

Summary of Assessment Results by Case

The results that are reported in this report are a measure of the ability of the defined sub-regions to meet their load requirements with internal generation and imports from other sub-regions or zones under the specified conditions. The Loads and Resources Subcommittee approved a set of study cases to model the criteria, but recognized that the interpretation and methodology are limited by the modeling tool.

Case Descriptions

The common criteria used in all of the cases included: Existing Generation as of December 31, 2007, Class 1 Generation Additions, Scheduled Maintenance/Inoperable, Adverse Hydro, and Total Demand (firm plus non-firm). The criteria that varied in the study cases are summarized in Table 8. Note that "additions" refers to generation additions and retirements.

Table 8 - Case Criteria Matrix

Criteria	#1	#2	#3	#4	#5
Generation					
Class 2 – 3 Additions (under active regulatory review, or have received regulatory approval, with a completion date prior to January 2014)	No	No	Yes	Yes	No
Peak Demands					
Peak Month	Jul	Dec	Jul	Dec	Jul
Reserve Requirement	Building Block	Building Block	Building Block	Building Block	15%
Temperature Event	No	No	No	No	No

The Class 4–5 resource additions were excluded from all of the cases for this year's assessment. These are projects that were reported but are not currently under active construction or in any regulatory approval process.

Result Aggregation

The assessment results are aggregated into seven defined sub-regions (see Table 9) due to limitations of the modeling and to maintain the confidentiality of years 2 and 3 of load forecast data. The actual zonal topology is presented in the Bubble Diagrams on pages 57 (summer) and 58 (winter). The colors of the zones (described as "bubbles") in the diagrams also identify the grouping of the zones into the aggregate sub-regions.

Table 9 – Sub-Regional Zones and Balancing Authorities

Sub-Region	Zones in Sub-Region	Balancing Authorities in Sub-Region
Canada	Alberta, British Columbia	Alberta Electric System Operator, British ColumbiaTransmission Corporation
Northwest	COB, Montana, Pacific Northwest	Avista Corporation, Bonneville Power Administration, City of Tacoma, Northwestern Energy, Pacificorp, Portland General Electric, Chelan County PUD, Grant County PUD, Douglas County PUD, Puget Sound, Seattle City Light, Western Area Power Administration - Upper Great Plains Region
Basin	Idaho, IPP, No. Nevada, Utah	Idaho Power, Pacificorp, Sierra Pacific Power
Rockies	Colorado - East, Colorado - West, Wyoming	Pacificorp, Public Service of Colorado, Western Area Power Administration - Rocky Mountain Region
Desert Southwest	Arizona, Four Corners, Imperial Irrigation District, New Mexico, Palo Verde, So. Nevada	Arizona Public Service, Dynegy Arlington Valley, El Paso Electric, Gila River Power, Harquahala Generating, Imperial Irrigation District, Nevada Power, Public Service of New Mexico, Salt River Project, Tucson Electric, Western Area Power Administration - Desert Southwest Region
Northern California	Central CA, Northern CA, Sacramento Municipal Utility District, San Francisco	California Independent System Operator, Sacramento Municipal Utility District, Turlock Irrigation District
Southern California/Mexico	Comision Federal de Electricidad, Los Angeles Department of Water and Power, San Diego, Southern CA	California Independent System Operator, Comision Federal de Electricidad, Los Angeles Department of Water and Power

Interpretation of Power Supply Margin Tabulations

The Power Supply Margin Tables display the excess capacity in each sub-region for each year of the study. The sub-region values are the sum of the Power Supply Margins for the zones in each sub-region. **If the Power Supply Margin is zero or positive, then the combination of sub-region resources and sub-region imports is sufficient to meet or exceed the load requirements, including any reserves defined for the given case.**

A positive Power Supply Margin implies that a sub-region has excess generation capacity that is either not needed by other sub-regions, or that there are transmission constraints that prevent the excess capacity from being delivered to other sub-regions that are deficit.

A zero margin is an indication that a sub-region is in load-resource balance or that there are transfers involved. The model will import more capacity then is needed to cover the load requirement if the import is economical, but nonetheless, the load requirement has been met.

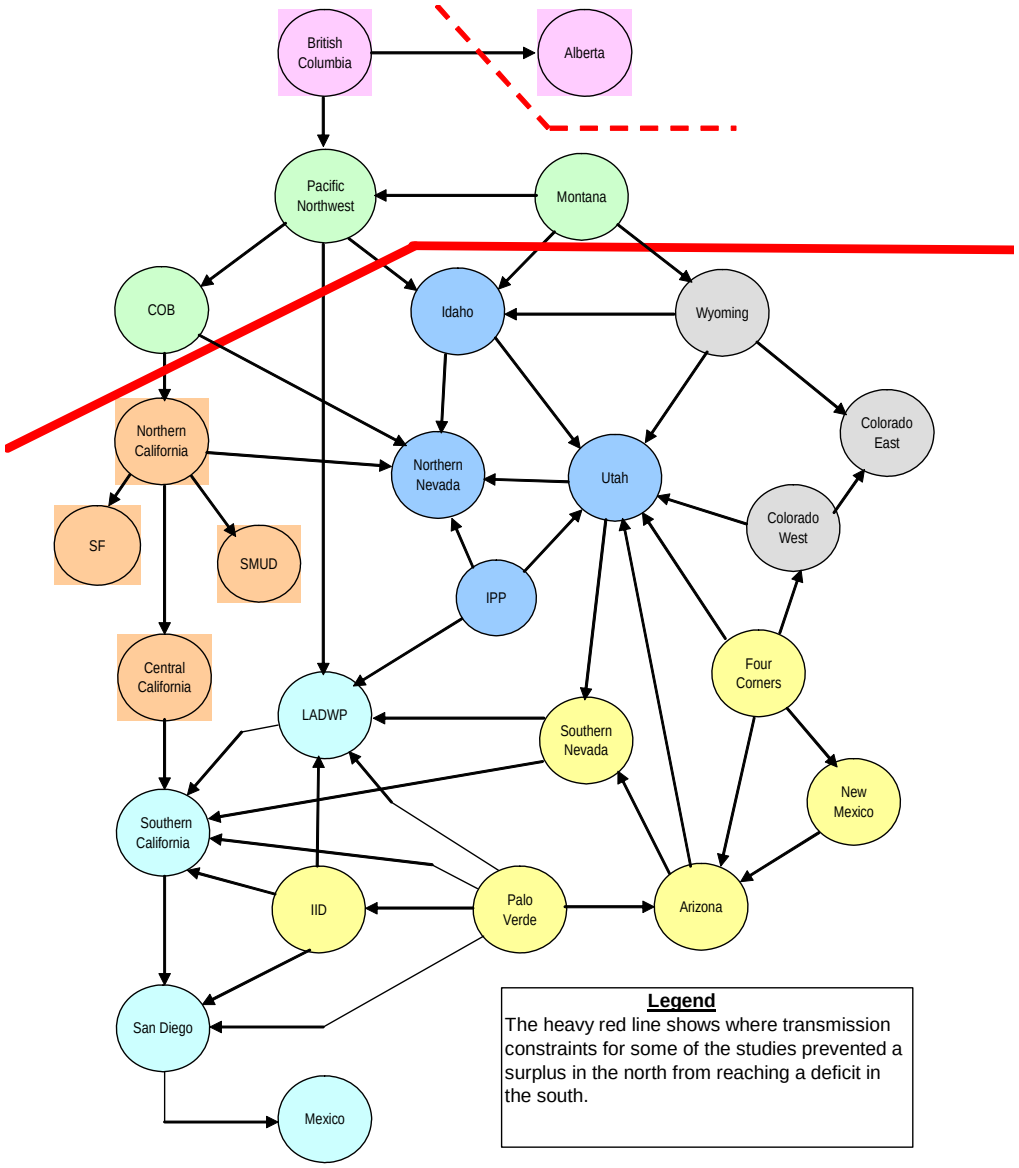
A negative Power Supply Margin indicates that the combination of sub-region resources and sub-region imports were not sufficient to meet the load requirements. If the overall WECC margin is not deficit, one or more transmission constraints between the surplus sub-region(s) and the deficit sub-region(s) must exist. When the total WECC margin becomes negative, additional transmission capacity would not be able to resolve all sub-regional deficits.

A non-negative Power Supply Margin for a sub-region doesn't necessarily mean that the load requirements in all of the sub-region's zones were satisfied. The sub-region Power Supply Margins are the sum of the zonal Power Supply Margins, some of which could be negative.

Result Summaries

Summaries of the results for each case are presented in this section of the report. Additional details are presented in Attachment 3.

A condition called the "North-South split" shows up in this year's and previous PSA analyses. This occurs when the transmission system between the Northwest/British Columbia/Montana (the North[13]) and the areas to the south (the South) is insufficient to allow all reported surpluses north of the constraint to meet loads south of the constraint in the economic dispatch performed in SAM. The diagram below shows the location of this split as it shows up in this year's analysis.



Note, however, that transmission may be constraining on exports from the North to the South in the summer cases following only because the reported surplus in the Northwest is so large. The real size of this surplus may be substantially smaller due to the data issues mentioned earlier in this report, and may even be smaller than the otherwise constraining transmission paths. In any case, it is unlikely that additional summer capacity transfers out of the Northwest, other than what is already calculated in SAM, would be available under poor water conditions. This caveat needs to be taken into account in all the following summer cases.

[13] Alberta does not contribute to the surplus.

In each of the following cases two matrices are presented which summarize the capacity situation of each sub-region. The first matrix displays the Power Supply Margin, in megawatts (MW). The yellow highlighting helps to show the deficits identified in the margin table. The second matrix displays the margin status of the individual zones within the sub-region. This matrix highlights the fact that individual zones within a sub-region may be deficit before the entire sub-region becomes deficit. The first of the annual columns shows the number of surplus zones, the second column shows the number of balanced zones, and the third column shows the number of zones within each sub-region that are deficit.

Case #1 – Summer Modeling Building Block Reserve Guideline

Resource Parameters	
Existing Generation	Included
Class 1 Additions	Included
Class 2 and 3 Additions	Excluded
Outages and De-rates	
Adverse Hydro	Yes
Scheduled Maintenance	Yes

Demand/Load Parameters	
Firm Demand	Included
Non-firm Demand	Included
Reserve Margin	Building Block
Study Month	July
Temperature Event	No
Transfer Capability	Restricted

This case models the Building Block Reserve Margin guideline formulated by the Loads and Resources Subcommittee, as outlined in the Building Block Reserve Margin section of this report. With the appropriate Building Block Guideline applied as a reserve margin requirement to each zone, the Power Supply Margin (see table below) is greater than or equal to zero for all zones through 2009. Beginning in 2010, insufficient resource capacity and transmission in the south, and the effect of a transmission constraint on exports from the Northwest, cause the Desert Southwest and the Southern California/Mexico sub-regions to become deficit. By 2015 all sub-regions except the Northwest sub-region are deficit. The total deficit in the sub-regions in 2010 is approximately 1,120 MW, and the deficit grows by approximately 3,000 MW per year. The deficit is approximately 22,400 MW by 2017.

Power Supply Margin (MW) by Sub-Region for Case #1

Sub-region	2009	2010	2011	2012	2013	2014	2015	2016	2017
Canada	1,348	1,375	1,414	997	533	129	-336	-830	-1,418
Northwest	6,521	5,848	5,111	4,324	3,767	3,292	2,739	2,346	1,957
Basin	0	0	-86	-613	-939	-1,238	-1,550	-1,936	-2,168
Rockies	0	0	-345	-750	-1,166	-1,553	-1,952	-2,410	-2,829
Desert SW	331	-978	-2,169	-3,331	-4,289	-5,330	-6,388	-7,367	-8,407
No. CA	0	0	0	0	-145	-535	-938	-1,318	-1,691
So. CA/MX	0	-138	-842	-1,753	-2,767	-3,539	-4,311	-5,094	-5,866
Surplus	8,201	7,223	6,525	5,321	4,300	3,421	2,739	2,346	1,957
Deficit	0	-1,116	-3,441	-6,446	-9,306	-12,196	-15,475	-18,955	-22,378

Count of Surplus, Balanced, and Deficit Zones in Case #1

Sub-region	2009	2010	2011	2012	2013	2014	2015	2016	2017
Canada	2 : 0 : 0	2 : 0 : 0	2 : 0 : 0	1 : 0 : 1	1 : 0 : 1	1 : 0 : 1	1 : 0 : 1	1 : 0 : 1	1 : 0 : 1
Northwest	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0
Basin	0 : 4 : 0	0 : 4 : 0	0 : 3 : 1	0 : 3 : 1	0 : 3 : 1	0 : 3 : 1	0 : 3 : 1	0 : 3 : 1	0 : 3 : 1
Rockies	0 : 3 : 0	0 : 3 : 0	0 : 2 : 1	0 : 2 : 1	0 : 1 : 2	0 : 1 : 2	0 : 1 : 2	0 : 1 : 2	0 : 1 : 2
Desert SW	2 : 4 : 0	0 : 4 : 2	0 : 3 : 3	0 : 3 : 3	0 : 3 : 3	0 : 3 : 3	0 : 3 : 3	0 : 3 : 3	0 : 3 : 3
No. CA	0 : 4 : 0	0 : 4 : 0	0 : 4 : 0	0 : 4 : 0	0 : 3 : 1	0 : 3 : 1	0 : 3 : 1	0 : 2 : 2	0 : 2 : 2
So. CA/MX	0 : 4 : 0	0 : 2 : 2	0 : 2 : 2	0 : 1 : 3	0 : 1 : 3	0 : 1 : 3	0 : 1 : 3	0 : 1 : 3	0 : 1 : 3

The Count table indicates that in 2010 two zones in the Desert Southwest sub-region and two zones in the Southern California/Mexico sub-region are deficit. By 2012 all sub-regions, except the Northwest, have at least one zone that is deficit. The Count table also indicates that the Canadian sub-region has a deficient zone even when the entire sub-region is not deficit due to a west to east transmission constraint between British Columbia and Alberta.

The data and the model's solution method do not allow a precise determination of which particular zone or zones would actually be deficit. The issue of which zones, or even which sub-regions are deficit is compounded by the absence of surplus capacity in the south and unused transfer capability between the southern sub-regions. The solution arrived at in the SAM calculation is only an estimation of which zones or sub-regions would be impacted first.

Comparison of Effect of Planning Reserves and Operating Reserves

As a sensitivity analysis, the following tables show the Power Supply Margin when comparing a 6% operating reserve with the existing resources and Class 1 additions. This comparison is very informative as it highlights the difference between a planning reserve and an operating reserve, and shows that a planning reserve deficit is not an indication of an operational problem, if normal weather (1–in–2 July peak temperatures) occurs. As would be expected, the onset of a reserve deficit is delayed when resources are compared only to loads plus an operating reserve. All of the sub-regions, with the exception of the Northwest, show changes as to when the first deficit occurs. The Basin, Rockies, Desert Southwest and Southern California/Mexico sub-regions do not indicate a shortage until 2014 which is at least 3 years later than when compared to the Building Block Reserve, and the Northern California sub-region shows no deficit during the study period. The Desert Southwest sub-region perhaps displays the most dramatic change, from a 978 MW deficit to a 6,328 MW surplus, in 2010. This swing was caused by the combination of a reduction in reserves (approximately 2,400 MW) along with an increase in imports (approximately 2,450 MW) and a reduction in exports (approximately 2,500 MW).

Power Supply Margin (MW) by Sub-Region Including Only an Operating Reserve

Sub-region	2009	2010	2011	2012	2013	2014	2015	2016	2017
Canada	1,863	1,513	1,414	1,414	1,138	754	323	-61	-496
Northwest	12,079	11,237	10,009	8,351	7,171	6,239	5,480	5,033	4,552
Basin	0	0	0	0	0	-327	-597	-962	-1,184
Rockies	0	0	0	0	0	-681	-1,067	-1,500	-1,897
Desert SW	7,023	6,328	4,897	2,564	330	-477	-2,089	-3,795	-5,142
No. CA	0	0	0	0	0	0	0	0	0
So. CA/MX	141	94	0	0	0	-411	-660	-917	-1,574
Surplus	21,106	19,172	16,320	9,765	8,310	6,993	5,803	5,033	4,552
Deficit	0	0	0	2,564	330	-1,896	-4,412	-7,234	-10,293

Case #2 – Winter Modeling Building Block Reserve Guideline

Resource Parameters	
Existing Generation	Included
Class 1 Additions	Included
Class 2 and 3 Additions	Excluded
Outages and De-rates	
Adverse Hydro	Yes
Scheduled Maintenance	Yes

Demand/Load Parameters	
Firm Demand	Included
Non-firm Demand	Included
Reserve Margin	Building Block
Study Month	December
Temperature Event	No
Transfer Capability	Restricted

Case #2 models the Building Block Reserve Margin guideline, but under winter conditions. With the applicable Building Block Guideline applied as a reserve margin requirement to each zone, the Power Supply Margin is greater than or equal to zero for all zones, with the exception of Canada, through 2016. In 2009 a transmission constraint between the Northwest and British Columbia, as well as a constraint between British Columbia and Alberta triggered a deficit condition in the Canada sub-region. In 2016 the Southern California/Mexico sub-region also becomes deficit, however, as the Count table indicates, that deficit is restricted to one zone within the sub-region.

Power Supply Margin (MW) by Sub-Region for Case #2

Sub-region	2009	2010	2011	2012	2013	2014	2015	2016	2017
Canada	-301	-1,054	-1,220	-1,673	-2,207	-2,729	-3,303	-3,877	-4,556
Northwest	7,687	6,564	5,904	5,359	4,810	4,335	3,593	2,423	1,723
Basin	0	0	0	0	0	0	0	0	0
Rockies	1,123	1,624	1,326	979	669	328	0	0	0
Desert SW	15,347	15,347	15,298	14,632	13,516	12,164	12,024	11,857	11,833
No. CA	7,627	6,860	5,534	4,644	3,991	3,862	3,830	2,873	2,385
So. CA/MX	2,804	2,827	2,950	2,951	2,951	2,307	1,521	806	-433
Surplus	34,588	33,222	31,011	28,565	25,936	22,996	20,967	17,958	15,942
Deficit	-301	-1,054	-1,220	-1,673	-2,207	-2,729	-3,303	-3,877	-4,989

Count of Surplus, Balanced, and Deficit Zones in Case #2

Sub-region	2009	2010	2011	2012	2013	2014	2015	2016	2017
Canada	0 : 1 : 1	0 : 1 : 1	0 : 1 : 1	0 : 1 : 1	0 : 1 : 1	0 : 1 : 1	0 : 1 : 1	0 : 1 : 1	0 : 1 : 1
Northwest	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0
Basin	0 : 4 : 0	0 : 4 : 0	0 : 4 : 0	0 : 4 : 0	0 : 4 : 0	0 : 4 : 0	0 : 4 : 0	0 : 4 : 0	0 : 4 : 0
Rockies	3 : 0 : 0	3 : 0 : 0	3 : 0 : 0	2 : 1 : 0	2 : 1 : 0	1 : 2 : 0	0 : 3 : 0	0 : 3 : 0	0 : 3 : 0
Desert SW	6 : 0 : 0	6 : 0 : 0	6 : 0 : 0	6 : 0 : 0	4 : 2 : 0	4 : 2 : 0	4 : 2 : 0	3 : 3 : 0	3 : 3 : 0
No. CA	3 : 1 : 0	3 : 1 : 0	3 : 1 : 0	3 : 1 : 0	3 : 1 : 0	2 : 2 : 0	2 : 2 : 0	1 : 3 : 0	1 : 3 : 0
So. CA/MX	3 : 1 : 0	3 : 1 : 0	3 : 1 : 0	3 : 1 : 0	3 : 1 : 0	2 : 1 : 1	2 : 1 : 1	1 : 2 : 1	0 : 3 : 1

The Count table indicates that only one of the two zones in the Canada sub-region became deficit. This is due to a transmission constraint that limits imports from the Northwest into British Columbia as well as a constraint between British Columbia and Alberta. Both Canadian zones have load requirements that exceed their generation capability and the SAM solution method allows British Columbia to have first rights to the imports to serve their increasing load.

The situation with the Southern California/Mexico sub-region is more straightforward. Beginning in 2014 Mexico (CFE) has a load requirement that is higher than the sum of their internal resources and their import capability from Southern California.

Case #3 – Summer Modeling Building Block with Class 2 and 3 Changes

Resource Parameters	
Existing Generation	Included
Class 1 Additions	Included
Class 2 and 3 Additions	Included
Outages and De-rates	
Adverse Hydro	Yes
Scheduled Maintenance	Yes

Demand/Load Parameters	
Firm Demand	Included
Non-firm Demand	Included
Reserve Margin	Building Block
Study Month	July
Temperature Event	No
Transfer Capability	Restricted

Case #3 is the same as Case #1 but includes the Class 2–3 resource additions. The addition of the Class 2–3 resources has no effect on deficit sub-regions except the Basin and Rockies sub-regions. The resource additions to the Basin sub-region delay the deficit for one year from 2011 in Case #1 to 2012 in Case #3. The addition to the Rockies sub-region delays the first deficit by one year until 2012. The addition of additional resources in the Rockies sub-region in 2013 eliminates the deficit that existed in 2012, however, the deficit returns in 2014.

Power Supply Margin (MW) by Sub-Region for Case #3

Sub-region	2009	2010	2011	2012	2013	2014	2015	2016	2017
Canada	1,348	1,460	1,499	1,082	618	214	-238	-641	-1,098
Northwest	6,716	6,083	6,380	5,513	4,910	4,427	3,861	3,379	2,862
Basin	0	0	0	-326	-652	-1,003	-1,338	-1,724	-1,960
Rockies	0	0	0	-245	0	-216	-586	-1,043	-1,462
Desert SW	463	-640	-2,037	-3,031	-3,885	-5,030	-6,088	-7,067	-8,107
No. CA	0	0	0	0	-141	-531	-934	-1,314	-1,682
So. CA/MX	0	-138	-630	-1,632	-2,650	-3,422	-4,194	-4,977	-5,749
Surplus	8,526	7,543	7,879	6,595	5,528	4,641	3,861	3,379	2,862
Deficit	0	-778	-2,666	-5,233	-7,327	-10,202	-13,378	-16,766	-20,057

Count of Surplus, Balanced, and Deficit Zones in Case #3

Sub-region	2009	2010	2011	2012	2013	2014	2015	2016	2017
Canada	2 : 0 : 0	2 : 0 : 0	2 : 0 : 0	1 : 0 : 1	1 : 0 : 1	1 : 0 : 1	1 : 0 : 1	1 : 0 : 1	1 : 0 : 1
Northwest	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0
Basin	0 : 4 : 0	0 : 4 : 0	0 : 4 : 0	0 : 3 : 1	0 : 3 : 1	0 : 3 : 1	0 : 3 : 1	0 : 3 : 1	0 : 3 : 1
Rockies	0 : 3 : 0	0 : 3 : 0	0 : 3 : 0	0 : 2 : 1	0 : 3 : 0	0 : 2 : 1	0 : 2 : 1	0 : 1 : 2	0 : 1 : 2
Desert SW	2 : 4 : 0	0 : 5 : 1	0 : 3 : 3	0 : 3 : 3	0 : 3 : 3	0 : 3 : 3	0 : 3 : 3	0 : 3 : 3	0 : 3 : 3
No. CA	0 : 4 : 0	0 : 4 : 0	0 : 4 : 0	0 : 4 : 0	0 : 3 : 1	0 : 3 : 1	0 : 3 : 1	0 : 2 : 2	0 : 2 : 2
So. CA/MX	0 : 4 : 0	0 : 2 : 2	0 : 2 : 2	0 : 1 : 3	0 : 1 : 3	0 : 1 : 3	0 : 1 : 3	0 : 1 : 3	0 : 1 : 3

Although the Power Supply Margin table does not indicate a deficit in the Canadian sub-region until 2015, the Count table shows that a zone within that sub-region is deficit as early as 2012. This deficit is caused by transmission constraints within the sub-region that is preventing transfers from a zone with surplus capacity to a zone that is deficit.

Case #4 – Winter Modeling Building Block with Class 2 and 3 Changes

Resource Parameters	
Existing Generation	Included
Class 1 Additions	Included
Class 2 and 3 Additions	Included
Outages and De-rates	
Adverse Hydro	Yes
Scheduled Maintenance	Yes

Demand/Load Parameters	
Firm Demand	Included
Non-firm Demand	Included
Reserve Margin	Building Block
Study Month	December
Temperature Event	No
Transfer Capability	Restricted

Case #4 is the same as Case #2 but includes the Class 2–3 resource additions. The addition of Class 2–3 has no effect on the timing of when the sub-regions go deficit. The Canada sub-region continues to be deficit throughout the study period. However, the addition of the Class 2–3 resources does reduce the deficit in the Southern California/Mexico sub-region by about 100 MW.

Power Supply Margin (MW) by Sub-Region for Case #4

Sub-region	2009	2010	2011	2012	2013	2014	2015	2016	2017
Canada	-301	-1,054	-1,220	-1,673	-2,191	-2,655	-3,089	-3,540	-4,041
Northwest	7,972	7,375	7,160	6,615	6,050	5,612	4,883	3,943	3,080
Basin	0	0	22	0	0	0	0	0	0
Rockies	1,159	1,782	1,895	1,428	1,634	1,064	990	990	604
Desert SW	15,347	15,387	15,338	14,956	14,060	12,856	12,293	11,897	11,873
No. CA	7,778	7,155	5,888	4,918	4,267	3,862	3,830	2,873	2,827
So. CA/MX	2,804	2,827	2,950	2,951	2,951	2,579	1,794	949	-325
Surplus	35,060	34,526	33,253	30,869	28,961	25,974	23,789	20,652	18,383
Deficit	-301	-1,054	-1,220	-1,673	-2,191	-2,655	-3,089	-3,540	-4,366

Count of Surplus, Balanced, and Deficit zones in Case #4

Sub-region	2009	2010	2011	2012	2013	2014	2015	2016	2017
Canada	0 : 1 : 1	0 : 1 : 1	0 : 1 : 1	0 : 1 : 1	0 : 1 : 1	0 : 1 : 1	0 : 1 : 1	0 : 1 : 1	0 : 1 : 1
Northwest	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0
Basin	0 : 4 : 0	0 : 4 : 0	1 : 3 : 0	0 : 4 : 0	0 : 4 : 0	0 : 4 : 0	0 : 4 : 0	0 : 4 : 0	0 : 4 : 0
Rockies	3 : 0 : 0	3 : 0 : 0	3 : 0 : 0	3 : 0 : 0	3 : 0 : 0	3 : 0 : 0	2 : 1 : 0	2 : 1 : 0	1 : 2 : 0
Desert SW	6 : 0 : 0	6 : 0 : 0	6 : 0 : 0	6 : 0 : 0	5 : 1 : 0	4 : 2 : 0	4 : 2 : 0	3 : 3 : 0	3 : 3 : 0
No. CA	3 : 1 : 0	3 : 1 : 0	3 : 1 : 0	3 : 1 : 0	3 : 1 : 0	2 : 2 : 0	2 : 2 : 0	1 : 3 : 0	1 : 3 : 0
So. CA/MX	3 : 1 : 0	3 : 1 : 0	3 : 1 : 0	3 : 1 : 0	3 : 1 : 0	2 : 1 : 1	2 : 1 : 1	1 : 2 : 1	1 : 2 : 1

The Count table indicates that although the addition of the Class 2 and 3 resources does not affect the timing of supply deficits in the sub-regions, they do affect the deficits within the zones. For example, with the Class 2 and Class 3 additions, zones within the Rockies sub-region indicate supply surpluses when in case #2 the zones were balanced. The Class 2 and Class 3 additions in the Southern California/Mexico sub-region do not have any effect on the deficient zone within that sub-region as the Mexico (CFE) zone still has a load requirement that is higher than the sum of its internal resources and its import capability from Southern California.

Case #5 – Summer Modeling with 15% Demand Escalation

Resource Parameters	
Existing Generation	Included
Class 1 Additions	Included
Class 2 and 3 Additions	Excluded
Outages and De-rates	
Adverse Hydro	Yes
Scheduled Maintenance	Yes

Demand/Load Parameters	
Firm Demand	Included
Non-firm Demand	Included
Reserve Margin	15%
Study Month	July
Temperature Event	No
Transfer Capability	Restricted

Case #5 models an assumed 15% planning reserve margin for each zone. It has no relationship to the Building Block calculation but was included to provide a partial benchmark comparison to the results of previous PSA results for this case. 15% is a planning margin used by some control areas in WECC and is the default margin[14] in the complex Resource Adequacy requirements for most of California. With the demand forecasts for each zone escalated by 15%, the Power Supply Margin is deficit for the Rockies and Desert Southwest sub-regions beginning in 2009, and all sub-regions, with the exception of the Northwest, are deficit by 2013.

Power Supply Margin (MW) by Sub-Region for Case #5

Sub-region	2009	2010	2011	2012	2013	2014	2015	2016	2017
Canada	1,348	1,372	1,117	517	-88	-550	-1,123	-1,633	-2,242
Northwest	5,663	4,974	4,509	3,881	3,440	3,003	2,536	2,140	1,749
Basin	0	-133	-446	-961	-1,318	-1,627	-1,940	-2,251	-2,491
Rockies	-639	-399	-790	-1,211	-1,640	-2,038	-2,449	-2,920	-3,351
Desert SW	-244	-1,697	-2,734	-3,913	-4,884	-5,941	-7,015	-8,009	-9,065
No. CA	0	0	0	0	-234	-627	-1,037	-1,505	-1,878
So. CA/MX	0	-124	-745	-1,678	-2,581	-3,352	-4,126	-4,907	-5,677
Surplus	7,011	5,814	5,626	4,398	3,440	3,003	2,536	2,140	1,749
Deficit	-883	-1,821	-4,715	-7,763	-10,744	-14,134	-17,689	-21,226	-24,704

Count of Surplus, Balanced, and Deficit zones in Case #5

Sub-region	2009	2010	2011	2012	2013	2014	2015	2016	2017
Canada	2 : 0 : 0	2 : 0 : 0	1 : 0 : 1	1 : 0 : 1	1 : 0 : 1	1 : 0 : 1	1 : 0 : 1	1 : 0 : 1	1 : 0 : 1
Northwest	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0
Basin	0 : 4 : 0	0 : 3 : 1	0 : 3 : 1	0 : 3 : 1	0 : 3 : 1	0 : 3 : 1	0 : 3 : 1	0 : 2 : 2	0 : 2 : 2
Rockies	0 : 1 : 2	0 : 2 : 1	0 : 1 : 2	0 : 1 : 2	0 : 1 : 2	0 : 1 : 2	0 : 1 : 2	0 : 1 : 2	0 : 1 : 2
Desert SW	0 : 4 : 2	0 : 3 : 3	0 : 3 : 3	0 : 3 : 3	0 : 3 : 3	0 : 3 : 3	0 : 3 : 3	0 : 3 : 3	0 : 3 : 3
No. CA	0 : 4 : 0	0 : 4 : 0	0 : 4 : 0	0 : 4 : 0	0 : 3 : 1	0 : 3 : 1	0 : 3 : 1	0 : 2 : 2	0 : 2 : 2
So. CA/MX	0 : 4 : 0	0 : 3 : 1	0 : 2 : 2	0 : 1 : 3	0 : 1 : 3	0 : 1 : 3	0 : 1 : 3	0 : 1 : 3	0 : 1 : 3

Here again, the Count table indicates that the Canada sub-region has a deficient zone even when the entire sub-region is not deficit due to a west to east constraint between British Columbia and Alberta.

[14] The California Public Utilities Commission adopted a PRM range of 15-17% in D.04-01-050. In practice, LSEs are held to 15% margin over monthly peak loads. The upper part of the range serves to allow IOUs to acquire "lumpy" resources that would temporarily push the reserve level above 15%.

Comparison of Summer 15% Margin Case to 2007 PSA Results

The following section compares the results of the 15% margin case study from the 2007 PSA with the equivalent case study from the 2008 PSA. The 15% case study allows for a year on year comparison because the classes of resources and the flat 15% margin adder are the same in both studies (except that Class 1 includes one additional year of resources in the 2008 study compared to than in the 2007 study).

2007 PSA 15% Reserve Results

Sub-region	2008	2009	2010	2011	2012	2013	2014	2015	2016
Canada	1,965	1,790	1,458	1,177	890	436	43	-284	-777
Northwest	8,406	7,064	6,747	6,301	5,882	5,423	5,050	4,649	4,185
Basin	0	0	-73	-507	-820	-1,210	-1,544	-1,864	-2,142
Rockies	0	-313	-172	-255	-605	-956	-1,348	-1,765	-2,160
Desert SW	0	-626	-1,366	-2,618	-3,733	-4,707	-5,764	-6,832	-7,799
No. CA	0	0	0	-111	-601	-1,098	-1,573	-2,152	-2,693
So. CA/MX	0	-438	-1,069	-1,948	-2,722	-3,514	-4,329	-5,204	-6,233
Surplus	10,371	8,855	8,205	7,478	6,772	5,859	5,092	4,649	4,185
Deficit	0	-1,377	-2,680	-5,439	-8,481	-11,485	-14,559	-18,101	-21,803

Sub-region	2008	2009	2010	2011	2012	2013	2014	2015	2016
Canada	2 : 0 : 0	2 : 0 : 0	2 : 0 : 0	1 : 0 : 1	1 : 0 : 1	1 : 0 : 1	1 : 0 : 1	1 : 0 : 1	1 : 0 : 1
Northwest	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0
Basin	0 : 4 : 0	0 : 4 : 0	0 : 3 : 1	0 : 3 : 1	0 : 3 : 1	0 : 3 : 1	0 : 3 : 1	0 : 2 : 2	0 : 2 : 2
Rockies	0 : 3 : 0	0 : 2 : 1	0 : 2 : 1	0 : 2 : 1	0 : 2 : 1	0 : 1 : 2	0 : 1 : 2	0 : 1 : 2	0 : 1 : 2
Desert SW	0 : 6 : 0	0 : 4 : 2	0 : 3 : 3	0 : 3 : 3	0 : 3 : 3	0 : 3 : 3	0 : 3 : 3	0 : 3 : 3	0 : 3 : 3
No. CA	0 : 4 : 0	0 : 4 : 0	0 : 4 : 0	0 : 3 : 1	0 : 3 : 1	0 : 2 : 2	0 : 2 : 2	0 : 2 : 2	0 : 2 : 2
So. CA/MX	0 : 4 : 0	1 : 2 : 1	1 : 2 : 1	0 : 1 : 3	0 : 1 : 3	0 : 1 : 3	0 : 1 : 3	0 : 1 : 3	0 : 1 : 3

2008 PSA 15% Reserve Results

Sub-region	2009	2010	2011	2012	2013	2014	2015	2016	2017
Canada	1,348	1,372	1,117	517	-88	-550	-1,123	-1,633	-2,242
Northwest	5,663	4,974	4,509	3,881	3,440	3,003	2,536	2,140	1,749
Basin	0	-133	-446	-961	-1,318	-1,627	-1,940	-2,251	-2,491
Rockies	-639	-399	-790	-1,211	-1,640	-2,038	-2,449	-2,920	-3,351
Desert SW	-244	-1,697	-2,734	-3,913	-4,884	-5,941	-7,015	-8,009	-9,065
No. CA	0	0	0	0	-234	-627	-1,037	-1,505	-1,878
So. CA/MX	0	-124	-745	-1,678	-2,581	-3,352	-4,126	-4,907	-5,677
Surplus	7,011	5,814	5,626	4,398	3,440	3,003	2,536	2,140	1,749
Deficit	-883	-1,821	-4,715	-7,763	-10,744	-14,134	-17,689	-21,226	-24,704

Sub-region	2009	2010	2011	2012	2013	2014	2015	2016	2017
Canada	2 : 0 : 0	2 : 0 : 0	1 : 0 : 1	1 : 0 : 1	1 : 0 : 1	1 : 0 : 1	1 : 0 : 1	1 : 0 : 1	1 : 0 : 1
Northwest	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0	1 : 2 : 0
Basin	0 : 4 : 0	0 : 3 : 1	0 : 3 : 1	0 : 3 : 1	0 : 3 : 1	0 : 3 : 1	0 : 3 : 1	0 : 2 : 2	0 : 2 : 2
Rockies	0 : 1 : 2	0 : 2 : 1	0 : 1 : 2	0 : 1 : 2	0 : 1 : 2	0 : 1 : 2	0 : 1 : 2	0 : 1 : 2	0 : 1 : 2
Desert SW	0 : 4 : 2	0 : 3 : 3	0 : 3 : 3	0 : 3 : 3	0 : 3 : 3	0 : 3 : 3	0 : 3 : 3	0 : 3 : 3	0 : 3 : 3
No. CA	0 : 4 : 0	0 : 4 : 0	0 : 4 : 0	0 : 4 : 0	0 : 3 : 1	0 : 3 : 1	0 : 3 : 1	0 : 2 : 2	0 : 2 : 2
So. CA/MX	0 : 4 : 0	0 : 3 : 1	0 : 2 : 2	0 : 1 : 3	0 : 1 : 3	0 : 1 : 3	0 : 1 : 3	0 : 1 : 3	0 : 1 : 3

As the above charts show, although the magnitude of the surplus' and deficits changed from the 2007 study to the 2008 study, the sub-regions supply deficit happen at approximately the same time. The exceptions are in Canada, which did not show a deficit for the entire sub-region until 2015 in the 2007 PSA, but has the entire sub-region going deficit in 2013 in the 2008 PSA, and California which shows a delay in the first deficit of one year in Southern California, and a delay of two years in Northern California. The Canadian change was caused by an increased demand forecast for 2013 of 3.9%, but with an increase of available resources of only 1.5%. The delayed deficits in California are due to a 1% lower demand forecast for 2009 in the 2008 PSA.

Temperature Events – Cases 6 Through 11

The impacts of severe summer and winter temperature events were examined in Cases 6–11. These cases, unlike Cases 1–5, looked only at a single season, summer 2011 or winter 2011–12. Because they were testing the impact of severe unexpectedly high or low temperatures, they were tested only against the reserve margin that would minimally be maintained in actual operating circumstances. This margin includes the first two building blocks, for Contingencies and for Regulation, and excludes the components for Additional Forced Outages and for 1–in–10 Weather events. Thus, these additional assessments are not directly comparable to the five cases.

The WECC Balancing Authorities were asked to report their load sensitivity to temperature (MW per degree Fahrenheit) for both summer and winter, the temperatures upon which their reported 1–in–2 demand forecasts were based and their temperature extremes. Historical temperature data for Western load centers was developed for the period 1990 to 2004 by a consultant at Lawrence Berkeley National Laboratory (LBL). Historic temperature data for the period of 2005–2007 was requested in the 2008 PSA data request. A statistical process was used to convert the 1–in–2 year weather demand supplied in the 2007 LRS Data Request to a 1–in–10 year weather demand condition. An example of the calculation is given in Attachment 5.

Temperature sensitivity cases were created to examine the impacts of the temperature pattern experienced on July 24th, 2006, as well as several other possible extreme weather patterns. The July 24th analysis was accomplished by comparing the actual demand of July 24th to the forecasted peak demand of July, 2006. This percentage increase was applied to the demand forecasted for July, 2011, and compared to the resources anticipated to be available at that time.

Table 10 – Temperature Sensitivity Description

Temperature Sensitivities: Modified Building Blocks - 2011 only			
Case	**Season**	**New Resources**	**Temperature Definition**
6	Summer	Class 1	July 24, 2006 temperature, 2011 demand
7	Summer	Classes 1-3	July 24, 2006 temperature, 2011 demand
8	Summer	Class 1	Calif., Ariz., S. Nev.: 1-in-20 Rest of West: 1-in-10
9	Summer	Classes 1-3	Calif., Ariz., S. Nev.: 1-in-20 Rest of West: 1-in-10
10	Winter	Class 1	Canada, NW, Basin, N. Calif.: 1-in-20 Rest of West: 1-in-10
11	Winter	Classes 1-3	Canada, NW, Basin, N. Calif.: 1-in-20 Rest of West: 1-in-10

Two cases focused on the temperature event of July 24, 2006 applied to the future year loads. The other four cases focused on more localized and more likely weather stresses, two for the summer and two for the winter. The cases are summarized in Table 10.

In each of the temperature sensitivity cases a study of MW change per degree was done to determine the increase in demand associated with increasing the temperature from a 1–in–2 condition to a 1–in–10 or 1–in–20 temperature condition, depending on the case study[15]. The increase in demand associated with each of the temperature sensitivity cases are shown in Table 11.

Table 11 - Load Requirement Increase (MW) for Temperature Sensitivity Cases

Sub-Region	Case					
	July 24, 2006 temperature, 2011 demand Class 1	July 24, 2006 temperature, 2011 demand Class 1 - 3	Summer Calif., Ariz., S. Nev.: 1-in-20 Class 1	Summer Calif., Ariz., S. Nev.: 1-in-20 Class 1 - 3	Winter Canada, NW, Basin, N. Calif.: 1-in-20 Class 1	Winter Canada, NW, Basin, N. Calif.: 1-in-20 Class 1 - 3
	6	7	8	9	10	11
Canada	785	785	231	231	1,106	1,106
Northwest	3,902	3,902	812	812	2,116	2,116
Basin	415	415	347	347	311	311
Rockies	-380	-380	230	230	391	391
Desert Southwest	1,756	1,756	1,467	1,467	569	569
No. California	4,395	4,395	2,190	2,190	306	306
So. California/Mexico	5,861	5,861	3,407	3,407	288	288

Table 12 contains the resource surplus or deficit under the winter or summer extreme peak conditions of year 2011 for each of the temperature sensitivity cases. It is important to note that these results can not be directly compared to the results from cases 1–5 due to the differences in the reserve components: Contingency and Regulation in Cases 6–11, and all of the Building Block elements in Cases 1–5. However, the column titled "Summer 2011 6% Reserve Margin" is included in Table 12 to facilitate understanding. It shows what the surplus/deficit results would have been in Case 1 (normal loads), if it had only had a margin of 6%.

Table 12 - Resource Surplus/Deficit (MW)

Sub-Region	Summer 2011 6% Reserve Margin	Case					
		July 24, 2006 temperature, 2011 demand Class 1	July 24, 2006 temperature, 2011 demand Class 1 - 3	Summer Calif., Ariz., S. Nev.: 1-in-20 Class 1	Summer Calif., Ariz., S. Nev.: 1-in-20 Class 1 - 3	Winter Canada, NW, Basin, N. Calif.: 1-in-20 Class 1	Winter Canada, NW, Basin, N. Calif.: 1-in-20 Class 1 - 3
		6	7	8	9	10	11
Canada	1,414	1,414	1,499	1,414	1,552	-1,065	-507
Northwest	10,009	2,642	4,005	6,282	7,738	6,328	7,010
Basin	0	0	0	0	0	0	313
Rockies	0	0	0	0	0	1,610	2,179
Desert Southwest	4,897	-1,389	-1,040	-1,458	-1,149	15,311	15,906
No. California	0	-1,194	-1,190	0	0	7,339	6,513
So. California/Mexico	0	-4,120	-3,802	-855	-604	2,950	3,238
Surplus	16,320	4,056	5,504	7,696	9,290	33,537	35,159
Deficit	0	-6,702	-6,032	-2,313	-1,753	-1,065	-507

[15] The Load Requirement Increase for Table 11 of the 2007 PSA was reported to be the increase from a 1-in-2 temperature condition to a 1-in-20 condition. That reference was incorrect. The increases reported in cases 8 through 11 were increases from the 1-in-10 demand to 1-in-20 demand. Depending on the temperature case being studied, some sub-regions did not show a demand increase because the demand had already been adjusted from a 1-in-2 temperature condition to a 1-in-10 condition.

Phase-Out of Once-Through Cooling in California

The California State Water Resources Control Board (SWRCB) has proposed a policy implementing Section 316(b) of the Clean Water Act that would substantially limit the impacts of power plant cooling water intakes on marine environments. The effect of the proposed performance standards would be to eliminate once-through cooling (OTC) and require closed-cycle recirculating cooling systems (or the equivalent) for coastal power plants. The CAISO has estimated in an initial report on this issue that the maximum exposure to plant closing from this policy would be 21,072 MW[16]. The current proposal is for compliance by low capacity factor units by 2015, by 2018 for high capacity factor units and by 2021 for base load nuclear units.

The SWRCB has issued a consultant's report[17] on the grid reliability impacts of the proposal as well, which is part of its process to get to a final proposed policy, expected to be adopted in the spring of 2009. The CAISO Phase 2 report is expected by the end of 2008 with a recommended preferred solution to the problem in a Phase 3 report by the end of 2009.

The issue is currently under substantial discussion among California policy entities and stakeholders. Key issues to be worked through are the implementation schedule and coordination process, the response of the generator owners to the final schedule and cost of compliance for their particular units, and the identification and integration of potential transmission solutions. While the CAISO is working to identify cost effective transmission options, power plant owners have indicated that investing substantial funds to moderate OTC usage does not make sense for power plants that on average are 45 years old. Rather, they would repower their facility if long-term contracts from load serving entities could justify the investment risk. An additional element is the interaction of this replacement of a major portion of California's power plants with renewable generation, which could require a large change to the transmission system to reduce the reliance on these plants to meet local reliability requirements. This is an issue that will need to be followed more closely in future Power Supply Assessments, when the outcomes of the various decisions are clearer.

Because California is a net importer of power during the summer load peaks, the bulk of the impact will be felt in California, though depending on the outcomes, including replacement generation and transmission development, there may be some operating issues raised for transmission operators outside of California that will need to be addressed.

The Northwest, which can, under some circumstances, rely on imports from California and the Southwest in the winter, may be impacted as well, though this too will be highly dependent on the unfolding of the decisions and responses within California.

[16] CAISO "Old Thermal Generation Phase I Report" 29 February 2008 (http://www.caiso.com/1f80/1f80a4a5568f0.pdf). The exposure due to an additional 1,276 MW of generation that does not use once through cooling but was over 30 years old, was also studied in this report.
[17] http://www.waterboards.ca.gov/water_issues/programs/tmdl/docs/power_plant_cooling/reliability_study.pdf

Near-Term Drought Considerations in California

California is currently in the second year of a drought that is forecast to continue. Figure 1 is a drought severity index that shows that the majority of California is currently experiencing an extreme drought. Figure 2 categorizes the drought tendency through December 2008 for Northern California as "Drought ongoing, some improvement" and "Drought to persist or intensify" for Southern California[18].

According to the California Department of Water Resources "An eight-year drought in the Southwest means California can't depend on Colorado River water to help supply Southern California[19]". This has the potential to limit California imports from Hoover as well as other energy imports from the Southwest.

The impact of a continuation of drought conditions on hydroelectric supplies for the 2009 California summer peak period is currently being studied by the CAISO and undoubtedly others. To date, the CAISO has experienced decreases in capacity from the hydro resources committed to resource adequacy, and to a greater extent, energy production. If the drought continues, further reductions of capacity and energy are expected, the extent of which depends on the severity of the drought. To the extent this impacts CAISO system and local reliability, the CAISO intends to develop plans for system enhancements to address possible risks.

Figure 1 - Drought Severity Index

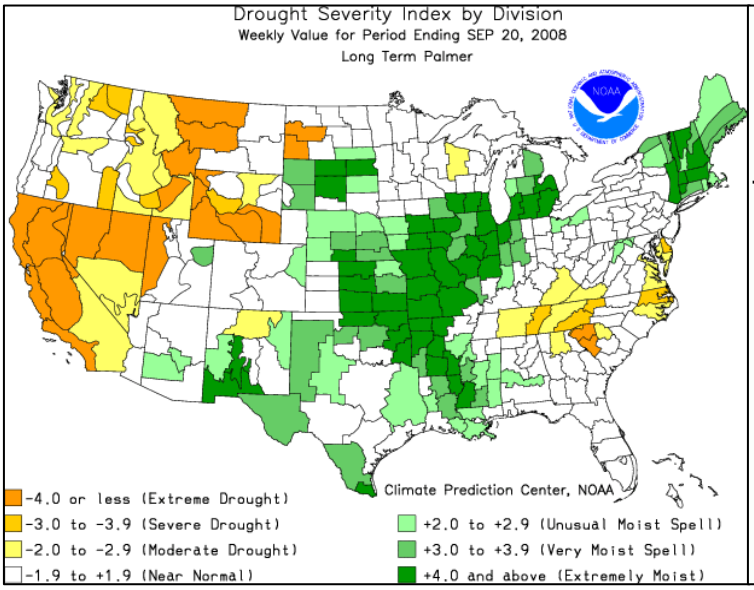
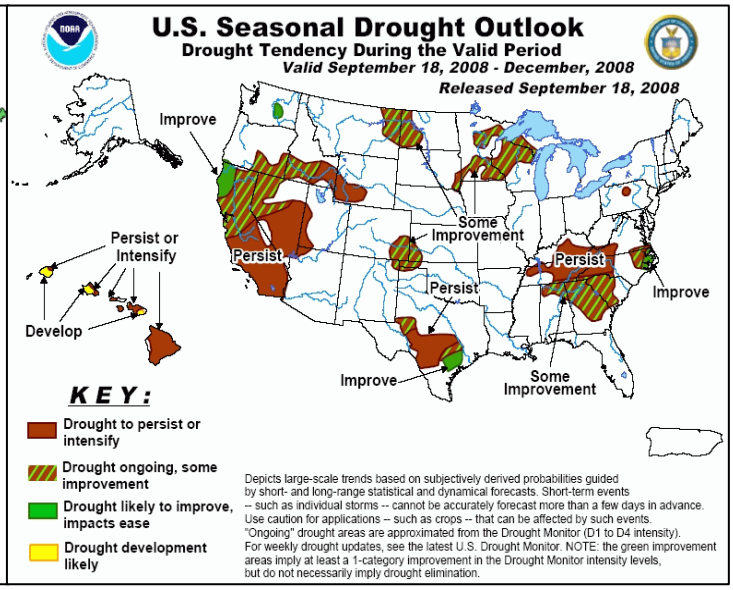


Figure 2 - Seasonal Drought Outlook



[18] National Weather Service Climate Prediction Center
http://www.cpc.ncep.noaa.gov/products/expert_assessment/drought_assessment.shtml
[19] California Department of Water Resources "California drought 2008 Fact Sheet"
http://www.water.ca.gov/drought/docs/drought_FactSheet.pdf

Summary of Assessment Results by Sub-Region

The following section of the PSA presents sub-regional specific graphs and charts. Each graph presents the sub-region's Power Supply Margin through 2017 using three different sets of assumptions. A description of each case is summarized below. Following each graph are three charts listing the Planned Resources Identified by Class, the Planned Resources Identified by Type (Class 1–3 only), and the Planned Resources Indentified by Type (Class 4–5 only). The information represents the winter rating for the Canada and the Northwest sub-regions, and the summer rating for the Basin, the Rockies, the Desert Southwest, and the California sub-regions. Also, the winter (Canada and Northwest) and summer (Basin, Rockies, Desert Southwest, and California) ratings are the reported capacities that are planned to be added during the calendar years for each sub-region. This information is presented to highlight the importance of adding additional resources above and beyond those resources reported in Classes 1–3.

To the extent that the sub-regions are successful in adding Class 4 and 5 resources and/or transmission, the Power Supply Margin pictures may improve as described in the narrative for each sub-region.

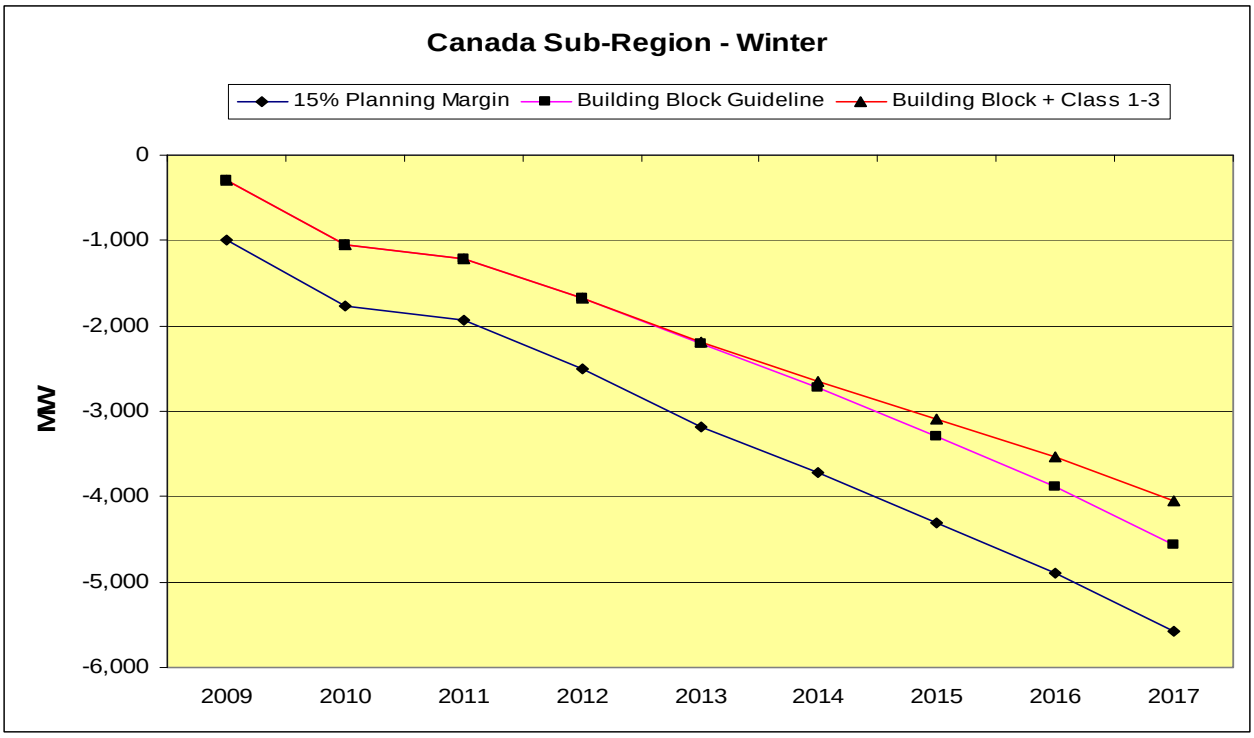
In each of the Graphs 6 – 12, the following nomenclature is used.

Plot Label	Case	Reserve Requirement	Resource Additions
Building Block Guideline	1 – Summer 2 – Winter	Building Block Reserve Guideline	Class 1 only
Building Block + Class 2 & 3	3 – Summer 4 – Winter	Building Block Reserve Guideline	Class 1 – 3
15% Planning Margin	5 – Summer	15% Reserve Margin	Class 1 only

Canada

Sub-Region	Zones in Sub-Region
Canada	Alberta, British Columbia

Graph 6 - Comparison of Canada Sub-Region Power Supply Margin (MW)



The results for the winter case show that the Canada sub-region is currently in need of addition resources or additional import capability.

As depicted in the table, even with the addition of the Class 2 and Class 3 resources the sub-region is in need of additional resources and/or import capability. The AESO reported many proposed resource additions based on projects in the generator interconnection queue. These resources included all projects requesting interconnection to the AESO grid. A significant percentage of the projects in this queue are short lead-time technologies which are responding to market conditions and may not yet be in the regulatory permitting phase. Consequently, exclusion of Class 4 and 5 category generation has a significant impact on the reserve margins in the Canada sub-region. The AESO calculates a Two-Year Probability of Supply Adequacy Shortfall Metric which is a probabilistic assessment of encountering a supply shortfall over the next two years. The calculation estimates, on a probabilistic basis, how much load may go without supply over the next two-year period. Based on extensive consultation with stakeholders, when this unserved energy exceeds 1,600 MWh in any two year period (equivalent to one hour 800 MW shortfall in each of the two years), the AESO may take certain actions to bridge the temporary supply adequacy gap without impacting investor confidence in the market.

On February 27, 2007 British Columbia announced the BC Energy Plan[20] which indicates that at least 90% of all electricity generated in the province must continue to come from clean or renewable sources and to achieve electricity self-sufficiency by 2016. Working towards that goal, BC Hydro & Power Authority is in the process of acquiring 5,000 GWh per year of seasonal and hourly firm "clean" energy through a competitive process. These projects are currently at the RFP stage.

Canada Planned Resources (Winter Rating) Identified by Class (as of Dec. 31)

Sub-region	Class	2009	2010	2011	2012	2013	2014	2015	2016	2017	Total
Canada	1	132	28	344	0	0	0	0	0	0	504
Canada	2	0	0	435	0	0	0	0	0	0	435
Canada	3	121	560	0	0	0	0	0	0	0	681
Total	1-3	253	588	779	0	0	0	0	0	0	1,620
Canada	4	53	1,200	0	0	0	0	0	0	0	1,253
Canada	5	1,010	2,005	0	0	0	0	0	0	0	3,015
Total	4-5	1,063	3,205	0	0	0	0	0	0	0	4,268

Canada Planned Resources (Winter Rating) Identified by Type (Class 1 - 3 Only) (as of Dec. 31)

Sub-Region	Type	2009	2010	2011	2012	2013	2014	2015	2016	2017	Total
Canada	Wind	120	180	0	0	0	0	0	0	0	300
Canada	Hydro	92	687	435	0	0	0	0	0	0	1,214
Canada	Thermal	(41)	(279)	344	0	0	0	0	0	0	24
Canada	Solar	0	0	0	0	0	0	0	0	0	0
Canada	Other	82	0	0	0	0	0	0	0	0	82
	Total	253	588	779	0	0	0	0	0	0	1,620

Canada Planned Resources (Winter Rating) Identified by Type (Class 4 - 5 Only) (as of Dec. 31)

Sub-Region	Type	2009	2010	2011	2012	2013	2014	2015	2016	2017	Total
Canada	Wind	608	1,680	0	0	0	0	0	0	0	2,288
Canada	Hydro	0	52	0	0	0	0	0	0	0	52
Canada	Thermal	455	1,380	0	0	0	0	0	0	0	1,835
Canada	Solar	0	0	0	0	0	0	0	0	0	0
Canada	Other	0	93	0	0	0	0	0	0	0	93
	Total	1,063	3,205	0	0	0	0	0	0	0	4,268

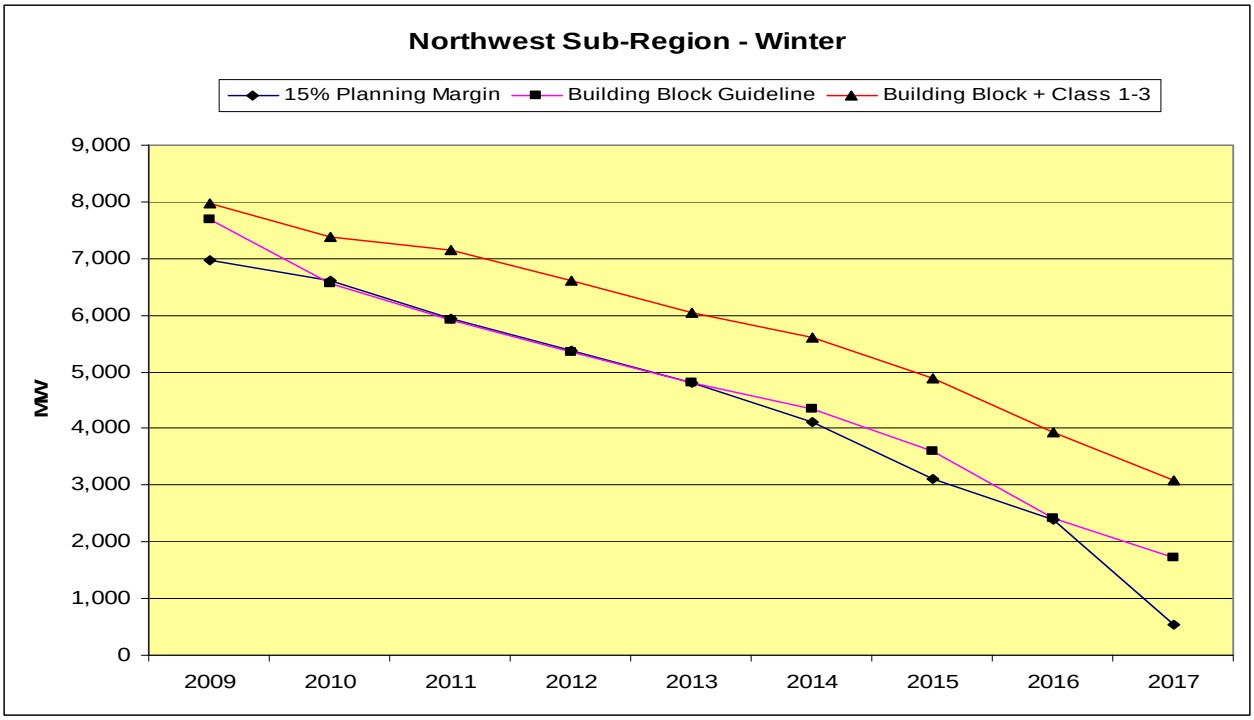
The data presented in the above charts are the reported winter ratings for projects planned to be added during the calendar years.

[20] http://www.energyplan.gov.bc.ca/

Northwest

Sub-Region	Zones in Sub-Region
Northwest	COB, Montana, Pacific Northwest

Graph 7 - Comparison of Northwest Sub-Region Power Supply Margin (MW)



The consistent capacity surplus may not be sustainable over multiple prolonged cold spells. This peak hour capacity assessment may not fully address the complicated energy limitations that apply to the Northwest hydro system.

The following tables show the addition of wind resources only as Class 4 & 5 resources, which are considered highly uncertain in the PSA. The addition of new wind resources in the Northwest may be considerably more certain than indicated by the Class 4 or 5 classification status, as demonstrated by a recent transmission service agreement solicitation on the part of Bonneville Power Administration (BPA). On June 16, 2008, BPA concluded the first phase of its Network Open Season (NOS) process. This resulted in Precedent Transmission Service Agreements being signed with the developers of 4,716 MW of wind resources. At this point, there are almost 1,500 MW of wind on BPA's system and approximately 3,000 MW total expected by the end of 2009. Therefore, it should be noted that there is an expectation that significant amounts of new wind resources will be constructed in the Northwest. However, these wind resources are unlikely to contribute significantly toward capacity adequacy. In its recent resource adequacy assessment for the Pacific Northwest, the Northwest Power and Conservation Council only counts wind at 5% of its installed capacity as contributing toward sustained peak capacity needs. On a peak hour basis, wind capacity may contribute even less than 5% installed capacity toward capacity adequacy.

Northwest Planned Resources (Winter Rating) Identified by Class (as of Dec. 31)

Sub-region	Class	2009	2010	2011	2012	2013	2014	2015	2016	2017	Total
Northwest	1	0	(6)	0	0	0	0	0	0	0	(6)
Northwest	2	0	0	0	0	0	0	0	0	0	0
Northwest	3	7	7	7	7	0	0	0	0	0	28
Total	1-3	7	1	7	7	0	0	0	0	0	22
Northwest	4	124	0	0	0	25	25	25	0	0	199
Northwest	5	383	448	268	99	0	0	0	0	0	1,198
Total	4-5	507	448	268	99	25	25	25	0	0	1,397

Northwest Planned Resources (Winter Rating) Identified by Type (Class 1 - 3 Only) (as of Dec. 31)

Sub-Region	Type	2009	2010	2011	2012	2013	2014	2015	2016	2017	Total
Northwest	Wind	0	0	0	0	0	0	0	0	0	0
Northwest	Hydro	7	1	7	7	0	0	0	0	0	22
Northwest	Thermal	0	0	0	0	0	0	0	0	0	0
Northwest	Solar	0	0	0	0	0	0	0	0	0	0
Northwest	Other	0	0	0	0	0	0	0	0	0	0
	Total	7	1	7	7	0	0	0	0	0	22

Northwest Planned Resources (Winter Rating) Identified by Type (Class 4 - 5 Only) (as of Dec. 31)

Sub-Region	Type	2009	2010	2011	2012	2013	2014	2015	2016	2017	Total
Northwest	Wind	507	448	0	99	0	0	0	0	0	1,054
Northwest	Hydro	0	0	0	0	25	25	25	0	0	75
Northwest	Thermal	0	0	268	0	0	0	0	0	0	268
Northwest	Solar	0	0	0	0	0	0	0	0	0	0
Northwest	Other	0	0	0	0	0	0	0	0	0	0
	Total	507	448	268	99	25	25	25	0	0	1,397

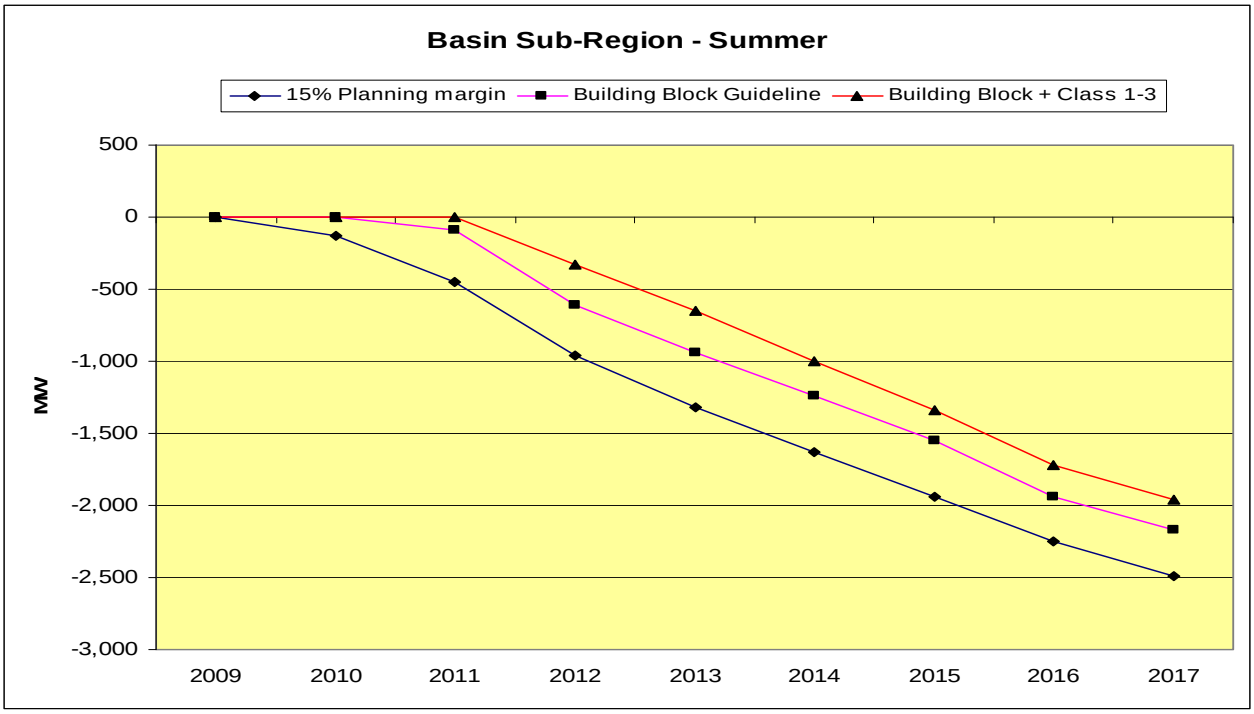
The data presented in the above charts are the reported winter ratings for projects planned to be added during the calendar years.

Refer to the attached (Attachment 7) Pacific Northwest Energy Assessment for more information.

Basin

Sub-Region	Zones in Sub-Region
Basin	Idaho, No. Nevada, Utah, IPP

Graph 8 - Comparison of Basin Sub-Region Power Supply Margin (MW)



The load requirements for the Basin sub-region are met through 2009 or later, depending on the case. Note that the following table indicates that several new Class 4 and Class 5 projects were reported that are not currently under construction, and thus excluded for this assessment. If these Class 4 and 5 projects are completed in the time frames reported, the Basin sub-region will likely have a positive supply/demand balance during the study period.

Basin Planned Resources (Summer Rating) Identified by Class (as of Dec. 31)

Sub-region	Class	2009	2010	2011	2012	2013	2014	2015	2016	2017	Total
Basin	1	12	0	0	0	0	0	0	0	0	12
Basin	2	27	47	38	25	0	0	0	0	0	137
Basin	3	0	15	30	19	0	0	0	0	0	64
Total	1-3	39	62	68	44	0	0	0	0	0	213
Basin	4	200	54	(10)	0	0	0	750	750	0	1,744
Basin	5	161	0	0	1,016	135	0	(83)	0	0	1,229
Total	4-5	361	54	(10)	1,016	135	0	667	750	0	2,973

Basin Planned Resources (Summer Rating) Identified by Type (Class 1 - 3 Only) (as of Dec. 31)

Sub-Region	Type	2009	2010	2011	2012	2013	2014	2015	2016	2017	Total
Basin	Wind	0	0	0	0	0	0	0	0	0	0
Basin	Hydro	0	0	0	0	0	0	0	0	0	0
Basin	Thermal	0	20	30	19	0	0	0	0	0	68
Basin	Solar	0	0	0	0	0	0	0	0	0	0
Basin	Other	39	42	38	25	0	0	0	0	0	145
	Total	39	62	68	44	0	0	0	0	0	213

Basin Planned Resources (Summer Rating) Identified by Type (Class 4 - 5 Only) (as of Dec. 31)

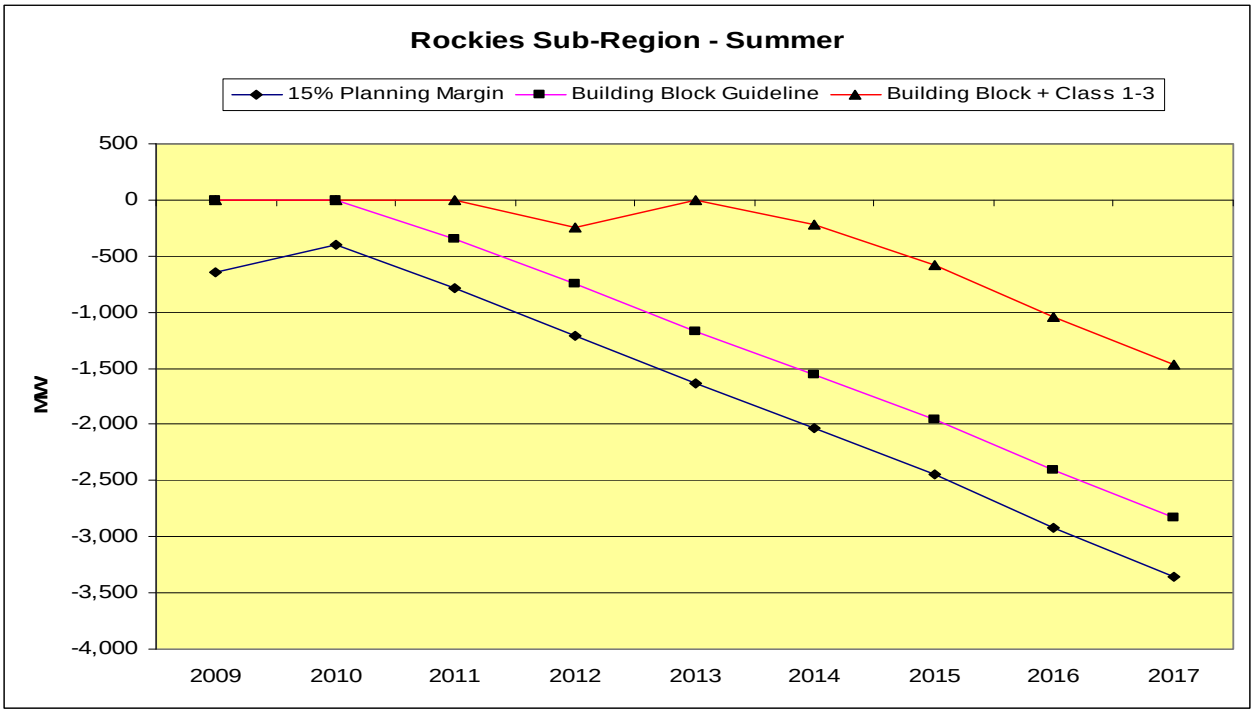
Sub-Region	Type	2009	2010	2011	2012	2013	2014	2015	2016	2017	Total
Basin	Wind	361	0	0	0	198	0	0	0	0	559
Basin	Hydro	0	0	0	0	0	0	0	0	0	0
Basin	Thermal	0	19	(10)	1,016	(63)	0	667	750	0	2,379
Basin	Solar	0	0	0	0	0	0	0	0	0	0
Basin	Other	0	35	0	0	0	0	0	0	0	36
	Total	361	54	(10)	1,016	135	0	667	750	0	2,973

The data presented in the above charts are the reported summer ratings for projects planned to be added during the calendar years.

Rockies

Sub-Region	Zones in Sub-Region
Rockies	Colorado-East, Colorado-West, Wyoming

Graph 9 - Comparison of Rockies Sub-Region Power Supply Margin (MW)



In general, the results predict that additional resources are needed before 2011 in order to meet the forecasted load requirements. Several large projects reported in Class 4 and 5 were excluded from the case studies. Off-setting this, the two 700 MW Holcomb units, one of them in Class 3 and the other in Class 4, are facing substantial political opposition in Kansas and it does not appear that they will be completed as scheduled. It appears that resources in addition to the proposed projects in Class 4 and Class 5 are needed to avoid deficits in the Rockies sub-region. The Rockies sub-region is not transmission constrained at its borders, but it is indirectly impacted by the North-South split because of the limited interconnection with the Northwest. In fact, imports from MAPP and SPP are a possible source of moderate amounts of capacity at any time.

Rockies Planned Resources (Summer Rating) Identified by Class (as of Dec. 31)

Sub-region	Class	2009	2010	2011	2012	2013	2014	2015	2016	2017	Total
Rockies	1	0	750	0	0	0	0	0	0	0	750
Rockies	2	0	(4)	0	0	4	0	0	0	0	0
Rockies	3	21	121	420	44	726	0	0	0	0	1,332
Total	1-3	21	867	420	44	730	0	0	0	0	2,082
Rockies	4	99	0	0	0	0	700	0	0	0	799
Rockies	5	0	99	198	0	0	0	0	0	0	297
Total	4-5	99	99	198	0	0	700	0	0	0	1,096

Rockies Planned Resources (Summer Rating) Identified by Type (Class 1 – 3 Only) (as of Dec. 31)

Sub-Region	Type	0	0	0	0	0	0	0	0	0	Total
Rockies	Wind	0	0	0	0	0	0	0	0	0	0
Rockies	Hydro	0	0	0	0	0	0	0	0	0	0
Rockies	Thermal	21	867	420	44	730	0	0	0	0	2,082
Rockies	Solar	0	0	0	0	0	0	0	0	0	0
Rockies	Other	0	0	0	0	0	0	0	0	0	0
	Total	21	867	420	44	730	0	0	0	0	2,082

Rockies Planned Resources (Summer Rating) Identified by Type (Class 4 – 5 Only) (as of Dec. 31)

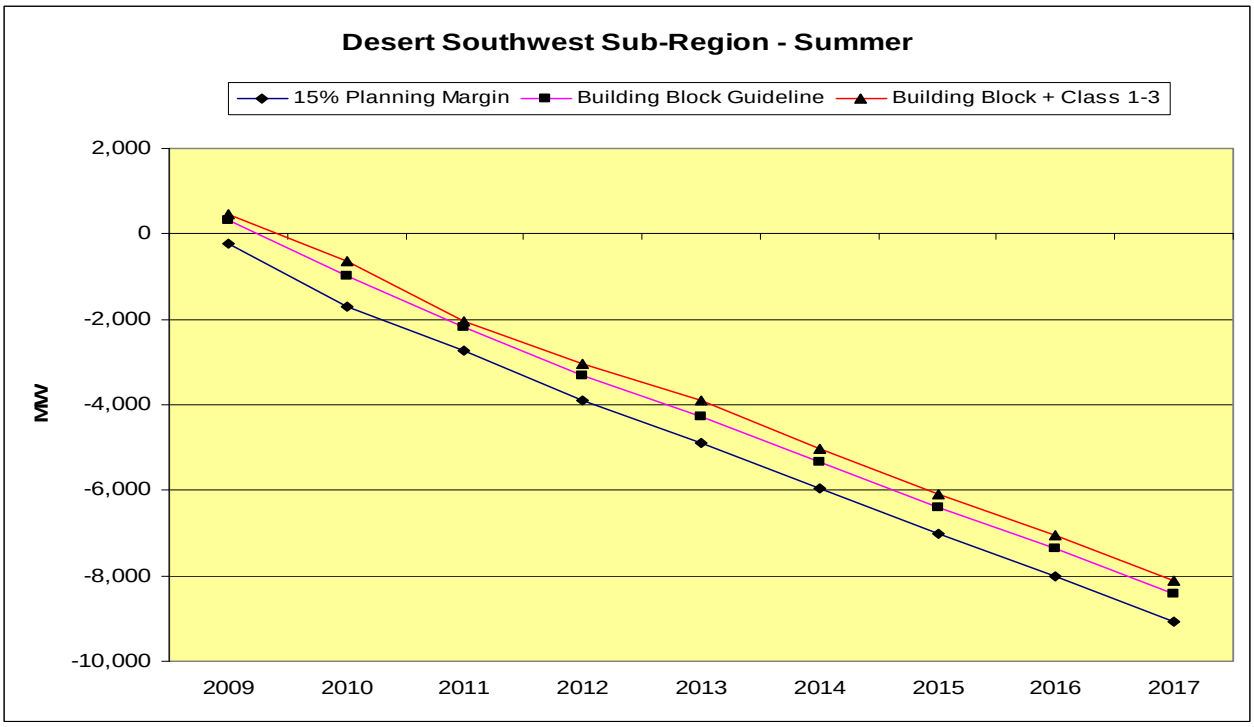
Sub-Region	Type	2009	2010	2011	2012	2013	2014	2015	2016	2017	Total
Rockies	Wind	99	99	198	0	0	0	0	0	0	396
Rockies	Hydro	0	0	0	0	0	0	0	0	0	0
Rockies	Thermal	0	0	0	0	0	700	0	0	0	700
Rockies	Solar	0	0	0	0	0	0	0	0	0	0
Rockies	Other	0	0	0	0	0	0	0	0	0	0
	Total	99	99	198	0	0	700	0	0	0	1,096

The data presented in the above charts are the reported summer ratings for projects planned to be added during the calendar years.

Desert Southwest

Sub-Region	Zones in Sub-Region
Desert SW	Arizona, IID, Four Corners, New Mexico, Palo Verde, So. Nevada

Graph 10 - Comparison of Desert Southwest Sub-Region Power Supply Margin (MW)



The results show that the Desert Southwest sub-region has a negative Power Supply Margin, depending on the case study, as early as 2009. Several large projects were reported in Class 4 and Class 5 which were excluded from the case studies. Also excluded from the case studies are several natural gas plants announced by SRP after the data for the PSA studies was locked. However, it appears that even with the addition of the 1,700 MW of Class 4 and Class 5 resources and the 500 MW of SRP projects, the Desert Southwest is still in need of substantial resource additions.

Desert Southwest Planned Resources (Summer Rating) Identified by Class (as of Dec. 31)

Sub-region	Class	2009	2010	2011	2012	2013	2014	2015	2016	2017	Total
Desert SW	1	606	0	484	0	0	0	0	0	0	1,090
Desert SW	2	0	0	0	(18)	0	0	0	0	0	(18)
Desert SW	3	32	46	0	280	0	0	0	0	0	358
Total	1-3	638	46	484	262	0	0	0	0	0	1,430
Desert SW	4	141	1	142	601	2	2	0	0	0	889
Desert SW	5	72	165	266	(395)	150	255	70	(80)	328	831
Total	4-5	213	166	408	206	152	257	70	(80)	328	1,720

Desert Southwest Planned Resources (Summer Rating) Identified by Type (Class 1 – 3 Only) (as of Dec. 31)

Sub-Region	Type	2009	2010	2011	2012	2013	2014	2015	2016	2017	Total
Desert SW	Wind	0	0	0	0	0	0	0	0	0	0
Desert SW	Hydro	0	0	0	0	0	0	0	0	0	0
Desert SW	Thermal	606	46	484	(18)	0	0	0	0	0	1,118
Desert SW	Solar	0	0	0	280	0	0	0	0	0	280
Desert SW	Other	32	0	0	0	0	0	0	0	0	32
	Total	638	46	484	262	0	0	0	0	0	1,430

Desert Southwest Planned Resources (Summer Rating) Identified by Type (Class 4 – 5 Only) (as of Dec. 31)

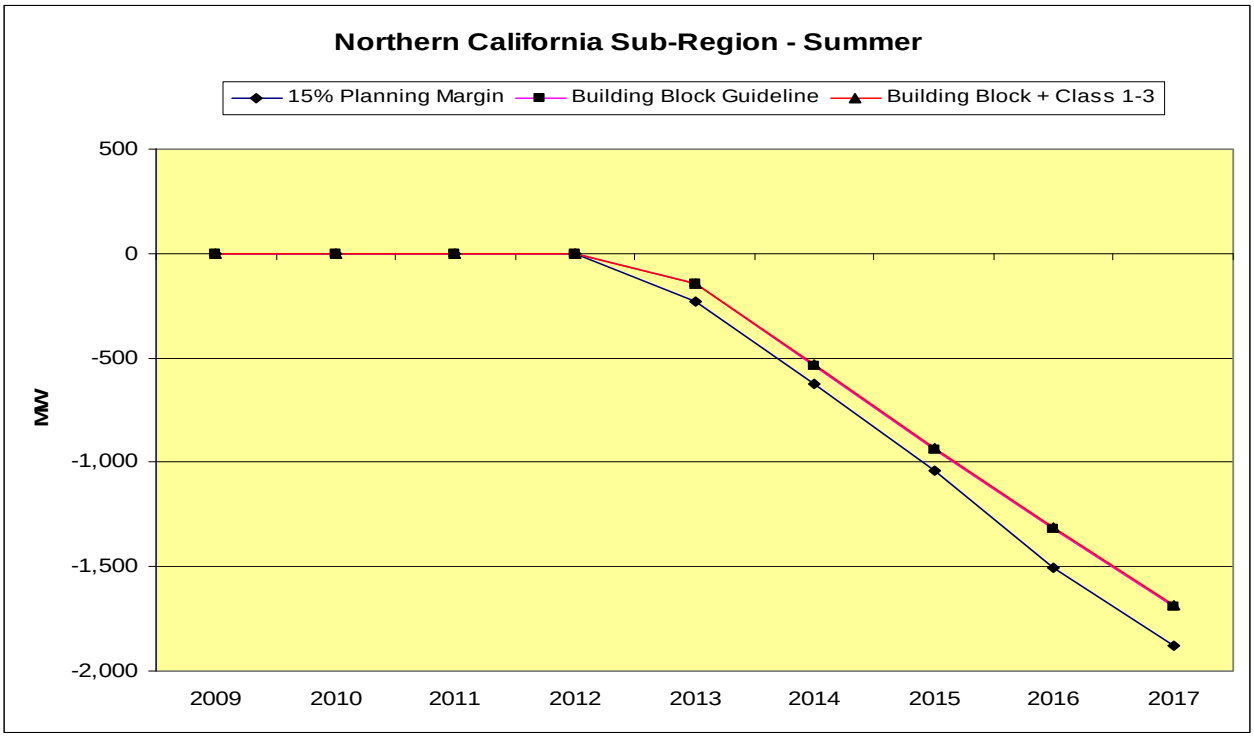
Sub-Region	Type	2009	2010	2011	2012	2013	2014	2015	2016	2017	Total
Desert SW	Wind	0	0	0	0	0	0	0	0	0	0
Desert SW	Hydro	0	0	0	0	0	0	0	0	0	0
Desert SW	Thermal	212	96	406	205	150	250	70	(80)	328	1,637
Desert SW	Solar	1	1	2	1	2	2	0	0	0	9
Desert SW	Other	0	69	0	0	0	5	0	0	0	74
	Total	213	166	408	206	152	257	70	(80)	328	1,720

The data presented in the above charts are the reported summer ratings for projects planned to be added during the calendar years.

Northern California

Sub-Region	Zones in Sub-Region
No. CA	Central CA, Northern CA, San Francisco, SMUD

Graph 11 - Comparison of Northern California Sub-Region Power Supply Margin (MW)



The load requirements for the Northern California sub-region are met through 2012. If the resource additions in Class 4 and Class 5 are constructed in the time frame reported, the Northern California sub-region would have adequate resources throughout the PSA study. The zero Power Supply Margin in earlier years is a reflection of the transfers modeled by SAM into and out of the Northern California sub-region. This contrasts with the Southern California sub-region, which consists of zones that are less well connected to other sub-regions. These Northern California results are consistent with resource adequacy assessments conducted by California entities.

The North-South split doesn't affect the Northern California sub-region as early as it does Southern California and the Desert Southwest due to its proximity to the Northwest, the limited transfer capacity between Central and Southern California zones, and the dispatch method used by the SAM model. Northern California, in essence, is given the first opportunity to use the imports from the Northwest.

No. California Planned Resources (Summer Rating) Identified by Class (as of Dec. 31)

Sub-region	Class	2009	2010	2011	2012	2013	2014	2015	2016	2017	Total
No. CA	1	401	44	0	0	0	0	0	0	0	445
No. CA	2	0	0	0	0	0	0	0	0	0	0
No. CA	3	0	0	0	0	0	0	0	0	0	0
Total	1-3	401	44	0	0	0	0	0	0	0	445
No. CA	4	0	0	48	0	0	0	0	0	0	48
No. CA	5	74	2,255	143	250	300	0	390	0	0	3,412
Total	4-5	74	2,255	191	250	300	0	390	0	0	3,460

No. California Planned Resources (Summer Rating) Identified by Type (Class 1 – 3 Only) (as of Dec. 31)

Sub-Region	Type	2009	2010	2011	2012	2013	2014	2015	2016	2017	Total
No. CA	Wind	0	0	0	0	0	0	0	0	0	0
No. CA	Hydro	0	0	0	0	0	0	0	0	0	0
No. CA	Thermal	401	44	0	0	0	0	0	0	0	445
No. CA	Solar	0	0	0	0	0	0	0	0	0	0
No. CA	Other	0	0	0	0	0	0	0	0	0	0
	Total	401	44	0	0	0	0	0	0	0	445

No. California Planned Resources (Summer Rating) Identified by Type (Class 4 – 5 Only) (as of Dec. 31)

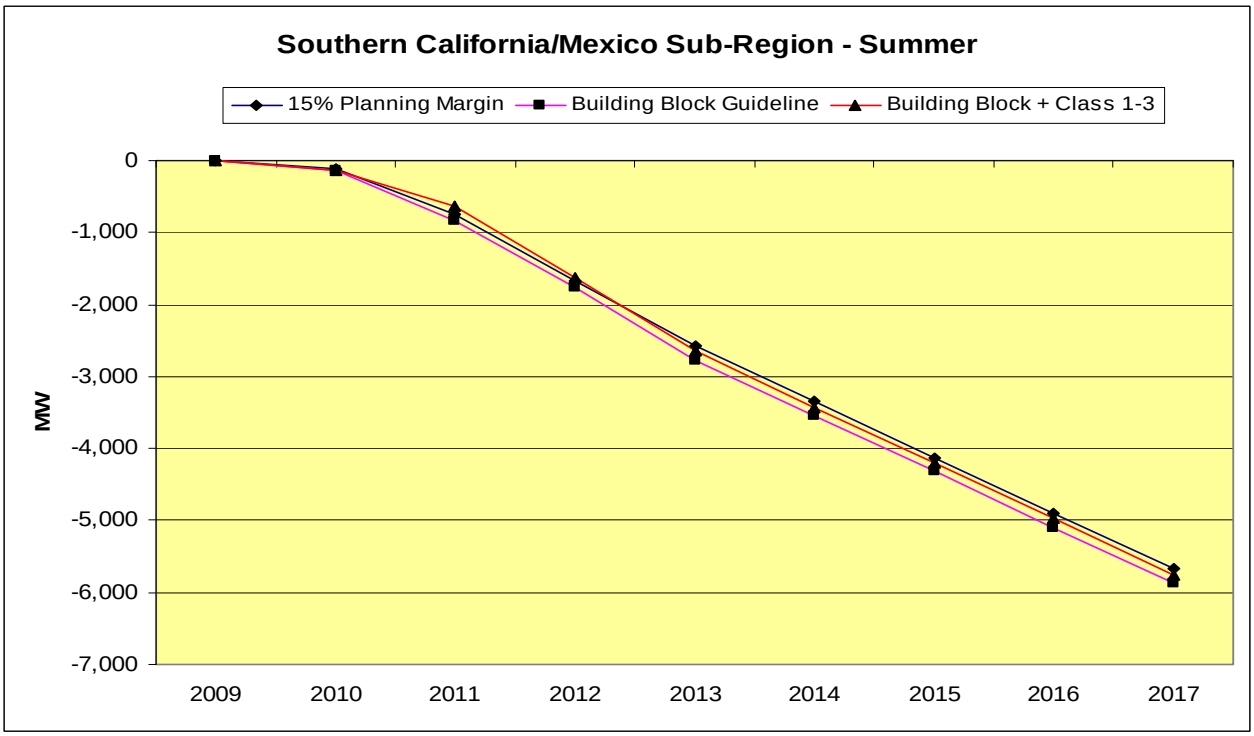
Sub-Region	Type	2009	2010	2011	2012	2013	2014	2015	2016	2017	Total
No. CA	Wind	0	0	143	0	0	0	0	0	0	143
No. CA	Hydro	0	0	0	0	0	0	390	0	0	390
No. CA	Thermal	74	2,255	48	250	300	0	0	0	0	2,927
No. CA	Solar	0	0	0	0	0	0	0	0	0	0
No. CA	Other	0	0	0	0	0	0	0	0	0	0
	Total	74	2,255	191	250	300	0	390	0	0	3,460

The data presented in the above charts are the reported summer ratings for projects planned to be added during the calendar years.

Southern California/Mexico

Sub-Region	Zones in Sub-Region
So. CA/MX	CFE-Mexico, Southern CA, San Diego, LADWP

Graph 12 - Comparison of Southern California/Mexico Sub-Region Power Supply Margin (MW)



The results of this assessment predict that the load requirements in Southern California/Mexico can be met through 2009. This is consistent with California's own assessment which shows Southern California needing resources earlier than Northern California. Where the Power Supply Margin is positive, this is due to a surplus in Mexico, not Southern California. In each of the summer cases Southern California is reliant on imports from other sub-regions to meet its load requirements (see Tables in Attachment 3).

Many large projects were reported in Class 4 and Class 5 which were excluded from the case studies. However, it appears that even if the 2,500 MW of Class 4 and Class 5 additions are completed as reported, there is still a need for substantial additional resources to be built.

So. California/Mex. Planned Resources (Summer Rating) Identified by Class (as of Dec. 31)

Sub-region	Class	2009	2010	2011	2012	2013	2014	2015	2016	2017	Total
So. CA/MX	1	400	127	103	0	0	0	0	0	0	630
So. CA/MX	2	0	0	0	0	0	0	0	0	0	0
So. CA/MX	3	0	0	0	0	0	0	0	0	0	0
Total	1-3	400	127	103	0	0	0	0	0	0	630
So. CA/MX	4	500	0	650	117	0	0	0	0	0	1,267
So. CA/MX	5	223	25	311	91	311	0	0	0	270	1,231
Total	4-5	723	25	961	208	311	0	0	0	270	2,498

So. California/Mex. Planned Resources (Summer Rating) Identified by Type (Class 1 – 3 Only) (as of Dec. 31)

Sub-Region	Type	2009	2010	2011	2012	2013	2014	2015	2016	2017	Total
So.CA/MX	Wind	120	0	0	0	0	0	0	0	0	120
So.CA/MX	Hydro	20	20	103	0	0	0	0	0	0	143
So.CA/MX	Thermal	259	0	0	0	0	0	0	0	0	259
So.CA/MX	Solar	0	0	0	0	0	0	0	0	0	0
So.CA/MX	Other	1	107	0	0	0	0	0	0	0	108
	Total	400	127	103	0	0	0	0	0	0	630

So. California/Mex. Planned Resources (Summer Rating) Identified by Type (Class 4 – 5 Only) (as of Dec. 31)

Sub-Region	Type	2009	2010	2011	2012	2013	2014	2015	2016	2017	Total
So.CA/MX	Wind	0	0	0	0	0	0	0	0	0	0
So.CA/MX	Hydro	0	3	20	2	0	0	0	0	0	25
So.CA/MX	Thermal	723	22	941	140	311	0	0	0	0	2,137
So.CA/MX	Solar	0	0	0	0	0	0	0	0	270	270
So.CA/MX	Other	0	0	0	66	0	0	0	0	0	66
	Total	723	25	961	208	311	0	0	0	270	2,498

The data presented in the above charts are the reported summer ratings for projects planned to be added during the calendar years.

Additional Assumptions

The following assumptions were made for this assessment:

- The input data represents demand forecasts and resource plans submitted between December 2007 and February 2008. New generation projects announced after these submittals are not included in the resource totals.
- Non-coincidental demands were used such that the monthly peak zonal demands are the sum of the control area peak demands for each zone.
- July data was used for the summer peak period for each year. December data was used for the winter peak period.
- This assessment assumes that the demand for a given zone is the sum of the Balancing Authority customer demands within that zone. This differs from the "load requirement" concept where the load that must be served is the customer demand plus the firm exports. Under most circumstances, the application of "forced transfers" to accommodate firm exports would tend to undermine the model solution.
- Peak demands for CISO, PACE, PSC, WACM, and WALC were allocated to SAM zones based on the following ratios reported by the PCC representatives as part of their annual review. In the future, it may be desirable for those entities to report the L&R data for each zone rather than at an aggregated level which is then disaggregated for modeling purposes.

Table 13 - Percent of Control Area Demand Allocated to Zones

Zones \ Balancing Authority	CISO	PACE	PSC	WACM	WALC
Arizona					72%
Colorado, East			88%	50%	
Colorado, West			12%	28%	
Idaho		8.2%			
New Mexico					28%
Utah		77.3%			
Wyoming		14.5%		22%	
California, North	36.0%				
California, Central	6.5%				
California, South	45.0%				
California, San Diego	10.0%				
California, San Fran.	2.5%				

- Since the goal of the study was assessing the ability of the system to meet load, and not any particular economic outcome, the summary resources in each zone were all assigned the same costs (US Hydro = $5/MWH, Canadian Hydro = $6/MWH, Non-hydro = $20/MWH), with the exception of Palo Verde ($15/MWH).
- The adjustments (forced transfers) for external generation (generation in one zone owned by an LSE in another zone) that were used in the studies were for Bridger, Colstrip, Craig, Four Corners, Hayden, Hoover, Intermountain, Navajo, Palo Verde, San Juan, and San Onofre. No other adjustments were made for other joint plants or firm purchases.
- Except for the 325 MW contractual imports into New Mexico from the Southwest Power Pool (SPP), ties to the Mid-Continent Area Power Pool (MAPP) and SPP are not modeled since this

would require generation and/or demand to be associated with these external regions. Additional long term contracts that result in consistent imports or exports could be represented in the model if the Loads and Resources Subcommittee determines that this is appropriate.

- The model freely transfers resources from areas with surplus generation to deficit areas, considering transfer path constraints and transmission losses. Simultaneous flows, loop flows, and other transfer restrictions are approximated by the restricted transfer limits that were used in the studies, but the model is a transport model, not a power flow model.
- The model is not intended to measure the Power Supply Margins in the individual Balancing Authorities (unless the zone definition and transfer capabilities exactly match the control area). The model assumes that there are no constraints internal to a zone.

Observations and Caveats

1. This assessment is based on the physical ability of the interconnection to supply all loads regardless of contractual obligations. This means that the model uses economic relationships to calculate transfers between zones within the assigned limits. In reality, the ideal solutions may be difficult to duplicate in the operational environment. System operation for contract obligations and other conditions could adversely affect the availability of resources, and could impact the amount and timing of power supply deficiencies in specific zones.
2. Using non-coincidental demands tends to overstate the simultaneous demand. Preliminary studies indicate that the simultaneous combined peak demand for WECC has a variance of 2% to 4%, compared to the non-simultaneous demand.
3. Surplus generation in the Pacific Northwest zone was often stranded due to transmission limitations (see North-South Split Diagram on page 21 for constraint points). However, neither the summer nor the winter analysis for the Northwest sub-region captures the limitations on the ability of the hydro system to sustain output levels beyond a single hour. Because of this limitation, the reported surpluses, both for Northwest sub-region's load and for potential export to other sub-regions of the West, may be unrealistically high. Northwest entities are continuing to work on a more realistic characterization of the ability of the hydro system to meet loads and export markets.
4. There were cases where surplus resources were available, but transfer path limitations prevented the surplus from reaching the areas with deficits. Whenever an individual zone became deficit while the Interconnection overall had a surplus (sum of zonal surpluses/deficits were greater than zero), there were one or more transfer path limitations between the surplus area(s) and the deficit area(s).
5. The assessment results for the period beyond 2013 do not represent a realistic picture of future Power Supply Margins, but do represent a picture of future resource needs for the given load forecast and transmission system. The addition of generation plants that are not accounted for in the current data should be expected. There is a point where the results shift from a determination of Power Supply Margin to a determination of future needs.
6. The model assumes an optimistic efficiency where resources and transmission become immediately available as necessary to meet demand requirements. System operation to meet contract obligations and other conditions could adversely affect the availability of resources, and could impact the amount and timing of power supply deficiencies in specific zones.

7. The impact of a competitive wholesale market design on Power Supply Margin assessments should be considered in the determination of supply shortfalls. While it is important to the effective functioning of the market that opportunities for investment in new generation be identified, recognition needs to be given to the ability of the market to respond in the timing horizon covered by this Power Supply Assessment.

Recommendations for Future Assessments

1. The hydro generation capability in the Northwest sub-region has limitations beyond those assumed for this assessment. The seasonal operation of the coordinated hydro system is subject to dozens of parameters to accommodate the various interests in the river systems. Northwest entities are continuing to work on a more realistic characterization of the ability of the hydro system to meet loads and export markets. If the effect of these factors can be determined, they should be addressed in future assessments.

2. Future plans for the model may include conducting probabilistic or stochastic studies to study the effects of random uncertainties. This would require that the members provide additional information such as resource forced outage rates, resource operating costs, demand variations, transmission loss data, and transmission wheeling costs.

3. Planned changes to the transfer path capabilities must be reflected in the model to accurately measure their effect on the results. Since they would usually directly affect the results, only changes that are highly probable should be taken into consideration.

4. The effects of fuel diversity and availability should be modeled in future assessments. The prevalence of natural gas and coal fired generation in WECC has raised concerns about the interdependencies of electricity and fuel supply. Improved analyses should evaluate the impact of fuel shortages due to fuel supply interruptions or demand spikes.

5. Although an energy assessment for one zone (the Pacific Northwest) is included, expanding to other sub-regions and zones where relevant for WECC is still a goal for the future. While WECC recognizes the need for an assessment of energy supplies, it is expected that the data and manpower requirements for energy assessments would be significantly higher than for this peak hour capacity assessment. A more sophisticated model would also be needed.

6. The growth of short lead time resources requires a review of the resource classification and modeling approaches.

Attachment 1: Comparison of LTRA and PSA Results

The NERC required Long-Term Reliability Assessment (LTRA) and the WECC produced Power Supply Assessment (PSA) are attempts to analyze the potential for electricity supply shortages, over a 10 year period, based on BA reported demand, resources, and transmission data. Although efforts have been made in recent years to better align the results reported in the LTRA and the PSA, such as reflecting the same surplus or deficit for each of the sub-regions, and including non-firm load in the demand obligation, there are still differences in the reporting requirements that make a comparison between the two reports difficult. These reporting requirements include the use of different geographic sub-regional boundaries, and the methods used to calculate seasonal peak demand.

NERC requires that the assessment results of the LTRA be reported in four major sub-regions, Northwest, Rockies, Desert Southwest, and California–Mexico. However, NERC also requires that the reliability results for Canada, Mexico, and the United States be reported separately. To accomplish this reporting requirement WECC separates the Northwest sub-region into two sections, the Northwest Power Pool–US (NWUS), and the Northwest Power Pool–Canada (NWCN). The California–Mexico sub-region is also separated into two sections, the California–Mexico (US–CMUS) and the California–Mexico (Mexico–CMMX). The PSA reports the results of the reliability assessments in seven sub-regions, Canada, Northwest, Basin, Rockies, Desert Southwest, Northern California, and Southern California/Mexico. The table below details the sub-regional differences. This mismatch of sub-regions makes a one-to-one comparison of results difficult.

Table 14 – PSA vs. LTRA Sub-Regional Zones

PSA Sub-Region	Zones in PSA Sub-Region	LTRA Major Sub-Region	LTRA Sub-Regional Sections	Zones in LTRA Sub-Region
Northwest	COB, Montana, Oregon, Washington	Northwest	Northwest Power Pool US (NWUS)	Montana, Oregon, Washington, Idaho, No. Nevada, Utah, Wyoming - West
Canada	Alberta, British Columbia		Northwest Power Pool–Canada (NWCN)	Alberta, British Columbia
Rockies	Colorado - East, Colorado - West, Wyoming	Rockies		Colorado - East, Colorado - West, Wyoming - East
Desert Southwest	Arizona, Four Corners, Imperial Irrigation District, New Mexico, Palo Verde, So. Nevada	Desert Southwest		Arizona, Imperial Irrigation District, New Mexico, So. Nevada
Northern California	Central CA, Northern CA, Sacramento Municipal Utility District, San Francisco	California/Mexico	California–Mexico (US–CMUS)	Los Angeles Department of Water and Power, San Diego, Southern CA, Central CA, Northern CA, Sacramento Municipal Utility District, San Francosco
Southern California/Mexico	Comision Federal de Electricidad, Los Angeles Department of Water and Power, San Diego, Southern CA		California–Mexico (Mexico–CMMX).	Comision Federal de Electricidad
Basin	Idaho, IPP, No. Nevada, Utah			

Although the geographic boundaries in the LTRA and the PSA are not consistent for all sub-regions, the Canada and Desert Southwest regions are the same and a comparison of the assessment results for these regions can be done. The LTRA and the PSA assessments are calculated using the same underlying data, and regional boundaries, and the results from the two reports are equivalent. For example, the NWCN results in the LTRA and the Canada results in

the PSA indicate that Canada could be deficit as early as the winter of 2008. Likewise, the Desert Southwest results for both the LTRA and the PSA reflect a surplus of capacity through at least 2009. However, a similar comparison for the NWUS from the LTRA and the Northwest sub-region of the PSA can not be done because the sub-regional boundaries are not the same. The LTRA defines the NWUS as all or major portions of the states of Idaho, Montana, Nevada, Oregon, Utah, Washington, and Wyoming. The PSA defines the Northwest as the states of Montana, Oregon, and Washington, and a portion of Idaho. The state of Utah and portions of the states of Idaho and Nevada are broken out separately in the PSA as the Basin sub-region, with Wyoming being included in the Rockies sub-region. Therefore, although the underlying data used in these reports is the same, the difference in geographic boundaries prevents an accurate one-to-one comparison. Conversely, the LTRA reports all of California, US–CMUS, as one region, while the PSA reports Northern California and Southern California/Mexico as two separate sub-regions.

The method used to calculate the peak demand of the individual sub-regions also contributes to the difficulty of performing a one-to-one comparison of the LTRA and the PSA. NERC requires that the peak demand used in the LTRA, for both summer and winter seasons, be the reported seasonal peak demands of the sub-region. This is in contrast to the PSA which reports the seasonal, July for summer and December for winter, non-coincidental peak demand of the entire Western Interconnect. Therefore, when calculating the LTRA sub-regional peak demand, unless each Balancing Authority within the sub-region peaks in July, the sub-regional peak demand reported in the LTRA will be different then the sub-regional peak demand reported in the PSA and a one-to-one comparison can not be made.

Attachment 2: Model Outline

A. Description of Model

The "Supply Adequacy Model" (SAM) was developed by the CEC to study the balance between projected demands and resources in California and other WECC areas, taking into consideration transmission limitations between the defined zones or bubbles. The model has the capability to perform either multiple-iteration probabilistic (stochastic) studies or single-iteration deterministic studies. Per instructions from the Loads and Resources Subcommittee, all of the studies conducted for this report were deterministic. If probabilistic studies are requested in the future, it will be necessary to collect additional information from the WECC members.

For the purposes of this assessment, the WECC region is divided into the following zones or "bubbles." The zones are configured around demand centers and transmission hubs. Refer to the topology bubble diagrams for connections between zones.

Alberta	California, SMUD	Montana
Arizona	California, South	Nevada, North
British Columbia	CFE-Mexico	Nevada, South
California, Central	COB	New Mexico
California, IID	Colorado, East	Northwest
California, LADWP	Colorado, West	Palo Verde
California, North	Four Corners	Utah
California, San Diego	Idaho	Wyoming
Calif., San Francisco	IPP	

The COB, Four Corners, IPP, and Palo Verde zones have no load assigned to them.

The following acronym definitions apply to this report.

AZ-NM-SNV	Arizona – New Mexico – Southern Nevada
CA-MX	California – Mexico (CFE –WECC)
CFE	Comision Federal de Electricidad
CAISO	California Independent System Operator
COB	California Oregon Border
CREPC	Committee on Regional Electric Power Cooperation
IID	Imperial Irrigation District
LADWP	Los Angeles Department of Water and Power
MAPP	Mid-Continent Area Power Pool
NWPCC	Northwest Power and Conservation Council
NWPP	Northwest Power Pool
PSC	Public Service of Colorado
RMPA	Rocky Mountain (Colorado – Wyoming)
SMUD	Sacramento Municipal Utility District
SPP	Southwest Power Pool
WACM	WAPA – Colorado / Missouri
WALC	WAPA – Lower Colorado

Model Topology

The topology of the model is shown in the bubble diagrams on pages 57 and 58. The lines between zones are intended to represent transmission connections between the zones and the listed numbers are the transfer path capabilities as reported by the Balancing Authority representatives. The model observes these maximum capabilities as it calculates the solutions for each case. These maximum capabilities represent the Restricted Transfer Capabilities (the limits that may reasonably be expected to apply under simultaneous high seasonal transmission loading conditions).

The capabilities shown with blue highlighting indicate that there are changes in transfer capability during the study period. Transfers with other regional councils such as MAPP and SPP are ignored in this assessment (with the exception of a 325 MW firm purchase in the New Mexico zone), as this would require an assumption regarding the amount of surplus or deficit generation in those councils.

For this assessment, the following transfer capability changes were represented.

- The Palo Verde – Devers 2 project was not included in any of the 2008 PSA studies. If and when this project is approved for construction the effected transfer paths will be modified as appropriate. However, it should be noted that the Desert Southwest is the first sub-region to have a deficit Power Supply Margin limiting the ability to export to other sub-regions,
- Palo Verde – Arizona, new restricted capacity of 8,010 MW west to east due to upgrades including series capacitors, effective May 2008, and
- COB – Northern Nevada, the winter capacity was reduced to zero (0) to reflect the 4,800 MW limit on total deliveries from COB. The full 4,800 MW as assigned for these studies to the COB – Northern California path because the Basin sub-region is not deficit during the study period.

Model Solution & Constraints

Microsoft Solver, a third-party tool included with Excel for solving constraint-based problems, is used to solve the demand/resource balance and calculate the surplus generation and transfers for each zone. The solution seeks the lowest overall resource cost subject to the following constraints:

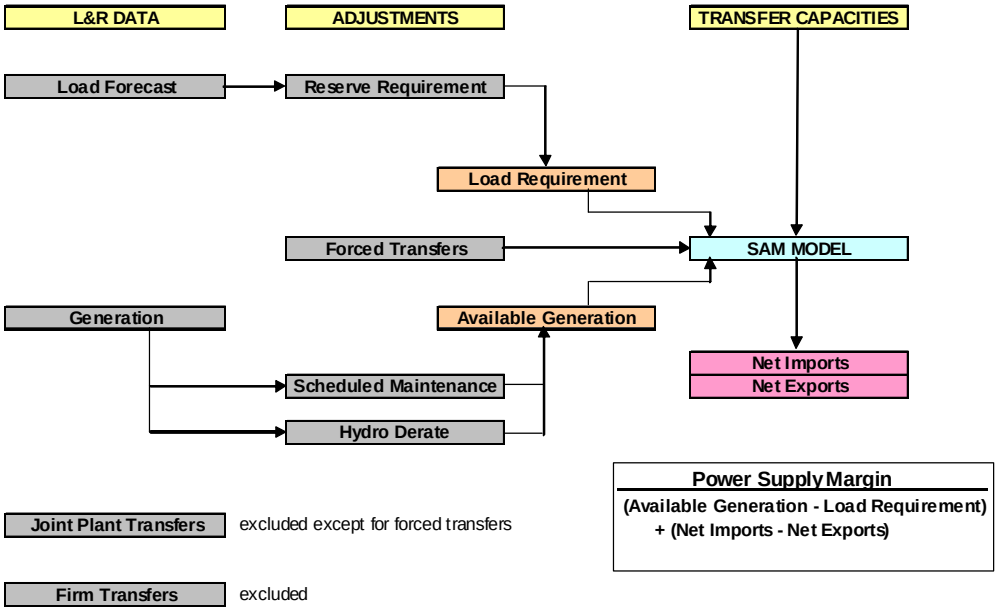
- The demand requirements of each zone must be met (surplus >= 0); but it's possible for a zone to be deficit before solver starts,
- The resource solution for each zone must be equal to or greater than zero,
- The resource solution for each zone must not be greater than the available resources, and
- The resource solution for each zone must not be less than the minimum resource allocation.

The solution uses transfers between zones to export resources from surplus zones to deficit zones. If a deficit is greater than the available transfer capability from the connected zones, then the zone will have a net deficit. The solution will also back off internal generation in a zone if a connecting zone has a surplus that is less expensive and the transfer path has available capability.

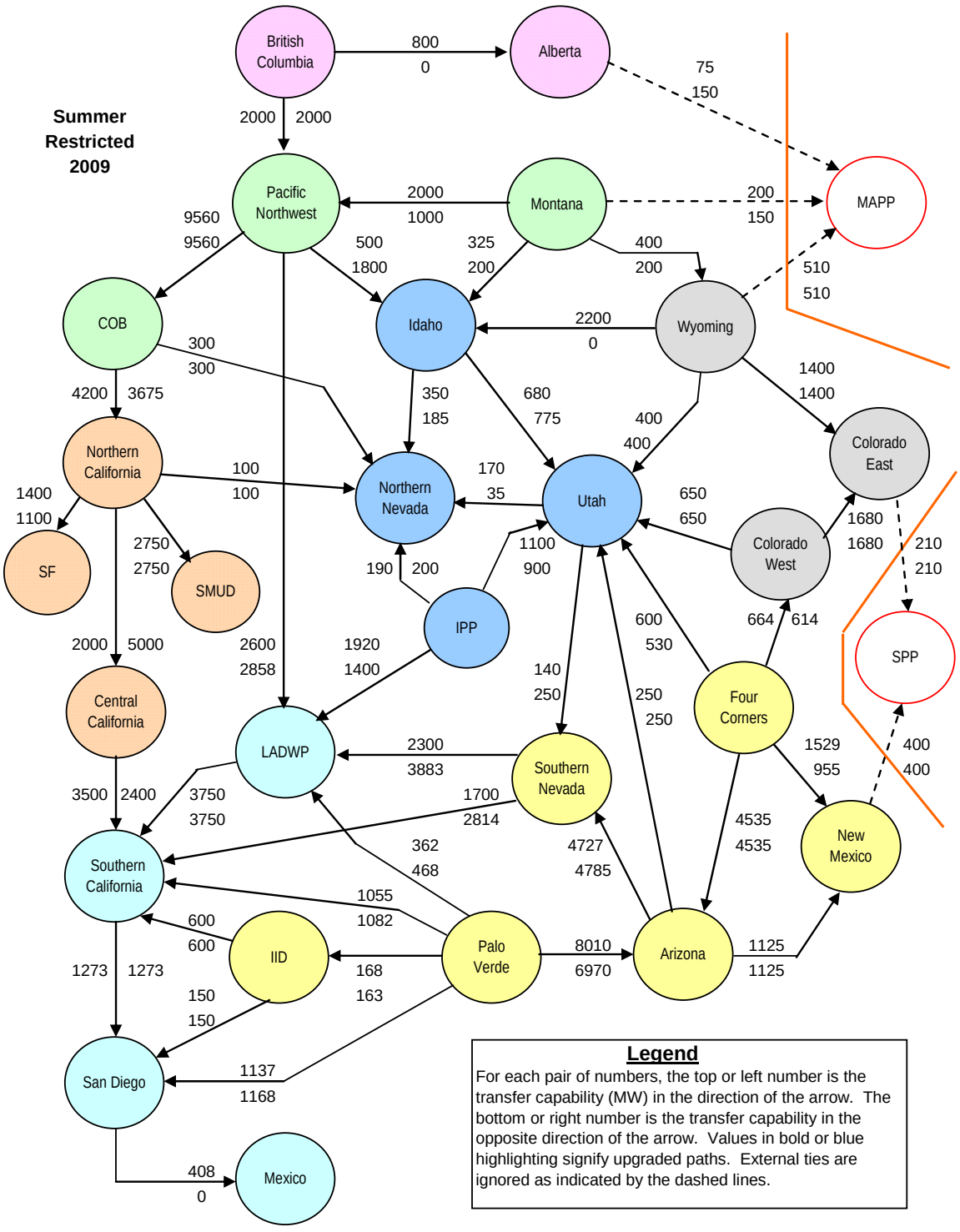
Lower cost resources such as hydro resources are given priority within a zone and as imports, to serve local load and to displace more expensive generation.

The assessment model is designed to measure the supply/demand margins based on forecasts of peak demands and resources. While peak demand forecasts for several years into the future are readily available from the WECC Balancing Authorities, the forecasts of resource additions only exist for a few years into the future. Therefore, the validity of the results decreases as one looks further into the future. The assessment results for the period beyond 2013, or the timeframe where plant additions are incorporated, are not a realistic picture of future Power Supply Margins. The addition of generation plants that are not accounted for in the current data should be expected. There is a point where the results shift from a determination of Power Supply Margin to a determination of future needs.

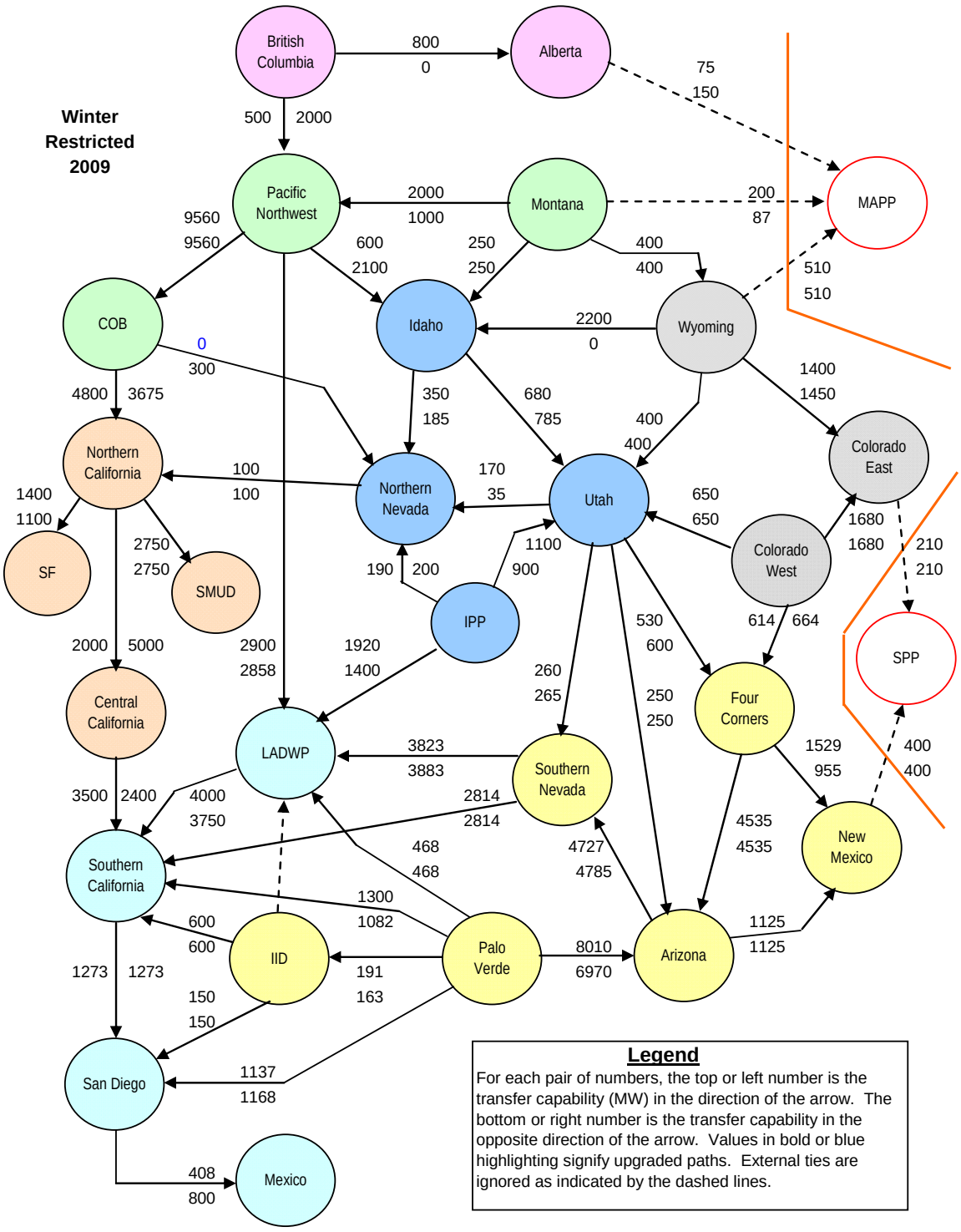
Power Supply Assessment Model



Bubble Diagram #1 – Zone Topology (Summer – Restricted)



Bubble Diagram #2 – Zone Topology (Winter – Restricted)



Legend

For each pair of numbers, the top or left number is the transfer capability (MW) in the direction of the arrow. The bottom or right number is the transfer capability in the opposite direction of the arrow. Values in bold or blue highlighting signify upgraded paths. External ties are ignored as indicated by the dashed lines.

Attachment 3: Study Outline

A. Study Details

The descriptions of the studies and a summary of the results were provided earlier in the Overview section.

Methodology

The assessment utilized a deterministic approach in evaluating the Power Supply Margin[21] in meeting the total peak demand (firm plus non-firm) requirements for the peak hour of the study month. Uncertainties associated with such factors as resource availability and seasonal demand variations were considered explicitly by running additional cases. The primary input variations were:

- The adjustment to the load requirement to model the building block reserve margins and the severe temperature conditions, by escalating the peak demand forecast,
- The inclusion or exclusion of Class 2 and 3 resource additions and retirements, and
- The treatment of resource outages such as scheduled maintenance, generation de-ratings, contingency outages, and forced outages.

The peak demands represent the control area expected peak demand forecasts (1–in–2 probability, defined as 50% probability of not being exceeded) for the study months. It was assumed that the forecast monthly non-coincidental peak demands for each zone will occur at the same time (no diversity). In Case 5, the peak demand escalation was applied directly to the peak demand forecasts. For example, if the peak demand escalation for a summer case was 15%, the July peak demand forecast for each year was multiplied by a factor of 1.15. Peak demand escalation should not be confused with the load growth escalation that is already represented in the peak demand forecasts.

An equation for the Power Supply Margin calculation is represented below. The internal resources are adjusted to account for scheduled maintenance, inoperable units, forced outages, and hydro deratings. The demand is adjusted as previously described. The combination of all of the adjustments may seem overly conservative, but this helps to compensate for the optimistic nature of the SAM model.

Power Supply Margin = Zone Resources (adjusted) + Imports – Demand (adjusted) - Exports

Notable Changes since previous assessment

The determination of which planned resources to include was modified to better align with the NERC definitions for existing, under construction, planned and proposed resources. Class 1 resources remained defined as under construction with an in-service date prior to January 2012. Class 2 resources have received all regulatory approvals, have a signed interconnection agreement, and are expected to be in-service prior to January 2014. Class 3 resources are at least undergoing regulatory review and have completed at least a facility study. Class 3 resources must also be in active negotiations for an interconnection agreement with an in-service date prior to January 2014. Class 4 resources have met the NERC criteria for Planned

[21] Power Supply margin is the amount of resource capability (including imports) in excess of the demand requirements, after the specified adjustments to both demand and resources are applied.

resources, and Class 5 resources have met the NERC criteria for Proposed resources. Neither Class 4 nor Class 5 resources are included in any of the 2008 PSA studies.

Qualifications

The assessment model is designed to measure the Power Supply Margin based on forecasts of peak demands and seasonal resource capacity. While peak demand forecasts for several years into the future are readily available from the WECC control areas, the forecasts of resource additions are only accurate for a few years into the future. There is a point where the results shift from a determination of Power Supply Margin to a determination of future needs.

There is an ongoing concern regarding the potential retirement of several older generation plants, largely in California. Based on a traditional service life, numerous plants will be retiring over the time frame of this study; however, only the portion of these potential retirements that have been officially scheduled and reported to WECC are retired in the data used for this assessment. As more retirements are announced and reported, they will be represented in future assessments.

There is an important distinction between capacity and energy that must be considered, particularly for the Northwest sub-region. While a peak capacity study such as is reported here may show surplus capacity in the Northwest sub-region, the capacity may not be available for a multi-hour period due to the limited availability of water under most water conditions. Eventually WECC hopes to develop a methodology for preparing an energy assessment that would help to evaluate the impact of adverse water conditions on available capacity.

A determination that a zone has sufficient resources and imports to meet its load requirement does not necessarily mean that all of the demand centers within that zone can meet their load requirements. Transmission constraints internal to a zone may limit capacity transfers to local demand areas, leaving them without a positive margin. These transmission-constrained local demand areas may include one or more major metropolitan areas within a zone and may include most of the total population within a zone. WECC's seasonal assessments and Ten-Year Coordinated Plan Summaries address potential intra-zonal resource inadequacies based on information provided by representatives from the various areas.

Status of Recommended Enhancements from Previous PSA Reports

- Temperature based peak case – seasonal severe temperature based cases are modeled in Cases 6–11.
- Probabilistic studies –The LRS has not determined a time frame for adding probabilistic studies to the annual assessment.
- Energy assessment – The LRS postponed the question of an energy assessment while developing the building blocks for the planning reserve margin designed to evaluate summer peak demand conditions. It is the subject of future work.

B. Input Data and Parameters

The specific input data used in the assessment are presented in Tables 15–23, beginning on page 66. The tables list the base generation resources and show the derivation of the Power Supply Margin for each case.

Demands

Estimated monthly peak demands (firm and non-firm) for each SAM zone are included in the input data. These peak demands are derived from the peak demand forecasts that were submitted with the L&R data, and represent a 1–in–2 year probability forecast (50% probability of not being exceeded). The non-firm demands include interruptible and load management demands as reported with the L&R data. This assessment includes the non-firm demands for all cases.

Where Balancing Authorities spanned more than one zone, the demands were allocated by percentages (see details in Assumptions). The peak demands are aggregated by sub-region as presented in the summary tables in the results section.

Temperature Sensitivity

There is an expectation that the peak demand is directly correlated with the temperature(s) at the load centers. The applicable WECC members were requested to provide an indication of the approximate sensitivity (megawatts per degree Fahrenheit) of their peak demand to temperature variations. This data was used in this assessment to conduct a severe temperature case for both summer and winter.

Resources

The resource data include the existing generation units, the generation additions, the generation retirements, the scheduled maintenance, the inoperable generation, the forced outages, and miscellaneous deratings. As the diversity of generating technologies has increased, WECC has not developed standardized methods for determining resource capacity values for Balancing Authorities to use when submitting the L&R data. Each is left to devise and implement a method of its own choosing. The net resource capacities submitted through the L&R process were summarized by zone and type (hydro or non-hydro) before being copied into the model. The detailed generation data are available in the WECC publication *Existing Generation and Significant Additions and Changes to System Facilities 2006 – 2016*.

The summary tables in the results section provide details by sub-region for the generation capacities. Although the plans could change, generation retirements were considered by retirement date.

Scheduled maintenance and inoperable generation as reported in the L&R data were included as indicated in the studies. The majority of the July outages are scheduled for generation in the Canada sub-region. Other areas try to have all their units available for the summer peak. The generation owners in the summer peaking zones usually schedule their maintenance in the fall or spring.

Resource Adjustments - Hydro

In addition to the individual hydro generation capacities (seasonal median output) submitted with the L&R data, aggregate hydro capacities to reflect adverse water conditions are provided by the WECC Balancing Authorities. The differences in total capacity represent the adverse hydro capacity de-rates for each Balancing Authority.

The hydro generation unit capabilities submitted by the CAISO were generally nameplate capabilities. These were reduced to nominal levels in accordance with data provided by the CAISO.

The Northwest hydro was derated by approximately 5,200 MW in winter and 4,000 MW in summer, as submitted by the Balancing Authority respondents. This duration may not adequately capture the limitations on the ability of the Northwest hydro system to meet multi-hour peak loads.

The hydro generation unit capabilities submitted by the BC Hydro & Power Authority are mostly 3 hour dependable capacity in the peak load period of weekday during the continuous two weeks of cold weather (in winter). Therefore, no de-rate was applied.

Resource Adjustments – Non-hydro

The non-hydro generation includes thermal steam generation, carbon fuel combustion generation, geothermal generation, solar generation, wind generation, and others. The non-hydro generation capacities were de-rated as specified for selected cases.

Wind and Solar Capacity De-rates

Beginning with the 2006 Loads & Resource data request, the Balancing Authorities were asked to use a specific method when derating wind and solar generation. The method used a two step process and is intended to provide consistent reporting throughout the Western Interconnection. The process follows:

1. For each resource type, provide the 3 year average Installed Capability of all Wind, Solar PV, Solar Thermal and Solar Other generation within your control area at time of peak for each month. If 3 years of data are not available, use the average of the most recent 2 years or, the most recent year if only one year's data is available. If no actual data is available (such as for new plants), use the nameplate capacity. Use the appropriate resource code for each type reported.

2.

a. For each resource type, calculate the average of the actual portfolio production over the most recent 3 year period at time of control area peak demand for each month. If 3 years of data are not available, use the average of most recent 2 years or, the most recent year of production data, at time of control area peak demand. If no actual production data is available (such as for new plants), use the predicted production at time of control area peak demand.

b. Subtract the amount calculated in 2.a. from the amount in 1. and report the remaining amount as a NEGATIVE number for each month using the appropriate

resource code for each type. This number represents the capacity derate associated with each resource type.

Summer wind derates averaged approximately 84%, leaving a capacity value of approximately 16%, and winter wind derates averaged approximately 90%, leaving a capacity value of approximately 10%. The LRS examined a case with a capacity value of 0%, but the result, because of the low initial values and the limited saturation of wind machines in the existing base and in Class 1 and Classes 2 and 3, was not significantly different that the original cases. In the future, as more wind capacity is installed and as better information on the net effect of large, dispersed wind farms becomes available, this analysis will be improved.

Transfer Paths

The transfer paths used by the program are based on the SAM zones, with paths connecting one SAM zone to another SAM zone where applicable. The model has data fields for the path, transfer capability, wheeling cost, and loss factor. The wheeling costs for each path are used to calculate the transfer costs for any imports into a zone. The wheeling costs that were used were between $0 and $6.48. The loss factors are used to calculate the net transfer after losses for any imports into a zone. The loss factors were between 0% and 8%. Note that neither the wheeling cost nor the loss factors impeded the ability to import surplus resources to meet load.

The WECC Balancing Authorities were requested to provide the appropriate values to use for the restricted transfer capabilities between zones.

C. Results

The following attachments present additional results for the various cases, including tabular listings of the derivation of the annual Power Supply Margins by WECC sub-region. Note that the extent of the supply surplus or deficiency for a given sub-region is subject to the inherent problems associated with the simplistic methodology. If multiple zones are in need of additional capacity, several factors may determine which zone(s) get access to any surplus capacity. Additionally, the model solves to the least cost solution for the entire Western Interconnect, and not for the individual sub-regions. Therefore, if a bubble has excess capacity after balancing its supply and demand, the model will send that excess capacity to the bubble that produces the lowest cost for the entire interconnect, and not reserve that capacity for bubbles within the same sub-region. Generally, the model will make excess capacity available first to the deficit zone that is closest to the surplus zone because wheeling charges would typically be lower.

The results that are reported in this report are a measure of the amount of unused generation capacity (Power Supply Margin) in each of the defined sub-regions under the specified conditions. The input data for the individual zones included reported generation and demand values, but excluded the reported firm contracts with entities in other zones. The model calculates the transfers between the zones based on the solution criteria and the provided transfer capabilities. A negative Power Supply Margin for a zone or sub-region is indicative of resource shortages and/or transmission constraints. It is important to note that when the Power Supply Margin for a sub-region is zero (0), the sub-region is in resource/demand balance, and it may be importing to meet its demand. At the point where the Power Supply

Margin becomes negative, transmission constraints are preventing the sub-region from importing additional capacity.

D. Reserve Margin

Reserve Margin is a measure of the resource capability in excess of demand requirement. The industry commonly refers to two kinds of reserve margin, namely, operating reserve margin for day to day operations, and planning reserve margin for short or long term planning purposes. A planning reserve margin is generally higher than an operating reserve margin since it must account for all of the uncertainties. A planning reserve margin includes the margin for an operating reserve margin plus an additional margin for planning purposes.

The Minimum Operating Reliability Criteria Work Group (MORCWG) of WECC has defined an operating reserve requirement (operating reserve margin or contingency reserve) that requires a control area to maintain sufficient operating reserve as quoted below from the WECC Standard BAL-STD-002-WECC-1 – Contingency Reserves. It should be noted that, while this Standard has been approved by the WECC Board and submitted for final approval by both NERC and FERC, it is not effective at this time. The LRS has elected to use the 6% operating reserve as proposed in the new Standard when constructing the Building Block Guideline for the 2008 PSA.

R1. Each Reserve Sharing Group or Balancing Authority that is not a member of a Reserve Sharing Group shall maintain as a minimum Contingency Reserve that is the sum of the following:

R1.1. The greater of the following:

R1.1.1. An amount of reserve equal to the loss of the most severe single contingency; or

R1.1.2. An amount of reserve equal to the sum of three percent of the load (generation minus station service minus Net Actual Interchange) and three percent of net generation (generation minus station service).

R1.2. If the Source Balancing Authority designates an Interchange Transaction(s) as part of its Non-Spinning Contingency Reserve, the Sink Balancing Authority shall carry an amount of additional Non-Spinning Contingency Reserve equal to the Interchange Transaction(s). This type of transaction cannot be designated as Spinning Reserves by the source BA. If the Source Balancing Authority does not designate the Interchange Transaction as part of its Contingency Reserve, the Sink Balancing Authority is not required to carry any additional Contingency Reserves under this Requirement.

R1.3. If the Sink Balancing Authority is designating an Interchange Transaction(s) as part of its Contingency Reserve either Spinning or Non-Spinning, the Source Balancing Authority shall increase its Contingency Reserves equal in amount and type, to the

capacity transaction(s) where the Sink Balancing Authority is designating the transaction(s) as a resource to meet its Contingency Reserve requirements. These types of transactions could be designated as either spinning or non-spinning reserves. If designated as Spinning Reserves, all of the requirements of section R2.1 & R2.2 must be met.

R2. Each Reserve Sharing Group or Balancing Authority that is not a member of a Reserve Sharing Group shall maintain at least half of the Contingency Reserve in R1.1 as Spinning Reserve. Any Spinning Reserve specified in R1 shall meet the following requirements.

R2.1. Immediately and automatically responds proportionally to frequency deviations, e.g. through the action of a governor or other control systems.

R2.2. Capable of fully responding within ten minutes.

R3. Each Reserve Sharing Group or Balancing Authority shall use the following acceptable types of reserve which must be fully deployable within 10 minutes of notification to meet R1:

R3.1. Spinning Reserve;

R3.2. Interruptible Load;

R3.3. Interchange Transactions designated by the source Balancing Authority as non-spinning contingency reserve;

R3.4. Reserve held by other entities by agreement that is deliverable on Firm Transmission Service;

R3.5. An amount of off-line generation which can be synchronized and generating; or

R3.6. Load, other than Interruptible Load, once the Reliability Coordinator has declared a capacity or energy emergency.

WECC does not currently have a planning reserve margin requirement. However, the Power Supply Assessment Policy (see Attachment 4) defines a requirement to "project whether enough physical resources exist, at any price, to meet load and possible reserves while considering the transmission transfer capabilities of major paths." The Building Blocks reserve margin developed by LRS and approved by PCC is a means to meet that requirement.

Table 15 - Sub-region Resources - Class 1 Parameters (Summer Rating)

Parameter	Sub-region	2009	2010	2011	2012	2013	2014	2015	2016	2017
Existing Generation (Derated) (in-service on 12/31/07)	Canada	24,945	24,945	24,945	24,945	24,945	24,945	24,945	24,945	24,945
	Northwest	47,112	47,116	47,124	47,130	47,130	47,155	47,180	47,205	47,205
	Basin	12,811	12,811	12,811	12,811	12,811	12,811	12,811	12,811	12,811
	Rockies	17,189	17,189	17,189	17,189	17,189	17,189	17,189	17,189	17,189
	Desert SW	40,005	40,005	40,005	40,005	40,005	40,005	40,005	40,005	40,005
	No. CA	31,118	31,118	31,118	31,118	31,118	31,118	31,118	31,118	31,118
	So. CA/MX	31,481	31,481	31,481	31,481	31,481	31,481	31,481	31,481	31,481
	Total	204,661	204,665	204,673	204,679	204,679	204,704	204,729	204,754	204,754
Existing Hydro (Derated) Generation	Canada	12,064	12,064	12,064	12,064	12,064	12,064	12,064	12,064	12,064
	Northwest	33,385	33,389	33,397	33,403	33,403	33,428	33,453	33,478	33,478
	Basin	2,556	2,556	2,556	2,556	2,556	2,556	2,556	2,556	2,556
	Rockies	1,904	1,904	1,904	1,904	1,904	1,904	1,904	1,904	1,904
	Desert SW	3,581	3,581	3,581	3,581	3,581	3,581	3,581	3,581	3,581
	No. CA	9,844	9,844	9,844	9,844	9,844	9,844	9,844	9,844	9,844
	So. CA/MX	3,065	3,065	3,065	3,065	3,065	3,065	3,065	3,065	3,065
	Total	66,399	66,403	66,411	66,417	66,417	66,442	66,467	66,492	66,492
Existing NonHydro (Derated) Generation	Canada	12,881	12,881	12,881	12,881	12,881	12,881	12,881	12,881	12,881
	Northwest	13,727	13,727	13,727	13,727	13,727	13,727	13,727	13,727	13,727
	Basin	10,255	10,255	10,255	10,255	10,255	10,255	10,255	10,255	10,255
	Rockies	15,285	15,285	15,285	15,285	15,285	15,285	15,285	15,285	15,285
	Desert SW	36,424	36,424	36,424	36,424	36,424	36,424	36,424	36,424	36,424
	No. CA	21,274	21,274	21,274	21,274	21,274	21,274	21,274	21,274	21,274
	So. CA/MX	28,416	28,416	28,416	28,416	28,416	28,416	28,416	28,416	28,416
	Total	138,262	138,262	138,262	138,262	138,262	138,262	138,262	138,262	138,262
Net Class 1 Additions/Retirements (cutoff is study month)	Canada	40	272	231	-106	0	0	0	0	0
	Northwest	1	-6	0	0	0	0	0	0	0
	Basin	0	12	0	0	0	0	0	0	0
	Rockies	0	750	0	0	0	0	0	0	0
	Desert SW	206	400	484	0	0	0	0	0	0
	No. CA	401	44	0	0	0	0	0	0	0
	So. CA/MX	291	127	103	0	0	0	0	0	0
	Total	939	1,599	818	-106	0	0	0	0	0
Cumulative Committed Additions/Retirements	Canada	40	312	543	437	437	437	437	437	437
	Northwest	1	-5	-5	-5	-5	-5	-5	-5	-5
	Basin	0	11	11	11	11	11	11	11	11
	Rockies	0	750	750	750	750	750	750	750	750
	Desert SW	206	606	1,090	1,090	1,090	1,090	1,090	1,090	1,090
	No. CA	401	445	445	445	445	445	445	445	445
	So. CA/MX	291	418	521	521	521	521	521	521	521
	Total	939	2,537	3,355	3,249	3,249	3,249	3,249	3,249	3,249
Adverse Hydro Derates	Canada	-115	-115	-115	-115	-115	-115	-115	-115	-115
	Northwest	-3892	-3892	-3892	-3892	-3892	-3892	-3892	-3892	-3892
	Basin	-418	-418	-418	-418	-418	-418	-418	-418	-418
	Rockies	-129	-129	-129	-129	-129	-129	-129	-129	-129
	Desert SW	-57	-57	-57	-57	-57	-57	-57	-57	-57
	No. CA	-489	-489	-488	-488	-488	-488	-488	-488	-489
	So. CA/MX	-162	-162	-139	-137	-137	-137	-137	-137	-137
	Total	-5,262	-5,262	-5,238	-5,236	-5,236	-5,236	-5,236	-5,236	-5,237
Other Fixed Adjustments	Canada									
	Northwest									
	Basin									
	Rockies									
	Desert SW	325	325	325	325	325	325	325	325	325
	No. CA									
	So. CA/MX									
	Total	325	325	325	325	325	325	325	325	325
Net Base Resource Capacity	Canada	24,870	25,142	25,373	25,267	25,267	25,267	25,267	25,267	25,267
	Northwest	43,221	43,219	43,227	43,233	43,233	43,258	43,283	43,308	43,308
	Basin	12,393	12,404	12,404	12,404	12,404	12,404	12,404	12,404	12,404
	Rockies	17,060	17,810	17,810	17,810	17,810	17,810	17,810	17,810	17,810
	Desert SW	40,479	40,879	41,363	41,363	41,363	41,363	41,363	41,363	41,363
	No. CA	31,030	31,074	31,075	31,075	31,075	31,075	31,075	31,075	31,074
	So. CA/MX	31,610	31,737	31,863	31,865	31,865	31,865	31,865	31,865	31,865
	Total	200,663	202,265	203,115	203,017	203,017	203,042	203,067	203,092	203,091

Table 16 - Sub-region Resources - Class 1, 2 & 3 Parameters (Summer Rating)

Parameter	Sub-region	2009	2010	2011	2012	2013	2014	2015	2016	2017
Existing Generation (Derated) (in-service on 12/31/07)	Canada	24,945	24,945	24,945	24,945	24,945	24,945	24,945	24,945	24,945
	Northwest	47,105	47,101	47,101	47,100	47,100	47,125	47,150	47,175	47,175
	Basin	12,811	12,811	12,811	12,811	12,811	12,811	12,811	12,811	12,811
	Rockies	17,189	17,189	17,189	17,189	17,189	17,189	17,189	17,189	17,189
	Desert SW	40,005	40,005	40,005	40,005	40,005	40,005	40,005	40,005	40,005
	No. CA	31,118	31,118	31,118	31,118	31,118	31,118	31,118	31,118	31,118
	So. CA/MX	31,481	31,481	31,481	31,481	31,481	31,481	31,481	31,481	31,481
	Total	204,654	204,650	204,650	204,649	204,649	204,674	204,699	204,724	204,724
Existing Hydro (Derated) Generation	Canada	12,064	12,064	12,064	12,064	12,064	12,064	12,064	12,064	12,064
	Northwest	33,378	33,374	33,374	33,373	33,373	33,398	33,423	33,448	33,448
	Basin	2,556	2,556	2,556	2,556	2,556	2,556	2,556	2,556	2,556
	Rockies	1,904	1,904	1,904	1,904	1,904	1,904	1,904	1,904	1,904
	Desert SW	3,581	3,581	3,581	3,581	3,581	3,581	3,581	3,581	3,581
	No. CA	9,844	9,844	9,844	9,844	9,844	9,844	9,844	9,844	9,844
	So. CA/MX	3,065	3,065	3,065	3,065	3,065	3,065	3,065	3,065	3,065
	Total	66,392	66,388	66,388	66,387	66,387	66,412	66,437	66,462	66,462
Existing NonHydro (Derated) Generation	Canada	12,881	12,881	12,881	12,881	12,881	12,881	12,881	12,881	12,881
	Northwest	13,727	13,727	13,727	13,727	13,727	13,727	13,727	13,727	13,727
	Basin	10,255	10,255	10,255	10,255	10,255	10,255	10,255	10,255	10,255
	Rockies	15,285	15,285	15,285	15,285	15,285	15,285	15,285	15,285	15,285
	Desert SW	36,424	36,424	36,424	36,424	36,424	36,424	36,424	36,424	36,424
	No. CA	21,274	21,274	21,274	21,274	21,274	21,274	21,274	21,274	21,274
	So. CA/MX	28,416	28,416	28,416	28,416	28,416	28,416	28,416	28,416	28,416
	Total	138,262	138,262	138,262	138,262	138,262	138,262	138,262	138,262	138,262
Net Class 1, 2 & 3 Additions/Retirements (cutoff is study month)	Canada	77	436	1,166	-106	0	0	0	0	0
	Northwest	118	2	7	7	0	0	0	0	0
	Basin	17	104	47	61	0	0	0	0	0
	Rockies	33	773	515	44	730	0	0	-4	0
	Desert SW	238	446	484	262	0	0	0	0	0
	No. CA	524	44	0	0	0	0	0	0	0
	So. CA/MX	291	127	103	0	0	0	0	0	0
	Total	1,299	1,931	2,322	269	730	0	0	-4	0
Cumulative Committed Additions/Retirements	Canada	77	513	1,679	1,573	1,573	1,573	1,573	1,573	1,573
	Northwest	118	120	127	135	135	135	135	135	135
	Basin	17	122	168	229	229	229	229	229	229
	Rockies	33	806	1,320	1,365	2,094	2,094	2,094	2,091	2,091
	Desert SW	238	684	1,168	1,430	1,430	1,430	1,430	1,430	1,430
	No. CA	524	567	567	567	567	567	567	567	567
	So. CA/MX	291	418	521	521	521	521	521	521	521
	Total	1,299	3,230	5,552	5,821	6,550	6,550	6,550	6,547	6,547
Adverse Hydro Derates	Canada	-153	-115	-115	-115	-115	-115	-115	-115	-115
	Northwest	-3,892	-3,892	-3,892	-3,892	-3,892	-3,892	-3,892	-3,892	-3,892
	Basin	-418	-418	-418	-418	-418	-418	-418	-418	-418
	Rockies	-129	-129	-129	-129	-129	-129	-129	-129	-129
	Desert SW	-57	-57	-57	-57	-57	-57	-57	-57	-57
	No. CA	-489	-489	-488	-488	-488	-488	-488	-488	-489
	So. CA/MX	-162	-162	-139	-137	-137	-137	-137	-137	-137
	Total	-5,300	-5,262	-5,238	-5,236	-5,236	-5,236	-5,236	-5,236	-5,237
Other Fixed Adjustments	Canada									
	Northwest									
	Basin									
	Rockies									
	Desert SW	325	325	325	325	325	325	325	325	325
	No. CA									
	So. CA/MX									
	Total	325	325	325	325	325	325	325	325	325
Net Base Resource Capacity	Canada	24,869	25,343	26,509	26,403	26,403	26,403	26,403	26,403	26,403
	Northwest	43,331	43,329	43,336	43,343	43,343	43,368	43,393	43,418	43,418
	Basin	12,410	12,515	12,561	12,622	12,622	12,622	12,622	12,622	12,622
	Rockies	17,093	17,866	18,380	18,425	19,154	19,154	19,154	19,151	19,151
	Desert SW	40,511	40,957	41,441	41,703	41,703	41,703	41,703	41,703	41,703
	No. CA	31,153	31,196	31,197	31,197	31,197	31,197	31,197	31,197	31,196
	So. CA/MX	31,610	31,737	31,863	31,865	31,865	31,865	31,865	31,865	31,865
	Total	200,978	202,943	205,289	205,559	206,288	206,313	206,338	206,360	206,359

Table 17 - Sub-region Resources - Class 1 Parameters (Winter Rating)

Parameter	Sub-region	2009	2010	2011	2012	2013	2014	2015	2016	2017
Existing Generation (Derated) (in-service on 12/31/07)	Canada	24,050	24,050	24,050	24,050	24,050	24,050	24,050	24,050	24,050
	Northwest	46,895	46,910	46,917	46,923	46,948	46,973	46,998	46,997	46,997
	Basin	12,602	12,602	12,602	12,602	12,602	12,602	12,602	12,602	12,602
	Rockies	17,506	17,506	17,506	17,506	17,506	17,506	17,506	17,506	17,506
	Desert SW	41,031	41,031	41,031	41,031	41,031	41,031	41,031	41,031	41,031
	No. CA	31,018	31,018	31,018	31,018	31,018	31,018	31,018	31,018	31,018
	So. CA/MX	31,278	31,278	31,278	31,278	31,278	31,278	31,278	31,278	31,278
	Total	204,380	204,395	204,402	204,408	204,433	204,458	204,483	204,482	204,482
Existing Hydro (Derated) Generation	Canada	11,140	11,140	11,140	11,140	11,140	11,140	11,140	11,140	11,140
	Northwest	32,931	32,946	32,953	32,959	32,984	33,009	33,034	33,033	33,033
	Basin	2,146	2,146	2,146	2,146	2,146	2,146	2,146	2,146	2,146
	Rockies	1,773	1,773	1,773	1,773	1,773	1,773	1,773	1,773	1,773
	Desert SW	3,512	3,512	3,512	3,512	3,512	3,512	3,512	3,512	3,512
	No. CA	9,849	9,849	9,849	9,849	9,849	9,849	9,849	9,849	9,849
	So. CA/MX	3,065	3,065	3,065	3,065	3,065	3,065	3,065	3,065	3,065
	Total	64,416	64,431	64,438	64,444	64,469	64,494	64,519	64,518	64,518
Existing NonHydro (Derated) Generation	Canada	12,910	12,910	12,910	12,910	12,910	12,910	12,910	12,910	12,910
	Northwest	13,964	13,964	13,964	13,964	13,964	13,964	13,964	13,964	13,964
	Basin	10,456	10,456	10,456	10,456	10,456	10,456	10,456	10,456	10,456
	Rockies	15,733	15,733	15,733	15,733	15,733	15,733	15,733	15,733	15,733
	Desert SW	37,519	37,519	37,519	37,519	37,519	37,519	37,519	37,519	37,519
	No. CA	21,169	21,169	21,169	21,169	21,169	21,169	21,169	21,169	21,169
	So. CA/MX	28,213	28,213	28,213	28,213	28,213	28,213	28,213	28,213	28,213
	Total	139,964	139,964	139,964	139,964	139,964	139,964	139,964	139,964	139,964
Net Class 1 Additions/Retirements (cutoff is study month)	Canada	105	-101	344	0	0	0	0	0	0
	Northwest	0	-6	0	0	0	0	0	0	0
	Basin	30	0	0	0	0	0	0	0	0
	Rockies	0	750	0	0	0	0	0	0	0
	Desert SW	607	0	484	0	0	0	0	0	0
	No. CA	401	47	0	0	0	0	0	0	0
	So. CA/MX	292	127	103	0	0	0	0	0	0
	Total	1,436	817	931	0	0	0	0	0	0
Cumulative Committed Additions/Retirements	Canada	105	4	348	348	348	348	348	348	348
	Northwest	0	-6	-6	-6	-6	-6	-6	-6	-6
	Basin	30	30	30	30	30	30	30	30	30
	Rockies	0	750	750	750	750	750	750	750	750
	Desert SW	607	607	1,091	1,091	1,091	1,091	1,091	1,091	1,091
	No. CA	401	448	448	448	448	448	448	448	448
	So. CA/MX	292	419	522	522	522	522	522	522	522
	Total	1,436	2,253	3,184	3,184	3,184	3,184	3,184	3,184	3,184
Adverse Hydro Derates	Canada	0	0	0	0	0	0	0	0	0
	Northwest	-5,068	-5,068	-5,068	-5,068	-5,068	-5,068	-5,068	-5,068	-5,068
	Basin	-413	-413	-413	-413	-413	-413	-413	-413	-413
	Rockies	-148	-148	-148	-148	-148	-148	-148	-148	-148
	Desert SW	-69	-69	-69	-69	-69	-69	-69	-69	-69
	No. CA	-502	-501	-501	-501	-501	-501	-501	-501	-501
	So. CA/MX	-169	-165	-145	-144	-144	-144	-144	-144	-144
	Total	-6,369	-6,364	-6,344	-6,343	-6,343	-6,343	-6,343	-6,343	-6,343
Other Fixed Adjustments	Canada									
	Northwest									
	Basin									
	Rockies									
	Desert SW	325	325	325	325	325	325	325	325	325
	No. CA									
	So. CA/MX									
	Total	325	325	325	325	325	325	325	325	325
Net Base Resource Capacity	Canada	24,155	24,054	24,398	24,398	24,398	24,398	24,398	24,398	24,398
	Northwest	41,827	41,836	41,843	41,849	41,874	41,899	41,924	41,923	41,923
	Basin	12,219	12,219	12,219	12,219	12,219	12,219	12,219	12,219	12,219
	Rockies	17,358	18,108	18,108	18,108	18,108	18,108	18,108	18,108	18,108
	Desert SW	41,894	41,894	42,378	42,378	42,378	42,378	42,378	42,378	42,378
	No. CA	30,917	30,965	30,965	30,965	30,965	30,965	30,965	30,965	30,965
	So. CA/MX	31,401	31,532	31,655	31,656	31,656	31,656	31,656	31,656	31,656
	Total	199,772	200,609	201,567	201,574	201,599	201,624	201,649	201,648	201,648

Table 18 - Sub-region Resources - Class 1, 2 & 3 Parameters (Winter Rating)

Parameter	Sub-region	2009	2010	2011	2012	2013	2014	2015	2016	2017
Existing Generation (Derated) (in-service on 12/31/07)	Canada	24,050	24,050	24,050	24,050	24,050	24,050	24,050	24,050	24,050
	Northwest	46,895	46,910	46,917	46,923	46,948	46,973	46,998	46,997	46,997
	Basin	12,602	12,602	12,602	12,602	12,602	12,602	12,602	12,602	12,602
	Rockies	17,506	17,506	17,506	17,506	17,506	17,506	17,506	17,506	17,506
	Desert SW	41,031	41,031	41,031	41,031	41,031	41,031	41,031	41,031	41,031
	No. CA	31,018	31,018	31,018	31,018	31,018	31,018	31,018	31,018	31,018
	So. CA/MX	31,278	31,278	31,278	31,278	31,278	31,278	31,278	31,278	31,278
	Total	204,380	204,395	204,402	204,408	204,433	204,458	204,483	204,482	204,482
Existing Hydro (Derated) Generation	Canada	11,140	11,140	11,140	11,140	11,140	11,140	11,140	11,140	11,140
	Northwest	32,931	32,946	32,953	32,959	32,984	33,009	33,034	33,033	33,033
	Basin	2,146	2,146	2,146	2,146	2,146	2,146	2,146	2,146	2,146
	Rockies	1,773	1,773	1,773	1,773	1,773	1,773	1,773	1,773	1,773
	Desert SW	3,512	3,512	3,512	3,512	3,512	3,512	3,512	3,512	3,512
	No. CA	9,849	9,849	9,849	9,849	9,849	9,849	9,849	9,849	9,849
	So. CA/MX	3,065	3,065	3,065	3,065	3,065	3,065	3,065	3,065	3,065
	Total	64,416	64,431	64,438	64,444	64,469	64,494	64,519	64,518	64,518
Existing NonHydro (Derated) Generation	Canada	12,910	12,910	12,910	12,910	12,910	12,910	12,910	12,910	12,910
	Northwest	13,964	13,964	13,964	13,964	13,964	13,964	13,964	13,964	13,964
	Basin	10,456	10,456	10,456	10,456	10,456	10,456	10,456	10,456	10,456
	Rockies	15,733	15,733	15,733	15,733	15,733	15,733	15,733	15,733	15,733
	Desert SW	37,519	37,519	37,519	37,519	37,519	37,519	37,519	37,519	37,519
	No. CA	21,169	21,169	21,169	21,169	21,169	21,169	21,169	21,169	21,169
	So. CA/MX	28,213	28,213	28,213	28,213	28,213	28,213	28,213	28,213	28,213
	Total	139,964	139,964	139,964	139,964	139,964	139,964	139,964	139,964	139,964
Net Class 1, 2 & 3 Additions/Retirements (cutoff is study month)	Canada	231	459	779	0	0	0	0	0	0
	Northwest	118	1	7	7	0	0	0	0	0
	Basin	78	85	79	45	0	0	0	0	0
	Rockies	37	871	420	44	726	0	0	0	0
	Desert SW	639	46	484	-18	0	0	0	0	0
	No. CA	524	47	0	0	0	0	0	0	0
	So. CA/MX	292	127	103	0	0	0	0	0	0
	Total	1,918	1,636	1,873	79	726	0	0	0	0
Cumulative Committed Additions/Retirements	Canada	231	690	1,469	1,469	1,469	1,469	1,469	1,469	1,469
	Northwest	118	119	127	134	134	134	134	134	134
	Basin	78	163	242	287	287	287	287	287	287
	Rockies	37	908	1,328	1,372	2,098	2,098	2,098	2,098	2,098
	Desert SW	639	685	1,169	1,151	1,151	1,151	1,151	1,151	1,151
	No. CA	524	571	571	571	571	571	571	571	571
	So. CA/MX	292	419	522	522	522	522	522	522	522
	Total	1,918	3,555	5,427	5,506	6,232	6,232	6,232	6,232	6,232
Adverse Hydro Derates	Canada	0	0	0	0	0	0	0	0	0
	Northwest	-5,073	-5,084	-5,091	-5,097	-5,097	-5,097	-5,097	-5,097	-5,097
	Basin	-413	-413	-413	-413	-413	-413	-413	-413	-413
	Rockies	-148	-148	-148	-148	-148	-148	-148	-148	-148
	Desert SW	-69	-69	-69	-69	-69	-69	-69	-69	-69
	No. CA	-502	-501	-501	-501	-501	-501	-501	-501	-501
	So. CA/MX	-169	-165	-145	-144	-144	-144	-144	-144	-144
	Total	-6,374	-6,380	-6,367	-6,372	-6,372	-6,372	-6,372	-6,372	-6,372
Other Fixed Adjustments	Canada									
	Northwest									
	Basin									
	Rockies									
	Desert SW	325	325	325	325	325	325	325	325	325
	No. CA									
	So. CA/MX									
	Total	325	325	325	325	325	325	325	325	325
Net Base Resource Capacity	Canada	24,281	24,740	25,519	25,519	25,519	25,519	25,519	25,519	25,519
	Northwest	41,940	41,945	41,953	41,960	41,985	42,010	42,035	42,034	42,034
	Basin	12,267	12,352	12,431	12,476	12,476	12,476	12,476	12,476	12,476
	Rockies	17,395	18,266	18,686	18,730	19,456	19,456	19,456	19,456	19,456
	Desert SW	41,926	41,972	42,456	42,438	42,438	42,438	42,438	42,438	42,438
	No. CA	31,040	31,088	31,088	31,088	31,088	31,088	31,088	31,088	31,088
	So. CA/MX	31,401	31,532	31,655	31,656	31,656	31,656	31,656	31,656	31,656
	Total	200,249	201,895	203,787	203,867	204,618	204,643	204,668	204,667	204,667

Table 19 - Sub-region Summary - Case #1

Parameter	Sub-region	2009	2010	2011	2012	2013	2014	2015	2016	2017
Firm Demand	Canada	18,418	18,844	19,380	19,872	20,398	20,800	21,298	21,742	22,271
	Northwest	25,201	25,584	25,914	26,383	26,775	27,178	27,547	27,924	28,285
	Basin	12,379	12,674	12,950	13,333	13,627	13,896	14,181	14,530	14,736
	Rockies	13,465	13,670	13,983	14,335	14,697	15,040	15,407	15,827	16,210
	Desert SW	32,001	32,899	33,870	34,802	35,675	36,627	37,583	38,486	39,442
	No. CA	26,106	26,486	26,879	27,260	27,639	28,009	28,387	28,745	29,092
	So. CA/MX	34,122	34,668	35,234	35,793	36,346	36,908	37,470	38,038	38,596
	Total	161,692	164,825	168,210	171,778	175,157	178,458	181,873	185,292	188,632
Non-Firm Demand	Canada	0	0	0	0	0	0	0	0	0
	Northwest	0	6	10	30	30	30	30	30	30
	Basin	297	297	297	302	302	302	302	302	302
	Rockies	354	408	446	462	477	480	472	462	453
	Desert SW	619	677	700	693	707	718	743	752	762
	No. CA	1,484	1,507	1,529	1,551	1,571	1,590	1,611	1,630	1,648
	So. CA/MX	1,523	1,546	1,569	1,592	1,615	1,637	1,659	1,681	1,703
	Total	4,277	4,441	4,551	4,630	4,702	4,757	4,817	4,857	4,898
Building Block Reserve Requirement	Canada	2,082	2,130	2,191	2,247	2,306	2,351	2,408	2,458	2,518
	Northwest	3,595	3,649	3,696	3,763	3,819	3,877	3,929	3,983	4,035
	Basin	1,506	1,542	1,575	1,622	1,658	1,690	1,725	1,767	1,793
	Rockies	1,584	1,608	1,645	1,686	1,729	1,769	1,813	1,862	1,907
	Desert SW	4,247	4,366	4,495	4,618	4,734	4,861	4,988	5,107	5,234
	No. CA	4,043	4,101	4,162	4,221	4,280	4,337	4,395	4,451	4,504
	So. CA/MX	5,558	5,645	5,735	5,824	5,912	6,002	6,091	6,181	6,269
	Total	22,614	23,042	23,500	23,982	24,439	24,887	25,348	25,810	26,260
Load Requirement	Canada	20,500	20,974	21,571	22,119	22,704	23,151	23,706	24,200	24,789
	Northwest	28,796	29,239	29,620	30,176	30,624	31,085	31,506	31,937	32,350
	Basin	14,182	14,513	14,822	15,257	15,587	15,888	16,208	16,599	16,831
	Rockies	15,403	15,686	16,074	16,483	16,903	17,289	17,692	18,151	18,570
	Desert SW	36,867	37,942	39,065	40,113	41,116	42,206	43,314	44,345	45,438
	No. CA	31,633	32,094	32,570	33,032	33,490	33,936	34,393	34,826	35,244
	So. CA/MX	41,203	41,859	42,538	43,209	43,873	44,547	45,220	45,900	46,568
	Total	188,583	192,308	196,261	200,390	204,298	208,102	212,038	215,959	219,790
Net Base Resource Capacity	Canada	24,870	25,142	25,373	25,267	25,267	25,267	25,267	25,267	25,267
	Northwest	43,221	43,219	43,227	43,233	43,233	43,258	43,283	43,308	43,308
	Basin	12,393	12,404	12,404	12,404	12,404	12,404	12,404	12,404	12,404
	Rockies	17,060	17,810	17,810	17,810	17,810	17,810	17,810	17,810	17,810
	Desert SW	40,479	40,879	41,363	41,363	41,363	41,363	41,363	41,363	41,363
	No. CA	31,030	31,074	31,075	31,075	31,075	31,075	31,075	31,075	31,074
	So. CA/MX	31,610	31,737	31,863	31,865	31,865	31,865	31,865	31,865	31,865
	Total	200,663	202,265	203,115	203,017	203,017	203,042	203,067	203,092	203,091
Other Outages and Line Losses	Canada	-1,877	-1,888	-1,894	-1,897	-1,897	-1,896	-1,897	-1,897	-1,896
	Northwest	-723	-712	-664	-662	-650	-646	-713	-700	-677
	Basin	-203	-203	-204	-197	-193	-191	-183	-178	-183
	Rockies	-72	-62	-57	-52	-49	-49	-46	-45	-45
	Desert SW	-188	-171	-153	-149	-150	-149	-149	-149	-149
	No. CA	-206	-209	-206	-210	-210	-206	-205	-204	-203
	So. CA/MX	-611	-606	-592	-585	-577	-576	-573	-571	-571
	Total	-3,879	-3,851	-3,770	-3,752	-3,725	-3,714	-3,766	-3,743	-3,723
SAM Net Imports (+) (negative if exporting)	Canada	-1,145	-905	-493	-254	-133	-90	0	0	0
	Northwest	-7,180	-7,420	-7,831	-8,071	-8,192	-8,235	-8,325	-8,325	-8,325
	Basin	1,992	2,312	2,537	2,437	2,437	2,437	2,437	2,437	2,441
	Rockies	-1,585	-2,062	-2,024	-2,024	-2,024	-2,024	-2,024	-2,024	-2,024
	Desert SW	-3,094	-3,744	-4,314	-4,432	-4,386	-4,338	-4,289	-4,236	-4,183
	No. CA	809	1,230	1,702	2,168	2,480	2,532	2,585	2,637	2,683
	So. CA/MX	10,203	10,590	10,425	10,177	9,818	9,718	9,616	9,511	9,407
	Total	0	0	0	0	0	0	0	0	0
Available Resources including Transfers	Canada	21,848	22,349	22,985	23,116	23,237	23,280	23,370	23,370	23,371
	Northwest	35,317	35,087	34,732	34,500	34,391	34,377	34,245	34,283	34,306
	Basin	14,182	14,513	14,737	14,644	14,648	14,650	14,658	14,663	14,663
	Rockies	15,403	15,686	15,729	15,734	15,737	15,737	15,740	15,741	15,741
	Desert SW	37,198	36,964	36,896	36,783	36,828	36,876	36,926	36,979	37,032
	No. CA	31,633	32,094	32,570	33,032	33,345	33,401	33,455	33,508	33,553
	So. CA/MX	41,203	41,721	41,696	41,457	41,106	41,007	40,909	40,806	40,702
	Total	196,783	198,415	199,345	199,265	199,292	199,328	199,302	199,349	199,368
Power Supply Margin	Canada	1,348	1,375	1,414	997	533	129	-336	-830	-1,418
	Northwest	6,521	5,848	5,111	4,324	3,767	3,292	2,739	2,346	1,957
	Basin	0	0	-86	-613	-939	-1,238	-1,550	-1,936	-2,168
	Rockies	0	0	-345	-750	-1,166	-1,553	-1,952	-2,410	-2,829
	Desert SW	331	-978	-2,169	-3,331	-4,289	-5,330	-6,388	-7,367	-8,407
	No. CA	0	0	0	0	-145	-535	-938	-1,318	-1,691
	So. CA/MX	0	-138	-842	-1,753	-2,767	-3,539	-4,311	-5,094	-5,866
	Total	8,201	6,107	3,084	-1,125	-5,006	-8,774	-12,737	-16,609	-20,421

Table 20 - Sub-region Summary - Case #2

Parameter	Sub-region	2009	2010	2011	2012	2013	2014	2015	2016	2017
Firm Demand	Canada	22,336	22,903	23,532	24,104	24,710	25,173	25,682	26,193	26,796
	Northwest	30,116	30,452	30,846	31,242	31,614	31,977	32,362	32,724	33,159
	Basin	10,336	10,579	10,695	11,024	11,223	11,455	11,657	11,898	12,051
	Rockies	11,626	11,813	12,058	12,364	12,635	12,929	13,223	13,526	13,867
	Desert SW	20,036	20,575	21,127	21,709	22,223	22,801	23,389	23,938	24,525
	No. CA	19,286	19,575	19,882	20,177	20,470	20,758	21,032	21,287	21,552
	So. CA/MX	25,939	26,341	26,758	27,171	27,581	27,993	28,408	28,826	29,228
	Total	139,675	142,238	144,898	147,791	150,456	153,086	155,753	158,392	161,178
Non-Firm Demand	Canada	0	0	0	0	0	0	0	0	0
	Northwest	0	0	0	0	0	0	0	0	0
	Basin	213	213	213	213	213	213	213	213	213
	Rockies	206	241	263	267	272	273	275	276	277
	Desert SW	647	641	658	645	653	658	677	680	684
	No. CA	985	1,000	1,014	1,028	1,042	1,056	1,070	1,083	1,097
	So. CA/MX	1,153	1,170	1,188	1,206	1,223	1,239	1,256	1,273	1,289
	Total	3,204	3,265	3,336	3,359	3,403	3,439	3,491	3,525	3,560
Building Block Reserve Requirement	Canada	2,957	3,032	3,116	3,191	3,272	3,333	3,400	3,468	3,548
	Northwest	4,767	4,821	4,883	4,946	5,005	5,062	5,123	5,180	5,249
	Basin	1,208	1,237	1,251	1,289	1,312	1,339	1,363	1,391	1,409
	Rockies	1,554	1,579	1,611	1,652	1,688	1,728	1,767	1,808	1,853
	Desert SW	2,559	2,627	2,698	2,772	2,838	2,912	2,987	3,057	3,132
	No. CA	2,135	2,167	2,200	2,233	2,266	2,297	2,328	2,356	2,385
	So. CA/MX	3,073	3,119	3,168	3,216	3,263	3,311	3,359	3,407	3,454
	Total	18,253	18,582	18,927	19,299	19,643	19,982	20,327	20,667	21,030
Load Requirement	Canada	25,293	25,935	26,648	27,295	27,982	28,506	29,082	29,661	30,344
	Northwest	34,883	35,273	35,729	36,188	36,619	37,039	37,485	37,904	38,408
	Basin	11,757	12,029	12,159	12,526	12,748	13,007	13,233	13,502	13,673
	Rockies	13,386	13,633	13,932	14,283	14,595	14,930	15,265	15,610	15,997
	Desert SW	23,242	23,843	24,483	25,126	25,714	26,371	27,053	27,675	28,341
	No. CA	22,406	22,742	23,096	23,438	23,778	24,111	24,430	24,726	25,034
	So. CA/MX	30,165	30,630	31,114	31,593	32,067	32,543	33,023	33,506	33,971
	Total	161,132	164,085	167,161	170,449	173,502	176,507	179,571	182,584	185,768
Net Base Resource Capacity	Canada	24,155	24,054	24,398	24,398	24,398	24,398	24,398	24,398	24,398
	Northwest	41,827	41,836	41,843	41,849	41,874	41,899	41,924	41,923	41,923
	Basin	12,219	12,219	12,219	12,219	12,219	12,219	12,219	12,219	12,219
	Rockies	17,358	18,108	18,108	18,108	18,108	18,108	18,108	18,108	18,108
	Desert SW	41,894	41,894	42,378	42,378	42,378	42,378	42,378	42,378	42,378
	No. CA	30,917	30,965	30,965	30,965	30,965	30,965	30,965	30,965	30,965
	So. CA/MX	31,401	31,532	31,655	31,656	31,656	31,656	31,656	31,656	31,656
	Total	199,772	200,609	201,567	201,574	201,599	201,624	201,649	201,648	201,648
Other Outages and Line Losses	Canada	-610	-611	-616	-620	-623	-622	-619	-615	-610
	Northwest	-229	-162	-166	-60	-46	-20	-123	-114	-115
	Basin	-125	-144	-151	-159	-165	-171	-174	-182	-185
	Rockies	-119	-121	-119	-115	-113	-119	-125	-127	-130
	Desert SW	-742	-742	-849	-556	-687	-1,188	-646	-1,208	-1,147
	No. CA	-923	-876	-875	-875	-878	-876	-876	-877	-876
	So. CA/MX	-1,607	-1,699	-1,839	-1,849	-1,854	-1,853	-1,850	-1,859	-1,865
	Total	-4,354	-4,356	-4,615	-4,233	-4,367	-4,850	-4,414	-4,983	-4,928
SAM Net Imports (+) (negative if exporting)	Canada	1,447	1,438	1,645	1,844	2,000	2,000	2,000	2,000	2,000
	Northwest	971	162	-45	-243	-400	-505	-724	-1,482	-1,677
	Basin	-337	-46	90	466	694	959	1,188	1,465	1,639
	Rockies	-2,731	-2,731	-2,731	-2,731	-2,731	-2,731	-2,718	-2,371	-1,982
	Desert SW	-2,563	-1,961	-1,748	-2,064	-2,461	-2,655	-2,655	-1,638	-1,057
	No. CA	38	-487	-1,460	-2,008	-2,319	-2,116	-1,830	-2,489	-2,669
	So. CA/MX	3,175	3,625	4,249	4,737	5,216	5,048	4,738	4,515	3,746
	Total	0	0	0	0	0	0	0	0	0
Available Resources including Transfers	Canada	24,992	24,881	25,428	25,622	25,775	25,777	25,780	25,784	25,788
	Northwest	42,570	41,836	41,633	41,546	41,428	41,374	41,077	40,327	40,131
	Basin	11,757	12,029	12,159	12,526	12,748	13,007	13,233	13,502	13,673
	Rockies	14,509	15,257	15,258	15,263	15,264	15,258	15,265	15,610	15,997
	Desert SW	38,589	39,190	39,781	39,758	39,230	38,535	39,077	39,532	40,174
	No. CA	30,032	29,602	28,631	28,082	27,769	27,973	28,260	27,599	27,420
	So. CA/MX	32,969	33,457	34,064	34,544	35,018	34,850	34,544	34,312	33,537
	Total	195,419	196,253	196,952	197,341	197,232	196,774	197,235	196,665	196,720
Power Supply Margin	Canada	-301	-1,054	-1,220	-1,673	-2,207	-2,729	-3,303	-3,877	-4,556
	Northwest	7,687	6,564	5,904	5,359	4,810	4,335	3,593	2,423	1,723
	Basin	0	0	0	0	0	0	0	0	0
	Rockies	1,123	1,624	1,326	979	669	328	0	0	0
	Desert SW	15,347	15,347	15,298	14,632	13,516	12,164	12,024	11,857	11,833
	No. CA	7,627	6,860	5,534	4,644	3,991	3,862	3,830	2,873	2,385
	So. CA/MX	2,804	2,827	2,950	2,951	2,951	2,307	1,521	806	-433
	Total	34,287	32,168	29,791	26,892	23,730	20,267	17,664	14,081	10,952

Table 21 - Sub-region Summary - Case #3

Parameter	Sub-region	2009	2010	2011	2012	2013	2014	2015	2016	2017
Firm Demand	Canada	18,418	18,844	19,380	19,872	20,398	20,800	21,298	21,742	22,271
	Northwest	25,201	25,584	25,914	26,383	26,775	27,178	27,547	27,924	28,285
	Basin	12,379	12,674	12,950	13,333	13,627	13,896	14,181	14,530	14,736
	Rockies	13,465	13,670	13,983	14,335	14,697	15,040	15,407	15,827	16,210
	Desert SW	32,001	32,899	33,870	34,802	35,675	36,627	37,583	38,486	39,442
	No. CA	26,106	26,486	26,879	27,260	27,639	28,009	28,387	28,745	29,092
	So. CA/MX	34,122	34,668	35,234	35,793	36,346	36,908	37,470	38,038	38,596
	Total	161,692	164,825	168,210	171,778	175,157	178,458	181,873	185,292	188,632
Non-Firm Demand	Canada	0	0	0	0	0	0	0	0	0
	Northwest	0	6	10	30	30	30	30	30	30
	Basin	297	297	297	302	302	302	302	302	302
	Rockies	354	408	446	462	477	480	472	462	453
	Desert SW	619	677	700	693	707	718	743	752	762
	No. CA	1,484	1,507	1,529	1,551	1,571	1,590	1,611	1,630	1,648
	So. CA/MX	1,523	1,546	1,569	1,592	1,615	1,637	1,659	1,681	1,703
	Total	4,277	4,441	4,551	4,630	4,702	4,757	4,817	4,857	4,898
Building Block Reserve Requirement	Canada	2,082	2,130	2,191	2,247	2,306	2,351	2,408	2,458	2,518
	Northwest	3,595	3,649	3,696	3,763	3,819	3,877	3,929	3,983	4,035
	Basin	1,506	1,542	1,575	1,622	1,658	1,690	1,725	1,767	1,793
	Rockies	1,584	1,608	1,645	1,686	1,729	1,769	1,813	1,862	1,907
	Desert SW	4,247	4,366	4,495	4,618	4,734	4,861	4,988	5,107	5,234
	No. CA	4,043	4,101	4,162	4,221	4,280	4,337	4,395	4,451	4,504
	So. CA/MX	5,558	5,645	5,735	5,824	5,912	6,002	6,091	6,181	6,269
	Total	22,614	23,042	23,500	23,982	24,439	24,887	25,348	25,810	26,260
Load Requirement	Canada	20,500	20,974	21,571	22,119	22,704	23,151	23,706	24,200	24,789
	Northwest	28,796	29,239	29,620	30,176	30,624	31,085	31,506	31,937	32,350
	Basin	14,182	14,513	14,822	15,257	15,587	15,888	16,208	16,599	16,831
	Rockies	15,403	15,686	16,074	16,483	16,903	17,289	17,692	18,151	18,570
	Desert SW	36,867	37,942	39,065	40,113	41,116	42,206	43,314	44,345	45,438
	No. CA	31,633	32,094	32,570	33,032	33,490	33,936	34,393	34,826	35,244
	So. CA/MX	41,203	41,859	42,538	43,209	43,873	44,547	45,220	45,900	46,568
	Total	188,583	192,308	196,261	200,390	204,298	208,102	212,038	215,959	219,790
Net Base Resource Capacity	Canada	24,869	25,343	26,509	26,403	26,403	26,403	26,403	26,403	26,403
	Northwest	43,331	43,329	43,336	43,343	43,343	43,368	43,393	43,418	43,418
	Basin	12,410	12,515	12,561	12,622	12,622	12,622	12,622	12,622	12,622
	Rockies	17,093	17,866	18,380	18,425	19,154	19,154	19,154	19,151	19,151
	Desert SW	40,511	40,957	41,441	41,703	41,703	41,703	41,703	41,703	41,703
	No. CA	31,153	31,196	31,197	31,197	31,197	31,197	31,197	31,197	31,196
	So. CA/MX	31,610	31,737	31,863	31,865	31,865	31,865	31,865	31,865	31,865
	Total	200,978	202,943	205,289	205,559	206,288	206,313	206,338	206,360	206,359
Other Outages and Line Losses	Canada	-1,876	-1,888	-1,894	-1,897	-1,897	-1,896	-1,897	-1,897	-1,896
	Northwest	-718	-713	-684	-686	-676	-672	-739	-724	-697
	Basin	-201	-205	-205	-208	-204	-199	-189	-184	-189
	Rockies	-71	-64	-68	-69	-72	-71	-65	-58	-58
	Desert SW	-189	-182	-156	-149	-153	-149	-149	-149	-149
	No. CA	-204	-209	-210	-210	-210	-206	-205	-204	-203
	So. CA/MX	-611	-610	-599	-587	-579	-578	-575	-573	-572
	Total	-3,869	-3,871	-3,816	-3,807	-3,790	-3,772	-3,818	-3,788	-3,764
SAM Net Imports (+) (negative if exporting)	Canada	-1,145	-1,021	-1,544	-1,305	-1,184	-1,141	-1,038	-947	-816
	Northwest	-7,102	-7,293	-6,652	-6,967	-7,133	-7,184	-7,287	-7,378	-7,509
	Basin	1,973	2,203	2,466	2,517	2,517	2,462	2,437	2,437	2,437
	Rockies	-1,619	-2,115	-2,239	-2,117	-2,179	-2,010	-1,984	-1,984	-1,984
	Desert SW	-2,994	-3,474	-4,257	-4,472	-4,319	-4,378	-4,329	-4,276	-4,223
	No. CA	684	1,107	1,583	2,045	2,361	2,413	2,466	2,518	2,569
	So. CA/MX	10,203	10,593	10,644	10,300	9,937	9,837	9,735	9,630	9,526
	Total	0	0	0	0	0	0	0	0	0
Available Resources including Transfers	Canada	21,848	22,434	23,070	23,201	23,322	23,365	23,468	23,559	23,691
	Northwest	35,511	35,322	36,000	35,689	35,534	35,512	35,367	35,316	35,212
	Basin	14,182	14,513	14,822	14,931	14,935	14,886	14,870	14,875	14,871
	Rockies	15,403	15,686	16,074	16,238	16,903	17,073	17,105	17,108	17,108
	Desert SW	37,329	37,302	37,028	37,083	37,232	37,176	37,226	37,279	37,332
	No. CA	31,633	32,094	32,570	33,032	33,349	33,405	33,459	33,512	33,562
	So. CA/MX	41,203	41,721	41,908	41,578	41,224	41,125	41,026	40,923	40,819
	Total	197,109	199,072	201,473	201,752	202,498	202,541	202,521	202,572	202,595
Power Supply Margin	Canada	1,348	1,460	1,499	1,082	618	214	-238	-641	-1,098
	Northwest	6,716	6,083	6,380	5,513	4,910	4,427	3,861	3,379	2,862
	Basin	0	0	0	-326	-652	-1,003	-1,338	-1,724	-1,960
	Rockies	0	0	0	-245	0	-216	-586	-1,043	-1,462
	Desert SW	463	-640	-2,037	-3,031	-3,885	-5,030	-6,088	-7,067	-8,107
	No. CA	0	0	0	0	-141	-531	-934	-1,314	-1,682
	So. CA/MX	0	-138	-630	-1,632	-2,650	-3,422	-4,194	-4,977	-5,749
	Total	8,526	6,765	5,212	1,362	-1,800	-5,561	-9,518	-13,387	-17,195

Table 22 - Sub-region Summary - Case #4

Parameter	Sub-region	2009	2010	2011	2012	2013	2014	2015	2016	2017
Firm Demand	Canada	22,336	22,903	23,532	24,104	24,710	25,173	25,682	26,193	26,796
	Northwest	30,116	30,452	30,846	31,242	31,614	31,977	32,362	32,724	33,159
	Basin	10,336	10,579	10,695	11,024	11,223	11,455	11,657	11,898	12,051
	Rockies	11,626	11,813	12,058	12,364	12,635	12,929	13,223	13,526	13,867
	Desert SW	20,036	20,575	21,127	21,709	22,223	22,801	23,389	23,938	24,525
	No. CA	19,286	19,575	19,882	20,177	20,470	20,758	21,032	21,287	21,552
	So. CA/MX	25,939	26,341	26,758	27,171	27,581	27,993	28,408	28,826	29,228
	Total	139,675	142,238	144,898	147,791	150,456	153,086	155,753	158,392	161,178
Non-Firm Demand	Canada	0	0	0	0	0	0	0	0	0
	Northwest	0	0	0	0	0	0	0	0	0
	Basin	213	213	213	213	213	213	213	213	213
	Rockies	206	241	263	267	272	273	275	276	277
	Desert SW	647	641	658	645	653	658	677	680	684
	No. CA	985	1,000	1,014	1,028	1,042	1,056	1,070	1,083	1,097
	So. CA/MX	1,153	1,170	1,188	1,206	1,223	1,239	1,256	1,273	1,289
	Total	3,204	3,265	3,336	3,359	3,403	3,439	3,491	3,525	3,560
Building Block Reserve Requirement	Canada	2,957	3,032	3,116	3,191	3,272	3,333	3,400	3,468	3,548
	Northwest	4,767	4,821	4,883	4,946	5,005	5,062	5,123	5,180	5,249
	Basin	1,208	1,237	1,251	1,289	1,312	1,339	1,363	1,391	1,409
	Rockies	1,554	1,579	1,611	1,652	1,688	1,728	1,767	1,808	1,853
	Desert SW	2,559	2,627	2,698	2,772	2,838	2,912	2,987	3,057	3,132
	No. CA	2,135	2,167	2,200	2,233	2,266	2,297	2,328	2,356	2,385
	So. CA/MX	3,073	3,119	3,168	3,216	3,263	3,311	3,359	3,407	3,454
	Total	18,253	18,582	18,927	19,299	19,643	19,982	20,327	20,667	21,030
Load Requirement	Canada	25,293	25,935	26,648	27,295	27,982	28,506	29,082	29,661	30,344
	Northwest	34,883	35,273	35,729	36,188	36,619	37,039	37,485	37,904	38,408
	Basin	11,757	12,029	12,159	12,526	12,748	13,007	13,233	13,502	13,673
	Rockies	13,386	13,633	13,932	14,283	14,595	14,930	15,265	15,610	15,997
	Desert SW	23,242	23,843	24,483	25,126	25,714	26,371	27,053	27,675	28,341
	No. CA	22,406	22,742	23,096	23,438	23,778	24,111	24,430	24,726	25,034
	So. CA/MX	30,165	30,630	31,114	31,593	32,067	32,543	33,023	33,506	33,971
	Total	161,132	164,085	167,161	170,449	173,502	176,507	179,571	182,584	185,768
Net Base Resource Capacity	Canada	24,281	24,740	25,519	25,519	25,519	25,519	25,519	25,519	25,519
	Northwest	41,940	41,945	41,953	41,960	41,985	42,010	42,035	42,034	42,034
	Basin	12,267	12,352	12,431	12,476	12,476	12,476	12,476	12,476	12,476
	Rockies	17,395	18,266	18,686	18,730	19,456	19,456	19,456	19,456	19,456
	Desert SW	41,926	41,972	42,456	42,438	42,438	42,438	42,438	42,438	42,438
	No. CA	31,040	31,088	31,088	31,088	31,088	31,088	31,088	31,088	31,088
	So. CA/MX	31,401	31,532	31,655	31,656	31,656	31,656	31,656	31,656	31,656
	Total	200,249	201,895	203,787	203,867	204,618	204,643	204,668	204,667	204,667
Other Outages and Line Losses	Canada	-608	-595	-590	-594	-599	-600	-604	-606	-610
	Northwest	-235	-161	-165	-60	-47	-21	-124	-118	-119
	Basin	-124	-142	-146	-157	-163	-170	-175	-178	-179
	Rockies	-119	-120	-127	-135	-137	-136	-131	-126	-124
	Desert SW	-742	-742	-849	-548	-669	-1,156	-635	-1,207	-1,114
	No. CA	-924	-879	-878	-878	-880	-877	-876	-877	-876
	So. CA/MX	-1,607	-1,698	-1,838	-1,848	-1,852	-1,856	-1,853	-1,861	-1,860
	Total	-4,358	-4,337	-4,593	-4,222	-4,346	-4,816	-4,397	-4,971	-4,883
SAM Net Imports (+) (negative if exporting)	Canada	1,319	736	499	697	870	931	1,078	1,208	1,394
	Northwest	1,150	864	1,101	903	730	662	456	-69	-427
	Basin	-386	-181	-105	207	435	701	931	1,203	1,375
	Rockies	-2,731	-2,731	-2,731	-2,883	-3,090	-3,326	-3,070	-2,731	-2,731
	Desert SW	-2,595	-1,999	-1,786	-1,807	-1,996	-2,055	-2,457	-1,659	-1,110
	No. CA	68	-312	-1,225	-1,853	-2,164	-2,237	-1,952	-2,612	-2,351
	So. CA/MX	3,175	3,624	4,247	4,736	5,214	5,323	5,015	4,660	3,850
	Total	0	0	0	0	0	0	0	0	0
Available Resources including Transfers	Canada	24,992	24,881	25,428	25,622	25,791	25,851	25,993	26,121	26,303
	Northwest	42,855	42,648	42,889	42,803	42,668	42,651	42,367	41,847	41,488
	Basin	11,757	12,029	12,181	12,526	12,748	13,007	13,233	13,502	13,673
	Rockies	14,545	15,415	15,828	15,712	16,229	15,994	16,255	16,599	16,601
	Desert SW	38,589	39,230	39,821	40,082	39,774	39,227	39,345	39,572	40,214
	No. CA	30,184	29,896	28,985	28,356	28,044	27,973	28,260	27,599	27,861
	So. CA/MX	32,969	33,457	34,064	34,544	35,018	35,122	34,817	34,455	33,646
	Total	195,891	197,557	199,194	199,645	200,272	199,826	200,271	199,695	199,784
Power Supply Margin	Canada	-301	-1,054	-1,220	-1,673	-2,191	-2,655	-3,089	-3,540	-4,041
	Northwest	7,972	7,375	7,160	6,615	6,050	5,612	4,883	3,943	3,080
	Basin	0	0	22	0	0	0	0	0	0
	Rockies	1,159	1,782	1,895	1,428	1,634	1,064	990	990	604
	Desert SW	15,347	15,387	15,338	14,956	14,060	12,856	12,293	11,897	11,873
	No. CA	7,778	7,155	5,888	4,918	4,267	3,862	3,830	2,873	2,827
	So. CA/MX	2,804	2,827	2,950	2,951	2,951	2,579	1,794	949	-325
	Total	34,759	33,472	32,033	29,196	26,770	23,319	20,700	17,112	14,017

Table 23 - Sub-region Summary - Case #5

Parameter	Sub-region	2009	2010	2011	2012	2013	2014	2015	2016	2017
Firm Demand	Canada	18,418	18,844	19,380	19,872	20,398	20,800	21,298	21,742	22,271
	Northwest	25,201	25,584	25,914	26,383	26,775	27,178	27,547	27,924	28,285
	Basin	12,379	12,674	12,950	13,333	13,627	13,896	14,181	14,530	14,736
	Rockies	13,465	13,670	13,983	14,335	14,697	15,040	15,407	15,827	16,210
	Desert SW	32,001	32,899	33,870	34,802	35,675	36,627	37,583	38,486	39,442
	No. CA	26,106	26,486	26,879	27,260	27,639	28,009	28,387	28,745	29,092
	So. CA/MX	34,122	34,668	35,234	35,793	36,346	36,908	37,470	38,038	38,596
	Total	161,692	164,825	168,210	171,778	175,157	178,458	181,873	185,292	188,632
Non-Firm Demand	Canada	0	0	0	0	0	0	0	0	0
	Northwest	0	6	10	30	30	30	30	30	30
	Basin	297	297	297	302	302	302	302	302	302
	Rockies	354	408	446	462	477	480	472	462	453
	Desert SW	619	677	700	693	707	718	743	752	762
	No. CA	1,484	1,507	1,529	1,551	1,571	1,590	1,611	1,630	1,648
	So. CA/MX	1,523	1,546	1,569	1,592	1,615	1,637	1,659	1,681	1,703
	Total	4,277	4,441	4,551	4,630	4,702	4,757	4,817	4,857	4,898
Demand Escalation (or assumed reserve margin)	Canada	2,763	2,827	2,907	2,981	3,060	3,120	3,195	3,261	3,341
	Northwest	3,780	3,838	3,887	3,957	4,016	4,077	4,132	4,189	4,243
	Basin	1,857	1,901	1,943	2,000	2,044	2,084	2,127	2,180	2,210
	Rockies	2,020	2,051	2,097	2,150	2,205	2,256	2,311	2,374	2,432
	Desert SW	4,800	4,935	5,081	5,220	5,351	5,494	5,637	5,773	5,916
	No. CA	4,139	4,199	4,261	4,322	4,382	4,440	4,500	4,556	4,611
	So. CA/MX	5,347	5,432	5,520	5,608	5,694	5,782	5,869	5,958	6,045
	Total	24,705	25,182	25,696	26,238	26,751	27,253	27,771	28,290	28,797
Load Requirement	Canada	21,181	21,671	22,287	22,853	23,458	23,920	24,493	25,003	25,612
	Northwest	28,981	29,428	29,811	30,370	30,821	31,285	31,709	32,143	32,558
	Basin	14,533	14,872	15,190	15,635	15,973	16,282	16,610	17,012	17,248
	Rockies	15,839	16,129	16,526	16,947	17,379	17,776	18,190	18,663	19,095
	Desert SW	37,420	38,511	39,651	40,715	41,733	42,839	43,963	45,011	46,120
	No. CA	31,729	32,192	32,669	33,133	33,592	34,039	34,498	34,931	35,351
	So. CA/MX	40,992	41,646	42,323	42,993	43,655	44,327	44,998	45,677	46,344
	Total	190,674	194,448	198,457	202,646	206,610	210,468	214,461	218,439	222,327
Net Base Resource Capacity	Canada	24,870	25,142	25,373	25,267	25,267	25,267	25,267	25,267	25,267
	Northwest	43,221	43,219	43,227	43,233	43,233	43,258	43,283	43,308	43,308
	Basin	12,393	12,404	12,404	12,404	12,404	12,404	12,404	12,404	12,404
	Rockies	17,060	17,810	17,810	17,810	17,810	17,810	17,810	17,810	17,810
	Desert SW	40,479	40,879	41,363	41,363	41,363	41,363	41,363	41,363	41,363
	No. CA	31,030	31,074	31,075	31,075	31,075	31,075	31,075	31,075	31,074
	So. CA/MX	31,610	31,737	31,863	31,865	31,865	31,865	31,865	31,865	31,865
	Total	200,663	202,265	203,115	203,017	203,017	203,042	203,067	203,092	203,091
Other Outages and Line Losses	Canada	-1,887	-1,897	-1,897	-1,897	-1,897	-1,897	-1,897	-1,897	-1,897
	Northwest	-706	-695	-654	-656	-647	-645	-713	-701	-677
	Basin	-206	-202	-197	-193	-186	-185	-178	-178	-183
	Rockies	-59	-56	-50	-50	-47	-47	-45	-43	-43
	Desert SW	-192	-166	-153	-149	-149	-149	-149	-149	-149
	No. CA	-205	-204	-205	-209	-208	-207	-204	-200	-201
	So. CA/MX	-607	-604	-591	-582	-577	-575	-574	-572	-569
	Total	-3,861	-3,824	-3,747	-3,736	-3,711	-3,705	-3,759	-3,739	-3,719
SAM Net Imports (+) (negative if exporting)	Canada	-455	-202	-72	0	0	0	0	0	0
	Northwest	-7,870	-8,123	-8,253	-8,325	-8,325	-8,325	-8,325	-8,325	-8,325
	Basin	2,346	2,537	2,537	2,462	2,437	2,437	2,443	2,534	2,537
	Rockies	-1,801	-2,024	-2,024	-2,024	-2,024	-2,024	-2,024	-2,024	-2,024
	Desert SW	-3,112	-3,899	-4,294	-4,412	-4,365	-4,316	-4,266	-4,213	-4,159
	No. CA	903	1,323	1,799	2,267	2,491	2,544	2,590	2,551	2,601
	So. CA/MX	9,988	10,389	10,307	10,032	9,786	9,685	9,581	9,476	9,370
	Total	0	0	0	0	0	0	0	0	0
Available Resources	Canada	22,529	23,043	23,404	23,370	23,370	23,370	23,370	23,370	23,370
	Northwest	34,644	34,401	34,320	34,252	34,261	34,288	34,245	34,282	34,306
	Basin	14,533	14,739	14,744	14,674	14,655	14,656	14,670	14,761	14,758
	Rockies	15,200	15,730	15,736	15,736	15,739	15,738	15,741	15,743	15,743
	Desert SW	37,176	36,814	36,917	36,803	36,850	36,898	36,949	37,002	37,056
	No. CA	31,729	32,192	32,669	33,133	33,358	33,412	33,461	33,426	33,473
	So. CA/MX	40,992	41,522	41,579	41,315	41,074	40,975	40,872	40,770	40,667
	Total	196,802	198,442	199,368	199,281	199,307	199,337	199,308	199,353	199,372
Power Supply Margin	Canada	1,348	1,372	1,117	517	-88	-550	-1,123	-1,633	-2,242
	Northwest	5,663	4,974	4,509	3,881	3,440	3,003	2,536	2,140	1,749
	Basin	0	-133	-446	-961	-1,318	-1,627	-1,940	-2,251	-2,491
	Rockies	-639	-399	-790	-1,211	-1,640	-2,038	-2,449	-2,920	-3,351
	Desert SW	-244	-1,697	-2,734	-3,913	-4,884	-5,941	-7,015	-8,009	-9,065
	No. CA	0	0	0	0	-234	-627	-1,037	-1,505	-1,878
	So. CA/MX	0	-124	-745	-1,678	-2,581	-3,352	-4,126	-4,907	-5,677
	Total	6,128	3,994	911	-3,365	-7,304	-11,131	-15,153	-19,087	-22,955

Attachment 4: WECC Power Supply Assessment Policy

WESTERN ELECTRICITY COORDINATING COUNCIL POWER SUPPLY ASSESSMENT POLICY

INTRODUCTION

The Western Electricity Coordinating Council was established to promote the reliable operation of the interconnected bulk power system by the coordination of planning and operation of generating and interconnected transmission facilities.

The Planning Coordination Committee (PCC) assigned the Load and Resource Subcommittee (LRS) the task of developing an Adequacy of Supply Assessment Methodology. This document establishes the policy for conducting power supply assessments using the methodology developed by the LRS. This policy shall be periodically reviewed and revised as experience indicates.

PURPOSE OF POWER SUPPLY ASSESSMENT

To ensure the reliability of the interconnected bulk electric system, it is necessary to assess both the security and the adequacy of the overall Western Interconnection. This document is focused on the portion of the assessment dealing with the adequacy of power supply. As electric industry restructuring has altered the traditional model of the vertically integrated utility, the responsibility for maintaining the adequacy of the power supply is distributed among multiple private and public entities, in part relying on market mechanisms. Though there may not be specific entities entrusted to plan for adequate resources, there exists a need to assess whether projected resources will be sufficient to reliably meet demand. Such information will allow regulators and policy makers to anticipate potential shortfalls. Determinations can be made as to whether impediments or insufficient incentives exist in the market and whether utility integrated resource planning is bringing resources on line in a timely manner. Additionally, a high quality assessment can support efficient sharing of resources among sub-regions where feasible, and can inform transmission expansion planning efforts of the WECC Transmission Expansion Planning Policy Committee.

It is not the intent of an adequacy assessment to replace the market, create sanctionable criteria or anticipate future energy prices. Its purpose is to project whether enough physical resources exist, at any price, to meet load and possible reserves while considering the transmission transfer capabilities of major paths. Such an assessment will be consistent with the NERC Standards.

It is recognized that it is impossible to provide 100% adequacy of power supply over all future circumstances. It is the purpose of this document to establish a uniform policy for assessing the adequacy of installed and identified future resources within the WECC region for the purposes of reporting within the Council, and to outside agencies. The assessments shall cover a period encompassing at least the next 5 years.

The Power Supply Assessment Methodology shall be developed and maintained by LRS. Adequacy of supply may be defined and measured in terms of generating reserve margins and

transmission limitations between load and resource areas and/or based on probabilistic methods. Assessments shall consider both capacity and energy adequacy. Appropriate technical tools shall be developed and utilized in conducting the assessments. The assessments shall account for diversity of load and generation, and account for transmission constraints between load and resource areas. To the extent that fuel supply interruptions are judged to be a valid and significant source of uncertainty this vulnerability should also be assessed.

CAPACITY ASSESSMENT METHODOLOGY AND RESOURCE ASSESSMENT GUIDELINES

As approved by the Board of Directors in July 2007, development of resource adequacy numerical guidelines for use in capacity (MW) assessments will use the Building Block approach. Components of the Building Block approach approved by the board include the following: provisions for contingency reserves, regulating reserves (both of which are required operating reserve components), additional forced outages to cover additional contingencies and temperature-induced load variations beyond expected peak loads. The method for determining a numerical value for sub-regions of WECC using these building blocks, and other influences on reliability, shall be determined by LRS with the concurrence of PCC.

DATA REQUIREMENTS:

To aid WECC in assessing resource adequacy, the following general kinds of information shall be provided by WECC members:

Load Forecasts

- Electricity demand and energy forecasts, including uncertainties
  - Variations due to weather
  - Variations due to other factors affecting forecasts

Demand Side Management (DSM) Programs

- Existing and planned demand-side management programs
  - Direct controlled interruptible loads
  - Aggregate effects of multiple DSM programs

Resource Information

- Supply-side resource characteristics, including uncertainties
  - Consistent generator unit ratings, including seasonal variations and environmental considerations affecting hydro and thermal units
  - Availability of generating units
  - Fuel type
  - Fuel Supply risks

Transmission Information

- Capabilities, availability of transmission capacity, and other uncertainties

REPORTING OF POWER SUPPLY ADEQUACY

The assessment of generating reserve margins and transmission limitations between load and resource areas, accounting for uncertainties, shall be developed and the results reported on a seasonal basis. The assessment shall be consistent with the requirement for maintaining operating reserves as defined in the *WECC Minimum Operating Reliability Criteria* and NERC Operating Policies.

The results of this assessment should be packaged in a way to be useful to the WECC Board of Directors, regulatory and policy agencies of the states/provinces, and sub-regions that are interested in electricity reliability and adequacy throughout the footprint of the Western Interconnection. WECC should directly communicate the results to this community. In addition, WECC staff and LRS members should present the results to this community at meetings and other appropriate forums.

Prepared by Load and Resources Subcommittee	September, 2007
Approved by Planning Coordination Committee	October 26, 2007
Approved by Board of Directors	December 6, 2007

Attachment 5: 1-in-2 to 1-in-10 Calculation

EXAMPLE

	Summer Temp
1990	91.0
1991	94.0
1992	97.0
1993	89.3
1994	95.5
1995	92.7
1996	92.0
1997	88.2
1998	93.0
1999	99.2
2000	91.5
2001	98.3
2002	102.8
2003	102.0
2004	95.2
2005	95.8
2006	95.2

AVG	94.9
STD	4.1

z = (x - xbar)/s
x = xbar + z*s

z =	1.28
Temp =	100.121
Pr() =	0.900

Temp Increase	5.3
MW/Degree	7.030
MW Increase	37.0
MW Load	1,500
% Increase	2.5%

Attachment 6: Relationship of the Power Supply Assessment to Individual Load Serving Entities' Resource Adequacy Standards and Analyses

The values for reserve margins used in the PSA are not directly comparable to any values that might be used by individual LSEs or their regulators or local governing boards to evaluate their individual resource adequacy. Moreover, they are not intended to supplant any of those values. They are provided for the use of the WECC board and other users of the report to assess the overall state of the adequacy of the Western Interconnection.

A number of things make the reserve margins in the PSA not comparable to the values chosen by or applicable to an individual LSE.

First, any given LSE may use different building blocks or different values for the building blocks, or even an entirely different method to set its target reserve margin, than what is used in the PSA. For instance an LSE may include the effect of 1–in–20 weather in its margin, rather than the 1–in–10 weather used in the PSA. It may include a factor to account for delays in expected future plant construction, a concern that is addressed in a different way in the PSA.

Second, the data are collected and analyzed by Balancing Authority. There are 35 Balancing Authority areas in WECC. In many cases the Balancing Authority boundary is the same as that of an LSE, but in several significant instances, they are not. For instance, the CAISO Balancing Authority area contains three very large LSEs, PG&E, SCE and SDG&E, each of which may want to set their own reserve margins, subject to the regulation of the CPUC.

Further, there are 13 Electricity Service Providers (ESP) in California with no fixed customer service requirements and no obligation to plan loads and resources beyond those established by CPUC and CAISO year-ahead resource adequacy requirements. Finally, there are about 25 additional publicly-owned utilities, which encompass traditional utilities and joint power authorities operating much like an ESP. This amalgam of LSEs exists in conjunction with a generating industry that is partially merchant-owned and partially LSE-owned. Under these circumstances the CAISO has a more difficult job to project aggregate loads and to describe resource additions accurately than does an integrated utility also operating as a Balancing Authority.

As an example of this effect, this Balancing Authority exhibits substantial load diversity, which is moderated when looking at the Balancing Authority's loads as a whole. This affects the building block component for 1–in–10 weather stresses. For instance, the California Bay area by itself would exhibit about a 7% weather adder for such a weather stress, but in the context of larger areas we see smaller adders, up to the overall CAISO Balancing Authority area where we see an adder for the overall load that is lower than this. The PSA has included separate weather analyses of the three LSEs in the CAISO footprint.

Third, the "bubbles" that are the basic units for the analysis of the PSA, which employs a model called SAM, are in a number of cases made up of several Balancing Authorities, as well as some being identical to an individual Balancing Authority, some being generator-only entities, and in one case, containing only a part of a Balancing Authority. For instance, the IID bubble is only the Imperial Irrigation District area, the Four Corners bubble is generation only, the Arizona bubble is four Balancing Authorities (APS, SRP, TEP and WALC), and the Northern California bubble consists of only a piece of the CAISO but more than one LSE. There are 26 bubbles in SAM.

Fourth, the margins developed at the Balancing Authority level are averaged across seven sub-regions that are larger (and in some cases, substantially larger) than individual Balancing Authority areas and then the sub-region averages are used for each of the bubbles in the sub-regions. The sub-regions used in the PSA are shown in Table 24 below, as well as the SAM bubbles that make up each sub-region and the resulting values for winter and summer.

Table 24

Sub-Region	SAM Zones Included in Sub-Region	Summer Margin	Winter Margin
Canada	British Columbia, Alberta	11.3%	13.2%
Northwest	Pacific Northwest, COB, Montana	14.3%	15.8%
Basin	Idaho, Northern Nevada, Utah, Intermountain Power Project	12.2%	11.7%
Rockies	Colorado East, Colorado West, Wyoming	11.8%	13.4%
Desert Southwest	Arizona, New Mexico, Southern Nevada, Imperial Irrigation District, Four Corners, Palo Verde	13.3%	12.8%
Northern California	Northern California, Central California, San Francisco, SMUD	14.7%	10.5%
Southern California/Mexico	Southern California Edison, San Diego Gas & Electric, LADWP, Comision Federal de Electricidad (CFE)	15.7%	11.4%
WECC Total		13.7%	12.9%

The sequence described above is done for several reasons, having to do primarily with constraints on the data and on the analytic method itself.

The primary data constraint is that we do not ask for, and cannot take account of, any contractual obligations between LSEs that might shift resources from one LSE or bubble to another. The PSA only accounts for the ownership splits for some jointly owned plants, those whose output is divided among LSEs that are incorporated into different bubbles. The PSA is a physical load and resource analysis and is not designed to evaluate the ability of any individual LSE to meet its load in the future.

The analytical limitation has to do with how SAM simulates economy transactions among bubbles, after individual bubble loads are met by resources in the bubble, subject to transmission limitations among the bubbles. The process for meeting deficit-bubble needs by surplus-bubble resources is governed by the internal algorithm of SAM, which essentially meets the needs of the closest bubble first. There are not economic or contractual drivers to this process.

Both of these considerations, as well as the aggregation of LSEs into bubbles, substantially limit the applicability of the analysis to individual LSEs, so as to make any attempt to derive individual LSE information from the analysis of very limited value. The level at which the analysis is meaningful and informative is the sub-region level for which the results are reported.

Attachment 7: Energy Assessment – Pacific Northwest

In an ongoing effort to improve WECC's Power Supply Assessment, the Bonneville Power Administration (BPA) and the Northwest Power and Conservation Council (NWPCC) have again prepared an energy assessment for the Pacific Northwest (PNW), which has been vetted with representatives of public and investor-owned utilities, state regulatory and energy offices and other northwest energy stakeholders through PNW Resource Adequacy Forum and NWPCC meetings.

Since the PNW (defined in the 1980 Power Act as the U.S. Columbia River drainage including Washington, Oregon, Idaho, part of Montana and small parts of several other states) is energy- rather than capacity-constrained, BPA and the NWPCC undertook the task to develop an energy assessment described in this Attachment.

The tables at the end of this attachment show monthly load/resource balances for the water years 2011 (Sep 2010 - Aug 2011) and 2013 (Sep 2012 - Aug 2013).

The load/resource balance includes projected loads, existing generation and demand-side management resources, and future committed resources for the Pacific Northwest as well as firm imports and exports. It also includes PNW regional market resources, that is, independent power producer (IPP) generators not under contract to load-serving entities. Critical hydro generation is based on historical stream flows from September of 1936 through August of 1937.

The load/resource balance calculated for the PNW adequacy standard includes contributions from "non-firm" resources. Non-firm resources include seasonal out-of-region market purchases, primarily from California[22], and additional hydro energy derived from the flexibility of the hydroelectric system. The value assigned to non-firm resources is characterized as a "planning adjustment," which is set via a loss-of-load-probability (LOLP) analysis, and is currently assessed at 1,300 average megawatts[23]. This value is the average annual usage of these two sources of non-firm energy as required to meet load in the hourly LOLP analysis with a 5% target, which equates PNW resource adequacy to avoidance of significant curtailments in 19 of 20 simulations.

CAVEAT: Note that there are a number of important differences between this analysis and that in the rest of the PSA: the definition of "committed" resources used in the PNW for this analysis is different, the load forecast is not the same as that used in the PSA and the analytical model is different from that used in the PSA. Moreover, the analysis for the PNW standard includes the ability to purchase from other sub-regions (primarily California) under different assumptions that used in the SAM analysis for the PSA.

[22] Maximum possible imports are set in the analysis to 3,000 MW in the months of October - May, and zero in the summer months June - September.

[23] An average megawatt is the unit of energy output over a year, equivalent to the energy produced by the continuous operation of one megawatt of capacity over that period of time (8,760 MWh).

2011 Energy Load/Resource Balance
(MWa)

Pacific Northwest Regional Resource Adequacy Assessment

Energy Load/Resource Balance Assessment **2011** **Bal =** **2584** **Threshold = 0**

NWPCC

May 28, 2008 **Last Update**

Summary	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Ann
Net Demand	21040	21096	22934	24769	25730	24734	23376	21858	21243	22170	22911	22793	**22882**
Net Resources	23599	24143	28231	28887	26262	25611	24504	22870	23440	26216	26412	25405	**25466**
L/R Balance	**2559**	**3047**	**5297**	**4118**	**532**	**877**	**1128**	**1012**	**2197**	**4046**	**3501**	**2612**	**2584**
W/O Plan Adjustment	1259	1747	3997	2818	-768	-423	-172	-288	897	2746	2201	1312	**1284**
W/O Uncontracted	259	747	652	-561	-4149	-3780	-3054	-2703	-1487	1746	1201	312	**-888**

Demand	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Ann
Non-DSI	19900	20300	22515	24475	25114	24074	22448	20793	20179	20965	21595	21317	**21966**
DSI	693	693	693	693	718	718	718	718	718	718	718	718	**710**
Coulee Pumping	137	65	2	2	2	2	28	158	238	255	274	238	**117**
Total	**20730**	**21058**	**23210**	**25171**	**25834**	**24795**	**23194**	**21670**	**21135**	**21938**	**22587**	**22273**	**22793**

Resources	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Ann
Critical Hydro	10579	11172	12724	13175	10482	10023	10740	10938	11487	15807	13300	12332	**11905**
Non-Hydro Firm	10720	10671	10862	11033	11099	10931	9582	8216	8270	8109	10812	10773	**10090**
PNW Uncontracted	1000	1000	3345	3379	3381	3357	2882	2415	2384	1000	1000	1000	**2171**
Planning Adjustment	1300	1300	1300	1300	1300	1300	1300	1300	1300	1300	1300	1300	**1300**

Firm Contracts	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Ann
Exports	1169	948	909	957	950	945	972	915	786	1022	1177	1216	**997**
Imports	859	910	1185	1359	1054	1006	790	727	678	790	853	696	**908**

PNW uncontracted resources are reduced during the peak SW load months June-October.

LEGEND:

NET DEMAND: Average annual firm load based on average temperature conditions and adjusted for firm out-of-region energy sales and purchases.
CRITICAL HYDRO: Hydro generation under current constraints for hydrologic conditions from August 1936 through July 1937.
NON-HYDRO FIRM: Annual energy capability from all non-hydro resources committed to serve PNW load accounting for maintenance and forced-outage rates & limited by fuel-supply constraints/environmental constraints (wind assumed at 30% plant factor unless better information available)
PNW UNCONTRACTED: Merchant generation located in the PNW, but not committed to load through long-term contracts.
PLANNING ADJUSTMENT: Additional energy available to PNW from out-of-region spot market and hydro flexibility derived from 5% LOLP study.

2013 Energy Load/Resource Balance (MWa)

Pacific Northwest Regional Resource Adequacy Assessment

Energy Load/Resource Balance Assessment **2013** **Bal =** **1879** **Threshold = 0**

NWPCC

May 28, 2008 **Last Update**

Summary	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Ann
Net Demand	21851	22151	23916	25751	26468	25408	23906	22537	21909	22658	23652	23354	**23625**
Net Resources	23623	24171	28265	28921	26290	25639	24533	22902	23481	26283	26469	25455	**25504**
L/R Balance	**1772**	**2020**	**4349**	**3170**	**-178**	**231**	**627**	**366**	**1572**	**3625**	**2816**	**2101**	**1879**
W/O Plan Adjustment	472	720	3049	1870	-1478	-1069	-673	-934	272	2325	1516	801	**579**
W/O Uncontracted	-528	-280	-296	-1509	-4859	-4426	-3555	-3350	-2112	1325	516	-199	**-1592**

Demand	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Ann
Non-DSI	20484	21144	23281	25256	25858	24756	22989	21471	20844	21466	22352	21893	**22643**
DSI	818	818	818	818	818	818	818	818	818	818	818	818	**818**
Coulee Pumping	137	65	2	2	2	2	28	158	238	255	274	238	**117**
Total	**21439**	**22027**	**24101**	**26076**	**26678**	**25576**	**23835**	**22447**	**21900**	**22539**	**23444**	**22949**	**23578**

Resources	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Ann
Critical Hydro	10603	11200	12758	13209	10510	10051	10769	10971	11528	15874	13357	12382	**11943**
Non-Hydro Firm	10720	10671	10862	11033	11099	10931	9582	8216	8270	8109	10812	10773	**10090**
PNW Uncontracted	1000	1000	3345	3379	3381	3357	2882	2415	2384	1000	1000	1000	**2171**
Planning Adjustment	1300	1300	1300	1300	1300	1300	1300	1300	1300	1300	1300	1300	**1300**

Firm Contracts	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Ann
Exports	1095	860	813	851	847	842	876	830	703	927	1080	1116	**904**
Imports	683	736	998	1176	1057	1010	805	740	694	808	872	711	**857**

PNW uncontracted resources are reduced during the peak SW load months June-October.

LEGEND:

NET DEMAND: Average annual firm load based on average temperature conditions and adjusted for firm out-of-region energy sales and purchases.
CRITICAL HYDRO: Hydro generation under current constraints for hydrologic conditions from August 1936 through July 1937.
NON-HYDRO FIRM: Annual energy capability from all non-hydro resources committed to serve PNW load accounting for maintenance and forced-outage rates & limited by fuel-supply constraints/environmental constraints (wind assumed at 30% plant factor unless better information available)
PNW UNCONTRACTED: Merchant generation located in the PNW, but not committed to load through long-term contracts.
PLANNING ADJUSTMENT: Additional energy available to PNW from out-of-region spot market and hydro flexibility derived from 5% LOLP study.

Attachment 8: Generation Additions/Retirements

Class 1 Additions

Area	Balancing Authority	Name	Unit Type	Capacity MW Summer	Capacity MW Winter	Fuel Type	Commercial Operation Dates Original Year	Commercial Operation Dates Revised Year	Commercial Operation Dates Revised Month	Status
NWCA	AESO	Confidential Project	GT	47	47	NG	2008	2008	6	U
NWCA	AESO	Christina Lake	GT	85	85	NG	2008	2008	7	V
NWCA	AESO	Horizon Phase I	GT	101	101	NG	2007	2008	12	V
PV	APS	Palo Verde	NP	71	71	NUC	2005	2008	1	A
AZ	APS	White Mountain	BM	24	24	WDS	2008	2008	6	V
IID	APS	Yucca	GT	48	48	NG	2008	2008	8	U
IID	APS	Yucca	GT	48	48	NG	2008	2008	8	U
NWCB	BC Hydro	S Slocan	HY	2	2	WAT	2006	2008	5	A
NWCB	BC Hydro	Aberfeldie 2	HY	7	0	WAT	2008	2008	8	U
NWCB	BC Hydro	Aberfeldie 2	HY	7	0	WAT	2008	2008	8	U
NWCB	BC Hydro	Aberfeldie 2	HY	8	0	WAT	2008	2008	8	U
NWCB	BC Hydro	Corra Linn	HY	2	2	WAT	2005	2008	12	A
NWCB	BC Hydro	Savona ERG	OT	5	1	OTH	2008	2008	4	U
NWCB	BC Hydro	Zeballos Lake	HY	4	11	WAT	2008	2008	4	U
NWCB	BC Hydro	150 Mile House ERG	OT	3	1	OTH	2008	2008	6	U
NWCB	BC Hydro	Mount Hays Wind	WT	25	25	WND	2008	2008	10	U
NWCB	BC Hydro	Eldorado Reservoir	HY	<1	<1	WAT	2008	2008	12	V
NWUW	BPA	Grays Harbor	CT	170	170	NG	2003	2008	6	V
NWUW	BPA	Grays Harbor	CT	170	170	NG	2003	2008	6	V
NWUW	BPA	Grays Harbor	CA	260	260	NG	2003	2008	6	V
SCE	CISO	Dillon Wind	WT	101	101	WND	2008	2008	1	U
PGEN	CISO	Chowchilla Biomass	BM	13	13	WDS	2007	2008	1	V
SCE	CISO	Inland Empire	CC	405	405	NG	2008	2008	1	V
SCE	CISO	Inland Empire	CC	405	405	NG	2008	2008	2	V
SCE	CISO	Wintec III	WT	12	12	WND	2007	2008	2	U
PGEN	CISO	El Nido	BM	13	13	WDS	2007	2008	2	U
SDGE	CISO	Wellhead Margarita	GT	50	50	NG	2008	2008	5	U
PGES	CISO	Ox Mountain LF	BM	11	11	LFG	2007	2008	9	U
SDGE	CISO	Olivenhain-Hodges	PS	20	20	WAT	2008	2008	9	U
SDGE	CISO	Olivenhain-Hodges	PS	20	20	WAT	2008	2008	9	U
PGEN	CISO	Gateway	CC	530	530	NG	2009	2008	9	V
PGES	CISO	Pacific Renewable	WT	120	120	WND	2008	2008	10	U
SCE	CISO	Chiquita Canyon LF	BM	9	9	LFG	2007	2008	11	V
PGEN	CISO	Shiloh II	WT	150	150	WND	2008	2008	11	U
SDGE	CISO	Otay Mesa	CC	550	550	NG	2002	2008	11	U
PGEN	CISO	Eastshore	IC	118	118	NG	2009	2008	11	U
IID	IID	Niland	GT	45	45	NG	2007	2008	6	V
IID	IID	Niland	GT	45	45	NG	2009	2008	6	V
ID	IPC	Treasure Valley	BM	3	3	OBG	2008	2008	1	TS
ID	IPC	Bennett Creek	WT	20	20	WND	2008	2008	6	U
ID	IPC	Danskin	GT	165	178	NG	2008	2008	6	U
ID	IPC	Hot Springs	WT	20	20	WND	2008	2008	12	U
ID	IPC	Cassia Gulch	WT	19	19	WND	2007	2008	12	U
LDWP	LDWP	Haynes	ST	-41	-41	NG	2008	2008	1	D
LDWP	LDWP	Haynes	ST	-41	-41	NG	2008	2008	1	D
SMUD	MID	Hershey Cogen	GT	-5	-5	NG	1994	2008	1	RT
NVS	NPC	Clark	GT	52	52	NG	2008	2008	6	U
NVS	NPC	Clark	GT	52	52	NG	2008	2008	6	U
NVS	NPC	Clark	GT	52	52	NG	2008	2008	6	U
NVS	NPC	Clark	GT	52	52	NG	2008	2008	6	U
NVS	NPC	Clark	GT	52	52	NG	2008	2008	6	U
NVS	NPC	Clark	GT	52	52	NG	2008	2008	6	U
NVS	NPC	Clark	GT	52	52	NG	2008	2008	6	U
NVS	NPC	Clark	GT	52	52	NG	2008	2008	6	U
WY	PAC East	Mountain Wind I	WT	60	60	WND	2007	2008	3	V
WY	PAC East	Mountain Wind II	WT	80	80	WND	2007	2008	9	U
UT	PAC East	Spanish Fork	WT	19	19	WND	2008	2008	6	V
WY	PAC East	Glenrock	WT	99	99	WND	2008	2008	12	U
NWUW	PAC West	Condit	HY	-7	-7	WAT	2006	2008	10	RT
NWUW	PAC West	Condit	HY	-7	-7	WAT	2006	2008	10	RT
NWUW	PAC West	Marengo	WT	70	70	WND	2008	2008	7	U
NWUW	PGE	Bull Run	HY	-6	-6	WAT	2008	2008	6	RT
NWUW	PGE	Bull Run	HY	-6	-6	WAT	2008	2008	6	RT
NWUW	PGE	Bull Run	HY	-6	-6	WAT	2008	2008	6	RT
NWUW	PGE	Bull Run	HY	-6	-6	WAT	2008	2008	6	RT
NM	PNM	Valencia GT	GT	140	140	NG	2008	2008	6	V
COE	PSCO	Logan County	WT	200	200	WND	2007	2008	1	V
COE	PSCO	Peetz Table	WT	200	200	WND	2007	2008	1	V

Class 1 Additions

Area	Balancing Authority	Name	Unit Type	Capacity MW Summer	Capacity MW Winter	Fuel Type	Commercial Operation Dates Original Year	Commercial Operation Dates Revised Year	Commercial Operation Dates Revised Month	Status
COE	PSCO	Cedar Creek	WT	20	20	WND	2007	2008	1	A
COE	PSCO	DADS	BM	1	1	LFG	2007	2008	5	U
COE	PSCO	DADS	BM	1	1	LFG	2007	2008	5	U
COE	PSCO	DADS	BM	1	1	LFG	2007	2008	5	U
COE	PSCO	DADS	BM	1	1	LFG	2007	2008	5	U
COE	PSCO	Lamar Plt	ST	25	25	BIT	2008	2008	5	V
COE	PSCO	Lamar Plt	ST	14	14	BIT	2008	2008	5	V
COE	PSCO	Plains End II	IC	8	8	NG	2008	2008	5	V
COE	PSCO	Plains End II	IC	8	8	NG	2008	2008	5	V
COE	PSCO	Plains End II	IC	8	8	NG	2008	2008	5	V
COE	PSCO	Plains End II	IC	8	8	NG	2008	2008	5	V
COE	PSCO	Plains End II	IC	8	8	NG	2008	2008	5	V
COE	PSCO	Plains End II	IC	8	8	NG	2008	2008	5	V
COE	PSCO	Plains End II	IC	8	8	NG	2008	2008	5	V
COE	PSCO	Plains End II	IC	8	8	NG	2008	2008	5	V
COE	PSCO	Plains End II	IC	8	8	NG	2008	2008	5	V
COE	PSCO	Plains End II	IC	8	8	NG	2008	2008	5	V
COE	PSCO	Plains End II	IC	8	8	NG	2008	2008	5	V
COE	PSCO	Plains End II	IC	8	8	NG	2008	2008	5	V
COE	PSCO	Plains End II	IC	8	8	NG	2008	2008	5	V
COE	PSCO	Rawhide	GT	138	138	NG	2008	2008	6	V
SMUD	SMUD	SCA	CT	8	9	NG	2008	2008	6	A
SMUD	SMUD	Solano Wind	WT	63	63	WND	2006	2008	12	U
NVN	SPP	Galena	GE	12	21	GEO	2008	2008	2	V
NVN	SPP	Naniwa Energy	GT	-51	-60	NG	2008	2008	3	RT
NVN	SPP	Naniwa Energy	GT	-51	-60	NG	2008	2008	3	RT
NVN	SPP	TS Power	ST	203	203	SUB	2007	2008	6	U
NVN	SPP	Tracy CC	CC	541	578	NG	2008	2008	6	U
NVN	SPP	Kings Beach	IC	-3	-3	DFO	2008	2008	10	RT
NVN	SPP	Kings Beach	IC	-3	-3	DFO	2008	2008	10	RT
NVN	SPP	Kings Beach	IC	-3	-3	DFO	2008	2008	10	RT
NVN	SPP	Kings Beach	IC	-3	-3	DFO	2008	2008	10	RT
NVN	SPP	Kings Beach	IC	-3	-3	DFO	2008	2008	10	RT
NVN	SPP	Kings Beach	IC	-3	-3	DFO	2008	2008	10	RT
NVN	SPP	Western 102	IC	-8	-8	NG	2008	2008	12	D
AZ	TEP	Black Mountain	GT	45	45	NG	2008	2008	6	V
AZ	TEP	Black Mountain	GT	45	45	NG	2008	2008	6	V
SMUD	WASN	Shasta	HY	17	17	WAT	2008	2008	9	A
		Wind Derates		-1,056	-1,118					
		Additions for 2008		5,154	5,113					
NWCA	AESO	Suncor Firebag	GT	170	170	NG	2006	2009	12	V
NWCA	AESO	Rossdale	ST	-69	-69	NG	2009	2009	12	RT
NWCA	AESO	Rossdale	ST	-69	-69	NG	2009	2009	12	RT
NWCA	AESO	Rossdale	ST	-73	-73	NG	2009	2009	12	RT
NWCB	BC Hydro	Ashlu Creek	HY	34	4	WAT	2009	2009	2	U
NWCB	BC Hydro	Lower Clowhom	HY	5	1	WAT	2009	2009	3	U
NWCB	BC Hydro	Cranberry Creek	HY	1	0	WAT	2009	2009	4	U
NWCB	BC Hydro	Bear Mountain	WT	120	120	WND	2009	2009	9	U
NWCB	BC Hydro	Forrest Kerr	HY	96	14	WAT	2009	2009	9	U
NWCB	BC Hydro	Bone Creek Hydro	HY	15	2	WAT	2009	2009	10	U
NWCB	BC Hydro	Clemina Creek	HY	5	1	WAT	2009	2009	10	U
NWCB	BC Hydro	Maroon Creek	HY	1	1	WAT	2009	2009	10	U
NWCB	BC Hydro	Serpentine Ck	HY	4	0	WAT	2009	2009	10	U
NWCB	BC Hydro	Upper Clowhom	HY	4	1	WAT	2009	2009	10	U
NWCB	BC Hydro	Kwalsa Energy	HY	31	28	WAT	2009	2009	11	U
NWCB	BC Hydro	Raging River	HY	<1	<1	WAT	2009	2009	11	U
MXW	CFE	Pdte.Juárez	CC	259	259	NG	2009	2009	3	U
PGEs	CISO	Panoche EC	GT	401	401	NG	2009	2009	4	V
LDWP	LDWP	Castaic	PS	20	20	WAT	2009	2009	1	A
LDWP	LDWP	Pine Tree	WT	120	120	WND	2004	2009	4	U
LDWP	LDWP	Renewable Project	FC	1	1	OBG	2009	2009	1	U
NVS	NPC	Clark	GT	52	52	NG	2009	2009	6	U
NVS	NPC	Clark	GT	52	52	NG	2009	2009	6	U
NVS	NPC	Clark	GT	52	52	NG	2009	2009	6	U
NVS	NPC	Clark	GT	52	52	NG	2009	2009	6	U
NVN	SPP	Saltwells	GE	3	10	GEO	2009	2009	9	U

Class 1 Additions

Area	Balancing Authority	Name	Unit Type	Capacity MW Summer	Capacity MW Winter	Fuel Type	Commercial Operation Dates Original Year	Commercial Operation Dates Revised Year	Commercial Operation Dates Revised Month	Status
NVN	SPP	Stillwater	GE	8	20	GEO	2009	2009	9	U
AZ	SRP	Springerville	ST	400	400	SUB	2010	2009	12	U
		Wind Derates		-201	-214					
		Additions for 2009		1,493	1,354					
NWCA	AESO	Wabamun	ST	-279	-279	SUB	2010	2010	12	RT
NWCB	BC Hydro	Brilliant Expansion	HY	19	68	WAT	2010	2010	2	U
NWCB	BC Hydro	E. Toba/Montrose	HY	110	39	WAT	2010	2010	7	U
NWCB	BC Hydro	Dokie Wind	WT	180	180	WND	2010	2010	11	U
NWCB	BC Hydro	Upper Stave Energy	HY	21	19	WAT	2010	2010	11	U
MXW	CFE	Cerro Prieto V	GE	107	107	GEO	2010	2010	4	U
LDWP	LDWP	Castaic	PS	20	20	WAT	2006	2010	1	A
NWUW	PAC West	Powerdale	HY	-6	-6	WAT	1923	2010	4	RT
COE	PSCO	Comanche	ST	750	750	BIT	2009	2010	1	U
SMUD	WASN	Redding Power	CT	44	47	NG	2010	2010	7	U
		Wind Derates		-141	-129					
		Additions for 2010		825	817					
NWCA	AESO	Keephills	ST	450	450	SUB	2011	2011	4	V
NWCA	AESO	Rainbow	GT	-30	-30	NG	2011	2011	12	RT
NWCA	AESO	Rainbow	GT	-40	-40	NG	2011	2011	12	RT
NWCA	AESO	Rainbow	GT	-20	-20	NG	2011	2011	12	RT
NWCA	AESO	Sturgeon	GT	-8	-8	NG	2011	2011	12	RT
NWCA	AESO	Sturgeon	GT	-8	-8	NG	2011	2011	12	RT
LDWP	LDWP	Castaic	PS	103	103	WAT	2011	2011	1	A
NVS	NPC	Allen	GT	484	484	NG	2011	2011	6	U
		Additions for 2011		931	931					

Class 2 Additions

Area	Balancing Authority	Name	Unit Type	Capacity MW Summer	Capacity MW Winter	Fuel Type	Commercial Operation Dates Original Year	Revised Year	Revised Month	Status
NWCB	BC Hydro	Bear Hydro	HY	2	2	WAT	2008	2008	12	T
NWCB	BC Hydro	Pierce Creek	HY	<1	<1	WAT	2008	2008	12	T
NWUW	BPA	Biglow Canyon	WT	126	126	WND	2006	2008	8	T
PGEN	CISO	Keller Canyon LF	BM	4	4	LFG	2008	2008	8	T
PGES	CISO	Starwood Power	GT	119	119	NG	2008	2008	12	T
UT	PAC East	Schwendiman	WT	20	20	WND	2008	2008	11	T
UT	PAC East	Seven Mile	WT	99	99	WND	2008	2008	12	T
		Wind Derates		-208	-208					
		Additions for 2008		162	162					
NVN	SPP	Hot Sulphur Springs	GE	27	30	GEO	2009	2009	11	T
		Additions for 2009		27	30					
NVN	SPP	Carson Lake ORNI 16	GE	14	24	GEO	2010	2010	2	T
NVN	SPP	Faulkner	GE	19	25	GEO	2010	2010	2	T
NVN	SPP	Buffalo Valley	GE	14	24	GEO	2010	2010	5	T
		Additions for 2010		47	72					
NWCB	BC Hydro	Waneta Expansion	HY	435	435	WAT	2011	2011	1	T
NVN	SPP	Grass Valley	GE	14	24	GEO	2011	2011	2	T
NVN	SPP	Carson Lake Basin	GE	25	26	GEO	2011	2011	3	T
		Additions for 2011		473	485					
NM	PNM	Las Vegas GT	GT	-18	-18	DFO	2007	2012	1	RT
NVN	SPP	Carson Lake Basin	GE	25	26	GEO	2012	2012	3	T
		Additions for 2012		7	8					

Class 3 Additions

Area	Balancing Authority	Name	Unit Type	Capacity MW Summer	Capacity MW Winter	Fuel Type	Commercial Operation Dates Original Year	Commercial Operation Dates Revised Year	Commercial Operation Dates Revised Month	Status
NWCB	BC Hydro	Bear Hydro	HY	3	3	WAT	2008	2008	12	L
NWUW	BPA	Klondike Phase 3	WT	75	75	WND	2006	2008	4	T
NWUW	BPA	Leaning Juniper	WT	100	100	WND	2007	2008	8	T
NWUW	BPA	Arlington	WT	200	200	WND	2005	2008	9	T
NWUW	BPA	Miller Ranch	WT	100	100	WND	2008	2008	10	L
NWUW	BPA	Windy Point I	WT	80	80	WND	2008	2008	10	T
NWUW	BPA	Goodnoe Hills	WT	54	54	WND	2008	2008	11	T
COE	PSCO	Rawhide	ST	8	8	BIT	2008	2008	11	A
WY	WACM	Happy Jack	WT	29	29	WND	2008	2008	9	L
		Wind Derates		-543	-540					
		Additions for 2008		107	109					
NWUW	AVA	Noxon Rapids	HY	7	7	WAT	2010	2009	4	A
NWCB	BC Hydro	Gordon M Shrum	HY	30	30	WAT	2009	2009	4	T
NWCB	BC Hydro	Barr Creek	HY	1	2	WAT	2009	2009	5	L
NWCB	BC Hydro	Fries Creek	HY	1	5	WAT	2009	2009	5	L
NWCB	BC Hydro	Gold River Power	BM	85	81	OTH	2009	2009	9	L
NWCB	BC Hydro	Corrigan Creek	HY	<1	<1	WAT	2009	2009	10	L
NWCB	BC Hydro	English Creek	HY	3	0	WAT	2009	2009	10	L
NWCB	BC Hydro	Clint Creek	HY	1	1	WAT	2009	2009	11	L
NWCB	BC Hydro	Tamihi Creek	HY	3	1	WAT	2009	2009	11	L
NWCB	BC Hydro	Long Lake	HY	11	0	WAT	2009	2009	12	L
WY	PAC East	Naughton	ST	21	21	SUB	2009	2009	5	A
NM	PNM	Biomass	BM	32	32	WDS	2009	2009	3	T
		Additions for 2009		196	181					
AZ	APS	Cholla	ST	6	6	SUB	2010	2010	1	A
FCO	APS	Four Corners	ST	20	20	SUB	2010	2010	1	A
FCO	APS	Four Corners	ST	20	20	SUB	2010	2010	1	A
NWUW	AVA	Noxon Rapids	HY	7	7	WAT	2011	2010	4	A
NWCB	BC Hydro	Gordon M Shrum	HY	30	30	WAT	2010	2010	4	T
NWCB	BC Hydro	Gordon M Shrum	HY	30	30	WAT	2010	2010	4	T
NWCB	BC Hydro	Revelstoke	HY	500	500	WAT	1999	2010	10	L
UT	PAC East	Hunter	ST	19	19	BIT	2010	2010	5	A
UT	PAC East	Huntington	ST	18	18	BIT	2010	2010	12	A
WY	PAC West	Jim Bridger	ST	26	26	SUB	2010	2010	6	A
NVN	SPP	Battle Mtn	IC	-2	-2	DFO	2010	2010	12	RT
NVN	SPP	Battle Mtn	IC	-2	-2	DFO	2010	2010	12	RT
NVN	SPP	Battle Mtn	IC	-2	-2	DFO	2010	2010	12	RT
NVN	SPP	Battle Mtn	IC	-2	-2	DFO	2010	2010	12	RT
NVN	SPP	Brunswick	IC	-2	-2	DFO	2010	2010	12	RT
NVN	SPP	Brunswick	IC	-2	-2	DFO	2010	2010	12	RT
NVN	SPP	Brunswick	IC	-2	-2	DFO	2010	2010	12	RT
NVN	SPP	Valley Road	IC	-2	-2	DFO	2010	2010	12	RT
NVN	SPP	Valley Road	IC	-2	-2	DFO	2010	2010	12	RT
NVN	SPP	Steamboat 1	GE	-5	-5	GEO	2010	2010	12	RT
WY	WACM	WYGEN	ST	95	95	BIT	2010	2010	10	T
		Additions for 2010		750	748					
NWUW	AVA	Noxon Rapids	HY	7	7	WAT	2012	2011	4	A
UT	PAC East	Hunter	ST	12	12	BIT	2011	2011	5	A
UT	PAC East	Huntington	ST	18	18	BIT	2011	2011	12	A
WY	PAC East	Wyodak	ST	9	9	SUB	2011	2011	4	A
WY	PAC West	Jim Bridger	ST	26	26	SUB	2011	2011	5	A
WY	WACM	Dry Fork	ST	385	385	BIT	2011	2011	1	L
		Additions for 2011		457	457					
AZ	APS	Solana	SO	280	280	SUN	2012	2012	1	A
NWUW	AVA	Noxon Rapids	HY	7	7	WAT	2009	2012	4	A
UT	PAC East	Hunter	ST	19	19	BIT	2012	2012	4	A
WY	PAC East	Dave Johnston	ST	18	18	SUB	2012	2012	4	A
WY	PAC West	Jim Bridger	ST	26	26	SUB	2012	2012	6	A
		Additions for 2012		350	350					
WY	PAC West	Jim Bridger	ST	26	26	SUB	2013	2013	5	A
COE	WACM	Holcomb	ST	700	700	BIT	2012	2013	6	L
		Additions for 2013		726	726					

Class 4 Additions

Area	Balancing Authority	Name	Unit Type	Capacity MW Summer	Capacity MW Winter	Fuel Type	Commercial Operation Dates Original Year	Commercial Operation Dates Revised Year	Commercial Operation Dates Revised Month	Status
PGES	CISO	Morro Bay Repower	CC	1,200	1,200	NG	2008	2008	1	P
SCE	CISO	Walnut Creek I	GT	501	501	NG	2009	2008	8	P
WY	PAC East	Planned wind	WT	99	99	WND	2008	2008	12	P
		Wind Derates		-84	-84					
		Additions for 2008		1,716	1,716					
NWCA	AESO	Confidential Project	ST	53	53	SUB	2009	2009	9	P
NWUW	BPA	Biglow Canyon	WT	124	124	WND	2006	2009	10	P
SCE	CISO	Sun Valley	CC	500	500	NG	2009	2009	8	P
NM	EPE	Newman	GT	70	70	NG	2008	2009	6	P
NM	EPE	Newman	GT	70	70	NG	2009	2009	6	P
UT	PAC East	Milford Wind I	WT	200	200	WND	2009	2009	1	P
WY	PAC East	Planned wind	WT	99	99	WND	2009	2009	12	P
AZ	TEP	SGS Solar	PV	1	1	SUN	2007	2009	1	P
		Wind Derates		-369	-369					
		Additions for 2009		748	748					
NWCA	AESO	Confidential Project	GT	1,200	1,200	NG	2010	2010	6	P
UT	PAC East	Blundell	GE	35	35	GEO	2010	2010	1	P
UT	PAC East	CHP	OT	19	19	NG	2010	2010	1	P
AZ	TEP	SGS Solar	PV	1	1	SUN	2008	2010	1	P
		Additions for 2010		1,255	1,255					
SCE	CISO	El Segundo	CC	630	630	NG	2011	2011	6	P
NM	EPE	Newman	CT	70	70	NG	2010	2011	6	P
NM	EPE	Newman	CT	70	70	NG	2010	2011	6	P
LDWP	LDWP	Castaic	PS	20	20	WAT	2005	2011	1	P
SMUD	MID	Future Recip Plant	IC	8	8	NG	2011	2011	1	P
SMUD	MID	Future Recip Plant	IC	8	8	NG	2011	2011	1	P
SMUD	MID	Future Recip Plant	IC	8	8	NG	2011	2011	1	P
SMUD	MID	Future Recip Plant	IC	8	8	NG	2011	2011	1	P
SMUD	MID	Future Recip Plant	IC	8	8	NG	2011	2011	1	P
SMUD	MID	Future Recip Plant	IC	8	8	NG	2011	2011	1	P
NVN	SPP	Tracy	GT	-10	-11	DFO	2011	2011	12	RT
AZ	TEP	SGS Solar	PV	2	2	SUN	2009	2011	1	P
		Additions for 2011		830	829					
LDWP	LDWP	Haynes	ST	-281	-281	NG	2013	2012	1	RT
LDWP	LDWP	Haynes	ST	-202	-202	NG	2013	2012	1	RT
LDWP	LDWP	Haynes	CC	600	600	NG	2013	2012	1	P
AZ	TEP	Bowie	OT	600	600	BIT	2012	2012	1	P
AZ	TEP	SGS Solar	PV	1	1	SUN	2010	2012	1	P
		Additions for 2012		718	718					
NWUW	PAC West	Swift 1	HY	25	25	WAT	2013	2013	12	P
AZ	TEP	SGS Solar	PV	2	2	SUN	2011	2013	1	P
		Additions for 2013		27	27					
LDWP	LDWP	Scattergood	ST	-450	-450	NG	2014	2014	1	RT
LDWP	LDWP	Scattergood	CC	450	450	NG	2014	2014	1	P
NWUW	PAC West	Swift 1	HY	25	25	WAT	2014	2014	12	P
AZ	TEP	SGS Solar	PV	2	2	SUN	2012	2014	1	P
COE	WACM	Holcomb	ST	700	700	BIT	2013	2014	1	P
		Additions for 2014		727	727					
NVN	SPP	Ely EC	ST	750	750	BIT	2012	2015	6	P
NWUW	PAC West	Swift 1	HY	25	25	WAT	2015	2015	12	P
		Additions for 2015		775	775					
NVN	SPP	Ely EC	ST	750	750	BIT	2015	2016	6	P
		Additions for 2016		750	750					

Class 5 Additions

Area	Balancing Authority	Name	Unit Type	Capacity MW Summer	Capacity MW Winter	Fuel Type	Commercial Operation Dates Original Year	Commercial Operation Dates Revised Year	Commercial Operation Dates Revised Month	Status
NWCA	AESO	Northern Prairie	GT	99	99	NG	2008	2008	9	P
NWCA	AESO	Clover Bar Peaker	GT	100	100	NG	2008	2008	11	P
NWCA	AESO	Confidential Project	WT	99	99	WND	2008	2008	12	P
NWCA	AESO	Castle Rock Ridge	WT	112	112	WND	2008	2008	12	P
NWCA	AESO	Yagos Wind Farm	WT	100	100	WND	2008	2008	12	P
NWCA	AESO	Bluetrail Wind Farm	WT	66	66	WND	2008	2008	12	P
NWCA	AESO	Old Man River Wind	WT	47	47	WND	2008	2008	12	P
NWCA	AESO	River View Wind	WT	115	115	WND	2008	2008	12	P
NWCA	AESO	Confidential Project	WT	120	120	WND	2008	2008	12	P
NWCA	AESO	Confidential Project	WT	116	116	WND	2008	2008	12	P
NWCA	AESO	Confidential Project	WT	80	80	WND	2008	2008	12	P
NWCA	AESO	Confidential Project	WT	200	200	WND	2008	2008	12	P
NWCA	AESO	Confidential Project	WT	77	77	WND	2008	2008	12	P
NWCA	AESO	Confidential Project	WT	110	110	WND	2008	2008	12	P
NWCA	AESO	Confidential Project	WT	350	350	WND	2008	2008	12	P
NWCA	AESO	Confidential Project	WT	120	120	WND	2008	2008	12	P
NWCA	AESO	Waterton Wind Farm	WT	300	300	WND	2008	2008	12	P
NWCA	AESO	Summerview Ph.	WT	63	63	WND	2008	2008	12	P
NWCA	AESO	Confidential Project	WT	75	75	WND	2008	2008	12	P
NWCA	AESO	Confidential Project	WT	50	50	WND	2008	2008	12	P
NWCA	AESO	Confidential Project	WT	100	100	WND	2008	2008	12	P
NWCA	AESO	Confidential Project	WT	100	100	WND	2008	2008	12	P
NWCA	AESO	Confidential Project	WT	61	61	WND	2008	2008	12	P
NWCA	AESO	Confidential Project	WT	99	99	WND	2008	2008	12	P
NWCA	AESO	Confidential Project	WT	99	99	WND	2008	2008	12	P
NWCA	AESO	Confidential Project	WT	80	80	WND	2008	2008	12	P
NWCA	AESO	HWY 785 Wind Plant	WT	235	235	WND	2008	2008	12	P
NWUW	BPA	Nine Canyon III	WT	32	32	WND	2007	2008	1	P
NWUW	BPA	Big Horn Wind	WT	50	50	WND	2008	2008	6	P
NWUW	BPA	Combine Hills II	WT	63	63	WND	2006	2008	12	P
SCE	CISO	Desert Power	WT	63	63	WND	2008	2008	3	P
PGEP	CISO	S.F. ERG	GT	145	145	NG	2008	2008	6	P
PGEP	CISO	S.F. ERG derate	GT	-28	-28	NG	2008	2008	6	P
PGEN	CISO	Shiloh III	WT	200	200	WND	2008	2008	12	P
ID	IPC	Alkali Wind	WT	20	20	WND	2008	2008	5	P
		Wind Derates		-3,325	-3,325					
		Additions for 2008		392	392					
NWCA	AESO	Confidential Project	GT	97	97	NG	2009	2009	1	P
NWCA	AESO	Confidential Project	GT	110	110	NG	2009	2009	8	P
NWCA	AESO	Confidential Project	GT	95	95	NG	2009	2009	9	P
NWCA	AESO	Clover Bar Peaker	GT	100	100	NG	2009	2009	11	P
NWCA	AESO	Confidential Project	WT	75	75	WND	2009	2009	12	P
NWCA	AESO	Confidential Project	WT	99	99	WND	2009	2009	12	P
NWCA	AESO	Confidential Project	WT	71	71	WND	2009	2009	12	P
NWCA	AESO	Confidential Project	WT	99	99	WND	2009	2009	12	P
NWCA	AESO	Confidential Project	WT	80	80	WND	2009	2009	12	P
NWCA	AESO	Confidential Project	WT	15	15	WND	2009	2009	12	P
NWCA	AESO	Confidential Project	WT	60	60	WND	2009	2009	12	P
NWCA	AESO	Confidential Project	WT	30	30	WND	2009	2009	12	P
NWCA	AESO	Joss Wind-Hand Hill	WT	80	80	WND	2009	2009	12	P
NWUW	BPA	Kittitas Valley	WT	108	108	WND	2009	2009	8	P
NWUW	BPA	Reardon Twin Buttes	WT	75	75	WND	2009	2009	10	P
NWUW	BPA	Big Horn Wind	WT	150	150	WND	2009	2009	12	P
NWUW	BPA	Seven Mile Hill	WT	50	50	WND	2006	2009	12	P
MXW	CFE	Baja California II	CC	223	223	NG	2009	2009	4	P
PGES	CISO	S. Kern Front CG	GT	94	94	NG	2009	2009	1	P
PGES	CISO	Liberty V Lost Hills	BM	20	20	SLW	2009	2009	8	P
ID	IPC	Oregon Trails	WT	11	11	WND	2006	2009	1	P
ID	IPC	Pilgrim Stage	WT	11	11	WND	2006	2009	1	P
ID	IPC	Thousand Springs	WT	11	11	WND	2006	2009	1	P
ID	IPC	Tuana Gulch	WT	11	11	WND	2006	2009	1	P
ID	IPC	Burley Butte	WT	11	11	WND	2006	2009	1	P
ID	IPC	Milner Dam	WT	18	18	WND	2007	2009	1	P
ID	IPC	Magic Wind	WT	20	20	WND	2007	2009	1	P
ID	IPC	Golden Valley	WT	11	11	WND	2007	2009	1	P
ID	IPC	Lava Beds	WT	18	18	WND	2006	2009	1	P
ID	IPC	Notch Butte	WT	18	18	WND	2006	2009	1	P

Class 5 Additions

Area	Balancing Authority	Name	Unit Type	Capacity MW Summer	Capacity MW Winter	Fuel Type	Commercial Operation Dates Original Year	Commercial Operation Dates Revised Year	Commercial Operation Dates Revised Month	Status
ID	IPC	Salmon Falls	WT	21	21	WND	2007	2009	1	P
SMUD	MID	Countryside	GT	4	4	NG	2009	2009	1	P
SMUD	MID	Woodland	GT	-44	-47	NG	2009	2009	11	RT
NM	PNM	Delta Person	CA	72	72	NG	2009	2009	6	P
		Wind Derates		-1,085	-1,085					
		Additions for 2009		838	835					
NWCA	AESO	Confidential Project	GT	180	180	NG	2010	2010	1	P
NWCA	AESO	Confidential Project	WT	700	700	WND	2010	2010	12	P
NWCA	AESO	Stirling Wind Farm	WT	100	100	WND	2010	2010	12	P
NWCA	AESO	Confidential Project	WT	200	200	WND	2010	2010	12	P
NWCA	AESO	Confidential Project	WT	80	80	WND	2010	2010	12	P
NWCA	AESO	Greengate Wint. Hill	WT	150	150	WND	2010	2010	12	P
NWCA	AESO	Confidential Project	WT	150	150	WND	2010	2010	12	P
NWCA	AESO	Confidential Project	WT	300	300	WND	2010	2010	12	P
NWCB	BC Hydro	Anyox & Kitsault R	HY	40	6	WAT	2010	2010	1	P
NWCB	BC Hydro	Mackenzie Green EC	BM	50	45	WDS	2010	2010	4	P
NWCB	BC Hydro	Spuzzum Creek	HY	1	5	WAT	2010	2010	4	P
NWCB	BC Hydro	Songhees Creek Hydro	HY	1	8	WAT	2010	2010	5	P
NWCB	BC Hydro	Victoria Lake Hydro	HY	1	5	WAT	2010	2010	5	P
NWCB	BC Hydro	Princeton Power	OT	48	48	OTH	2010	2010	7	P
NWCB	BC Hydro	Mkw'alts Ck	HY	20	5	WAT	2010	2010	9	P
NWCB	BC Hydro	Ucona River	HY	5	13	WAT	2010	2010	10	P
NWCB	BC Hydro	Glacier/Howser	HY	24	1	WAT	2010	2010	11	P
NWCB	BC Hydro	Glacier/Howser	HY	24	1	WAT	2010	2010	11	P
NWCB	BC Hydro	Kookipi Creek	HY	1	1	WAT	2010	2010	11	P
NWCB	BC Hydro	Kwoiek Creek	HY	22	5	WAT	2010	2010	11	P
NWCB	BC Hydro	Log Creek	HY	3	1	WAT	2010	2010	11	P
NWCB	BC Hydro	Sakwi Creek RoR	HY	1	0	WAT	2010	2010	11	P
NWCB	BC Hydro	Tyson Creek	HY	7	0	WAT	2010	2010	11	P
NWUW	BPA	Shepards Flat	WT	250	250	WND	2009	2010	10	P
PGEN	CISO	CPV Colusa	CC	715	715	NG	2009	2010	1	P
PGEN	CISO	Russell City	GT	361	361	NG	2009	2010	6	P
PGES	CISO	Tesla Sub	CC	1,156	1,156	NG	2008	2010	12	P
IID	IID	Unidentified	GE	20	20	GEO	2009	2010	1	P
IID	IID	Hudson Ranch	GE	49	49	GEO	2010	2010	3	P
LDWP	LDWP	Renewable Project	BM	23	23	MSW	2010	2010	12	P
LDWP	LDWP	Renewable Project	HY	3	3	WAT	2010	2010	12	P
SMUD	MID	Woodland	CT	-36	-46	NG	2010	2010	4	RP
SMUD	MID	Woodland	CA	-37	-37	NG	2010	2010	4	RP
SMUD	MID	Woodland	CT	36	46	NG	2010	2010	4	RP
SMUD	MID	Woodland	CT	23	33	NG	2010	2010	4	RP
SMUD	MID	Woodland	CA	37	37	NG	2010	2010	4	RP
NVS	NPC	Clark	GT	-54	-63	NG	2010	2010	10	RT
WY	PAC East	Planned wind	WT	99	99	WND	2010	2010	12	P
NWUW	PAC West	Planned wind	WT	198	198	WND	2010	2010	12	P
AZ	TEP	Unidentified	GT	150	150	NG	2008	2010	6	P
		Wind Derates		-2,144	-2,144					
		Additions for 2010		2,956	2,854					
MXW	CFE	Baja California III	CC	288	288	NG	2011	2011	4	P
PGEN	CISO	Montezuma	WT	38	38	WND	2008	2011	12	P
NM	EPE	LMS-1	GT	86	86	NG	2011	2011	2	P
IID	IID	Niland	GT	45	45	NG	2011	2011	5	P
IID	IID	Niland	GT	45	45	NG	2011	2011	5	P
IID	IID	Niland	GT	45	45	NG	2011	2011	5	P
IID	IID	Niland	GT	45	45	NG	2011	2011	5	P
LDWP	LDWP	Renewable Project	BM	23	23	MSW	2011	2011	12	P
MT	NWMT	Highwood	ST	268	268	LIG	2009	2011	11	P
WY	PAC East	Planned wind	WT	198	198	WND	2011	2011	12	P
SMUD	SMUD	Solano Wind	WT	105	105	WND	2009	2011	7	P
		Wind Derates		-243	-286					
		Additions for 2011		943	900					
SCE	CISO	Green Borders	GE	62	62	GEO	2011	2012	2	P
PGES	CISO	Planned Lodi	CC	250	250	NG	2012	2012	8	P
IID	IID	El Centro	ST	-80	-80	RFO	2009	2012	5	RT
LDWP	LDWP	Renewable Project	BM	23	23	MSW	2012	2012	12	P

Class 5 Additions

Area	Balancing Authority	Name	Unit Type	Capacity MW Summer	Capacity MW Winter	Fuel Type	Commercial Operation Dates Original Year	Commercial Operation Dates Revised Year	Commercial Operation Dates Revised Month	Status
LDWP	LDWP	Renewable Project	BM	4	4	OBG	2012	2012	7	P
LDWP	LDWP	Renewable Project	HY	2	2	WAT	2012	2012	4	P
NVS	NPC	Reid Gardner	ST	-105	-105	BIT	2012	2012	10	RT
NVS	NPC	Reid Gardner	ST	-105	-105	BIT	2012	2012	10	RT
NVS	NPC	Reid Gardner	ST	-105	-105	BIT	2012	2012	10	RT
UT	PAC East	CCCT F 2x1 w/DF	CT	132	140	NG	2012	2012	1	P
UT	PAC East	CCCT F 2x1 w/DF	CT	132	140	NG	2012	2012	1	P
UT	PAC East	CCCT F 2x1 w/DF	CA	234	232	NG	2012	2012	1	P
UT	PAC East	CCCT F 2x1 w/DF	CT	139	143	NG	2012	2012	1	P
UT	PAC East	CCCT F 2x1 w/DF	CT	139	143	NG	2012	2012	1	P
UT	PAC East	CCCT F 2x1 w/DF	CA	239	238	NG	2012	2012	1	P
NWUW	PAC West	Planned wind	WT	99	99	WND	2012	2012	12	P
		Wind Derates		-84	-84					
		Additions for 2012		977	997					
MXW	CFE	Baja California IV	CC	288	288	NG	2012	2013	4	P
PGES	CISO	Wellhead McCall	GT	300	300	NG	2008	2013	3	P
LDWP	LDWP	Renewable Project	BM	23	23	MSW	2013	2013	12	P
UT	PAC East	Planned wind	WT	198	198	WND	2013	2013	12	P
NVN	SPP	Tracy	ST	-53	-53	NG	2013	2013	12	RT
NVN	SPP	Tracy	GT	-10	-11	DFO	2013	2013	12	RT
AZ	TEP	Unidentified	GT	150	150	NG	2010	2013	6	P
		Wind Derates		-168	-168					
		Additions for 2013		728	727					
IID	IID	Calipatria	GE	5	5	GEO	2014	2014	1	P
IID	IID	El Centro	CA	80	80	NG	2009	2014	5	P
IID	IID	El Centro	CT	170	170	NG	2009	2014	5	P
		Additions for 2014		255	255					
NM	EPE	Newman	GT	70	70	NG	2013	2015	6	P
SMUD	SMUD	Iowa Hill	PS	390	390	WAT	2014	2015	7	P
NVN	SPP	Tracy	ST	-83	-83	NG	2015	2015	12	RT
		Additions for 2015		377	377					
NM	EPE	Newman	GT	70	70	NG	2016	2016	6	P
NVS	NPC	Sunrise	ST	-80	-82	NG	2016	2016	10	RT
NVS	NPC	Sunrise	GT	-70	-81	NG	2016	2016	10	RT
		Additions for 2016		-80	-93					
NM	EPE	Newman	CA	148	148	NG	2014	2017	2	P
IID	IID	Niland	GT	45	45	NG	2017	2017	5	P
IID	IID	Niland	GT	45	45	NG	2017	2017	5	P
IID	IID	Niland	GT	45	45	NG	2017	2017	5	P
IID	IID	Niland	GT	45	45	NG	2017	2017	5	P
LDWP	LDWP	Renewable Project	PV	270	270	SUN	2017	2017	12	P
		Additions for 2017		598	598					

Definitions of Generation Addition Codes

UNIT TYPE

HY	Hydro – Conventional
PS	Hydro – Pumped Storage
ST	Steam Turbine – Non-Nuclear
NP	Steam Turbine – Nuclear
GT	Combustion Turbine
CA	Combined Cycle – Steam Portion
CT	Combined Cycle – Combustion Turbine Portion
CS	Combined Cycle – Single Shaft
CC	Combined Cycle – Total Unit
GE	Geothermal
IC	Internal Combustion
FC	Fuel Cell
BM	Biomass
PV	Solar Power – Photovoltaic
SP	Solar Power – Thermal
SO	Solar Power – Other
WT	Wind Power
CE	Compressed Air Energy Storage

FUEL TYPE

BIT	Bituminous Coal
SUB	Sub-Bituminous Coal
LIG	Lignite Coal
WC	Waste Coal
SC	Synthetic Coal-based Fuel
PC	Petroleum Coke
DFO	Distillate Fuel Oil
JF	Jet Fuel
KER	Kerosene
RFO	Residual Fuel oil
WO	Waste Oil
NG	Natural Gas
PG	Propane
BFG	Blast Furnace Gas
OG	Other Gas (coke oven, refinery, etc.)
NUC	Nuclear
GEO	Geothermal Steam
WAT	Water-base ratings on median hydro conditions
AB	Agriculture Crop Byproducts
BLQ	Black Liquor
LFG	Landfill Gas
MSW	Municipal Solid Waste
OBL	Other Biomass Liquids
OBS	Other Biomass Solids
OBG	Other Biomass Gases (methane)
PUR	Purchased Steam

FUEL TYPE (Continued)

SLW Sludge Waste
TDF Tires
WDL Wood or Wood Waste, Liquid
WDS Wood or Wood Waste, Solid
SUN Sun
WND Wind

STATUS CODE (As reported in the data submittal and as classified by LRS for the PSA)

Class 1 Status Codes

U Under active construction, less than or equal to 50% complete (based on construction time to first electric date)
V Under active construction, more than 50% complete (based on construction time to first electric date)
TS Construction complete, but not yet in commercial operation (including low power testing of nuclear units)
A Generator capability increased (re-rated or relicensed)
D Generator capability decreased (re-rated or relicensed)
M Generator to be put in deactivated shutdown status
RA Previously retired or deactivated generator planned for reactivation
RT Existing generator scheduled for retirement
FC Existing generator planned for conversion to another fuel or energy source
RP Proposed for life extension or repowering
CO Change of ownership (including change of shares of jointly-owned units)

Class 2 and Class 3 Status Codes

L Regulatory approval pending but not under active construction (started site preparation)
T Regulatory approval received but not under active construction
A Generator capability increased (re-rated or relicensed) (Beyond Class 1 Timeframe)
D Generator capability decreased (re-rated or relicensed) (Beyond Class 1 Timeframe)
RT Existing generator scheduled for retirement

Class 4 and Class 5 Status Codes

P Planned for installation but not under active construction
RT Existing generator scheduled for retirement
RP Proposed for life extension or repowering
A Generator capability increased (re-rated or relicensed)
D Generator capability decreased (re-rated or relicensed)

Market Analysis

Prepared
For

FORTISBC

By

Willis
ENERGY SERVICES LTD.

August 27, 2007

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Glossary

Alberta Pool Price: The market price for electricity as published by the Alberta Electric System Operator (AESO) on their internet site www.aeso.ca.

Call Option: A transaction where one party obtains the right to purchase a specified amount of a commodity at a specific time in the future or over a specific time period. The right may have a price associated with it or it may not.

Capacity:
(1) The instantaneous power output at any given time, normally measured in kilowatts (kW) or megawatts (MW), of a power plant.
(2) The instantaneous electricity demand at any given time, normally measured in kilowatts (kW) or megawatts (MW).
(3) A transmission facility's ability to transmit electricity, at any instant.

Capacity Purchase: The purchase of capacity without energy.

Day-Ahead Purchases: The term refers to commodity purchases made one day ahead of the time when possession of the commodity is obtained.

Discount Rate: A rate used to determine the present value of expenses and revenues that will occur over a period of time, reflecting the cost of capital.

Energy: The electricity produced or used over a period of time, usually measured in kWh, MWh or GWh.

Energy Block: A purchase of a monthly or longer block of market power (generally heavy load hours November through February) required to meet customer load.

Firm Market Purchase: The highest degree of reliable market power that can be purchased. It can only be curtailed due to the most severe contingencies such as the loss of the transmission path. See also Long-Term Firm Resource.

Gigajoule (GJ): A unit of energy equal to 277.8 kWh, or 947,000 British Thermal Units.

Gigawatt-Hour (GWh): One billion watt hours; one million kilowatt hours (an amount of electric energy that will serve about 100 residential customers for one year).

Greenhouse Gases (GHG): Gases that are thought to contribute to global climate change, or the greenhouse effect, including carbon dioxide (CO2), carbon monoxide (CO) and methane (CH4).

Heavy Load Hours (HLH): Heavy Load Hours are from 0600h through 2200h, Monday to Saturday, excluding holidays.

Hedge: This term used in this report refers to a transaction where the future price for a commodity is fixed or partially fixed.

Kilowatt (kW): One thousand watts; the commercial unit of measurement of electric power. A kilowatt is the flow of electricity required to light ten 100-watt light bulbs.

Kilowatt Hour (kWh): One thousand watts used for a period of one hour; the basic unit of measurement of electric energy. On average, residential customers in British Columbia use about 10,000 kWh per year.

Levelized Cost, Levelized Price:
Levelizing is a method of converting a non-

uniform stream of energy costs (or prices) into a present value equivalent uniform cost (or price).

Light Load Hours (LLH): All hours that are not Heavy Load Hours. See Heavy Load Hours.

Load: The amount of electricity required by a customer or group of customers.

Load Forecast: The expected load requirements that an electricity system will have to meet in the future.

Load Duration Curve: The variation in electrical load over time, usually hour-by-hour for a month or a year. The curve is sorted with the highest load over the period in question first followed by the next highest load and so on. This provides an effective way to determine how many hours loads exceeded a certain level.

Market: The network of electricity trading options that allows the purchase of wholesale electricity.

Market Volatility: Market prices vary considerably depending on the time of day, weather, fuel costs, and regional resource availability. This leads to potential market price shock risk.

Medium-Term Purchase: Energy Block market purchases made three to five years in advance.

Megawatt (MW): One million watts; one thousand kilowatts. A unit commonly used to measure both the capacity of generating stations and the rate at which energy can be delivered.

Megawatt Hour (MWh): 1,000 kWh.

Mid-C: The mid-Columbia electricity region.

Mid-C Index: A value published by Dow Jones which involves surveying buyers and sellers of electricity at Mid-C to determine actual transaction costs. The Mid-C index is issued for several types of purchases, including daily LLH and HLH transactions.

NWPP: Northwest Power Pool.

Off-Peak: See Light Load Hours.

Peaking Plant: A generation plant that typically only runs at times of peak demand. See also Super-Peaking.

Power: The instantaneous rate at which electrical energy is produced, transmitted or consumed, typically measured in watts (W), kilowatts (kW), or megawatts (MW). See also Capacity.

Present Value (PV): Today's discounted value of future receipts or expenditures. Often also called net present value. See also Discount Rate.

Real-Time Purchases: The term refers to commodity purchases made at the same time when possession of the commodity is obtained.

Reliability: A measure of the adequacy and security of electric service. Adequacy refers to the existence of sufficient facilities in the system to satisfy the load demand and system operational constraints. Security

refers to the system's ability to respond to transient disturbances in the system.

Reserve: System generating capacity beyond that required to meet peak demand, ensuring sufficient generation is available if some generating units are not available;

necessary to meet reliability criteria for planning and operation.

Resource: A source of electricity that is available to help meet or reduce electricity demand, including generation, purchases, demand-side management and transmission facilities.

Short-Term Purchase: Energy Block market purchases made several months, up to a year, in advance.

Spark Spread: The price of electricity in $/MWh divided by the price of natural gas in $/GJ.

Spot Market: Real-time (hourly) and day-ahead market purchases and sales of electricity.

Super-Peak Period: Hours between 1800h and 2100h Monday to Saturday, excluding holidays.

Take or Pay Contract: A contract where a buyer agrees to pay for the delivery of a specified amount of a commodity at specified times regardless of whether delivery actually occurs.

Watt: The basic unit of measurement of electric power, indicating the rate at which electric energy is generated or consumed. (1 watt=1 joule per second).

Watthour (Wh): An electrical energy unit of measure equal to one watt of power supplied to, or taken from, an electric circuit steadily for one hour.

WECC: Western Electricity Coordinating Council

1. Introduction

FortisBC Inc. (FortisBC) purchases power from the market on a real-time basis and on a short to medium-term basis (3 months to five years). This Market Analysis was prepared for FortisBC by Willis Energy Services Ltd. to assist in reviewing a market purchasing strategy.

2. Power Market Context

An important part of a Market Analysis is the overall market context including a description of the available supply sources, the transmission constraints and the fundamentals that affect pricing.

The FortisBC service territory is part of the Western Electricity Coordinating Council (WECC) region, an area that covers 14 western U.S. States and the provinces of Alberta and British Columbia. The wholesale electricity market in this area involves transactions between utilities, independent power producers (IPPs) and power marketers that operate within the region.

2.1. Supply Sources Available to Market

Most of the power generation in British Columbia, Alberta and the U.S. Pacific Northwest is either owned by utilities or committed by contracts to supplying utilities. As such, most of the electric power generated is not available to the wholesale market. Energy and capacity that does become available to the wholesale market is available for the following reasons:

- Surplus power is available from hydroelectric plants during the spring freshet or on an annual basis during years of above average precipitation.
- Capacity and energy is available from some gas generation projects.
- Operators of large coal fired and nuclear facilities prefer to operate them on a base load basis; therefore surplus power from these facilities is usually available during off-peak hours.
- Various utilities will have surplus power available from time to time from their generation system because their own load is not as high as forecast.
- Some utilities, BC Hydro is the most prominent, can store energy and capacity in their hydro-electric resources and are able usually to provide power to the market for the right price or purchase power from the market at the right price.[1]

It is important to note that the electricity market at the present time is significantly different than other energy commodity markets like oil and natural gas. The development of new oil sources and natural gas sources is very much influenced by market prices, so that high fuel prices stimulate exploration activity and encourage a reduction in consumption. However

[1] BC Hydro, 2006 Integrated Electricity Plan, Application to the British Columbia Utilities Commission

due to the control that the large utilities have on the generation in the region and due to the strong regulation on electricity prices, new generation is usually only built after a long-term supply contract has been obtained from a utility.

This characteristic of the electricity market can cause extreme volatility in market prices because situations can occur where most of the utilities in the region are in a deficit position, in which case very inefficient and costly gas fired plants have to be brought into service. In the other extreme situation, most of the utilities in the region may have a surplus such as in a high spring freshet period in which case there may be no place for the power to go. Market electricity prices have varied over the last six years from extremely low values (US$0.25 per MWh off-peak, June 18, 2006) to extremely high values of US$559.40 $/MWh (January 20, 2001)[2].

Care should be taken in relying on the wholesale electricity market. For most commodities, market economics will reduce the likelihood of shortages. High prices will cause a reduction in consumption and at the same time encourage new supply to become available. In general these same market economics are not at play in the electricity market. In a shortage situation, consumers are not influenced to reduce consumption because of high prices and mechanisms are not available for new supply to readily enter the market. Accordingly, there is a significant risk of shortages if utility planners rely too heavily on the wholesale electricity market.

2.2. Transmission Considerations

Transmission capacity is a very important consideration with respect to buying or selling from the wholesale market. The rules of the U.S. Federal Energy Regulatory Commission (FERC) require all utilities who want to participate in the wholesale market to establish tariffs for power to be wheeled through their systems[3]. However, the transmission systems are built to serve firm load and there can be insufficient transmission capacity available to wheel power on a short-term basis to serve market transactions.

Just as with generation, transmission lines are not built to serve transactions in the wholesale market. Transmission capacity is usually available because transmission systems are built to handle the most severe firm load conditions. For example, BC Hydro's transmission system is built to supply power to the Lower Mainland on the coldest day of the year and accordingly on most days spare capacity will be available[4]. However, as wholesale trade continues to expand conditions will become more frequent when transmission capacity will limit or prevent power to be wheeled from one jurisdiction to another.

A key consideration for FortisBC, with respect to making market purchases are the transfer limits at the BC/U.S. border and at the Alberta/BC border.

[2] Willis Energy Services: US$ 0.25/MWh; CAN$ 0.28/MWh (June 18, 2006); US$ 559.40/MWh; CAN$ 846.76/MWh (January 20, 2001).
[3] Federal Energy Regulatory Corporation Commission (FERC), Order No.888. Open Access Transmission Tariff.
[4] British Columbia Transmission Corporation – Web site, Control Area Load Data

For the BC/U.S. border the transfer limit north into BC is 2,000 MW and south is 3,150 MW. Transfer limits are based on a number of factors and these limits consider the combined capability of the two 500 kV lines, near Vancouver between BC Hydro's Ingledow sub-station and Bonneville Power Authority's Custer sub-station and the two 230 kV lines near Trail between Boundary and Nelway. The Boundary-Nelway line must not exceed 400 MW in either direction due to the 400 MVA limit on a phase shifting transformer at Nelway.

It is important to note that the BC/US transfer limit is a combination of transfer points and that British Columbia Transmission Corporation (BCTC) controls this transfer. Individual system characteristics of BC Hydro and Washington state grids limit the amount of power that can be transferred between the two systems, ultimately limiting the market transactions that can occur

There are two 138 kV lines and one 500 kV lines connecting the Alberta and BC Hydro integrated systems. The Total Transfer Limit from Alberta to BC is 450 MW while the limit from BC to Alberta is 545 MW[5]. There are however a number of system conditions which reduce these limits at specific times.

It should be noted that both the Alberta-BC interconnection and the BC-US interconnection are often at their maximum limits and wheeling transactions between utilities in the region are prevented by these limits. As the power generation and power demand in the region continues to grow the transfer constraints will become more severe.

2.3. Planning and Operating Margins

In order to maintain the stability of large integrated utility networks, coordinating bodies like the Western Electricity Coordinating Council (WECC) require their members to maintain margins between the load levels on their systems and the generating capability of their systems. The purpose of these margins is to prevent system wide collapse if generation unexpectedly drops off line.

FortisBC does not have adequate operating margin within its own system for a significant number of hours during the year. They obtain the required margin by contracting for capacity from utilities outside their jurisdiction and from Teck-Cominco. This practice is acceptable to the Western Electricity Coordinating Council.

FortisBC also is part of the Northwest Power Pool and is part of their Automated Reserve Sharing arrangement whereby the members can essentially share operating reserve. This practice is also an acceptable procedure for maintaining acceptable margins.

However, it is important to note that on a long-term (greater than 3-years) basis, the ability to contract with other utilities for this adequate margin is going to be more difficult because margins and surplus generation of these other utilities is being reduced. Note BC Hydro's supply gap, per BC Hydro's 2006 Integrated Electricity Plan.

[5] British Columbia Transmission Corporation – Web site, Control Area Load Data

2.4. Fundamentals of Market Pricing

While reviewing historical wholesale electricity prices and forecasting future prices, the following market fundamentals should be considered:

2.4.1. Precipitation

32.2 percent of the generating capacity in the WECC is hydroelectric[6] and variations in annual precipitation can cause significant variations from year to year in the energy that is available in the area. The energy available from BC Hydro's hydroelectric resources varies from 36,462 GWh in the driest year to 55,856 GWh in the wettest year[7].

There are a number of distinct weather regions within the total WECC area and accordingly, the amount of hydro power in any year can vary from region to region. If a region experiences a high precipitation year, they will most likely have surplus power available for the wholesale market. If they have a low precipitation year they will probably need to purchase power from the market. BC Hydro with their current supply-demand balance on an average water year will need to purchase from the market, however, on a high water year they would have a net surplus to sell to the market.

2.4.2. Gas Price

39.0 percent of the generating capacity in the WECC[8] is from gas fired generating plants. In general these plants are the last plants within the resource stack to come on line. In other words the hydroelectric resources are used first followed by the nuclear plants and the coal fired facilities. After these facilities are on line the gas-fired plants are brought into service so that supply matches the demand. At most times, spare gas-fired plant capacity is not fully utilized and a utility or an IPP can bring additional capacity into service to supply the market.

The decision as to whether a plant owner uses such a facility to supply the market will depend on the price of natural gas and the efficiency or heat rate of the plant involved. The table below indicates the fuel component cost of the most efficient and least efficient gas fired plants. At a gas price of $6.00 per GJ, the fuel component of the cost of electricity from combined cycle gas fired plant is $43.20 per MWh.

Table 1 - Fuel Component of Cost of Electricity from Gas Fired Generating Plants ($/MWh)

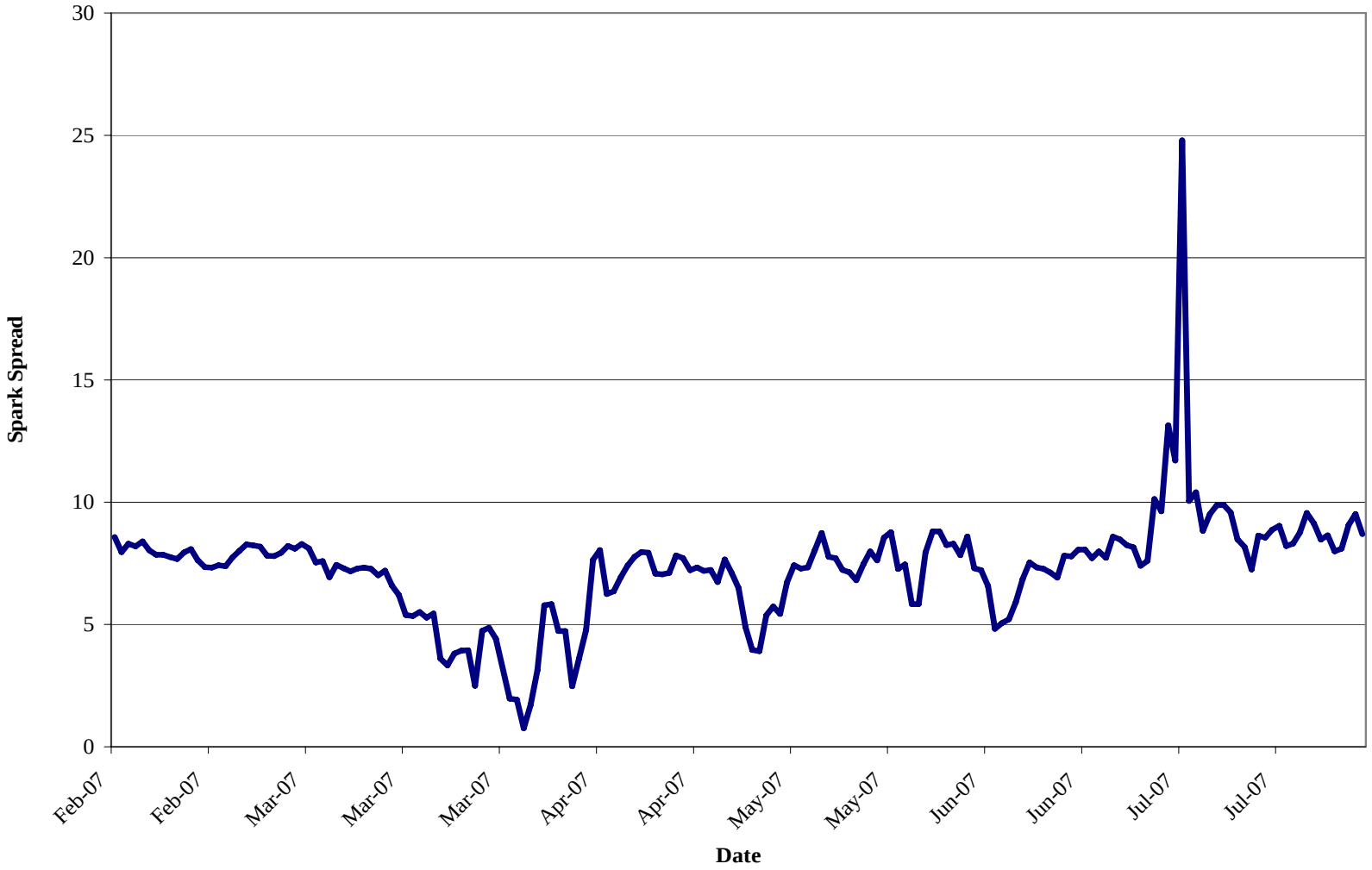
[6] WECC, 2006. WECC 10-Year Coordinated Plan Summary – July 2006, Figure 3.
[7] BC Hydro, 1997. BC Hydro Power Supply Operations – Annual Review 1996/97
[8] WECC, 2006. WECC 10-Year Coordinated Plan Summary – July 2006, Figure 3.

Natural Gas Price, $/GJ	Most Efficiency Gas Fired Combined Cycle Plants – Fuel Component $/MWh	Older Generation Gas Fired Steam Cycle Units – Fuel Component $/MWh
$ 4.00	$ 28.80	$ 44.00
$ 6.00	$ 43.20	$ 66.00
$ 8.00	$ 57.60	$ 88.00

In addition to the fuel component of operating a gas fired plant, there are additional non-fuel operating and maintenance costs. Overhaul periods and costs for example, are dependent on operating hours. One method for reviewing historically as to when owners are going to react to gas price and electricity market prices is to record the "spark spread" or the market price of electricity in $/MWh divided by the price of gas in $/GJ. The graph below indicates the spark spread in the Pacific Northwest over the last six months.

The average spark spread over this period was 7.27, which means that on the average for this period for a gas price of $7.00 per GJ, the market electricity price was 7.27 x 7 = $50.89 per MWh.

Figure 1 - Daily Spark Spread in the Pacific Northwest



Source: Willis Excel Calculation Workbook Prepared for Market Analysis Report, Aug 24 2007.

The peak in July indicated that the demand for supply most likely exceeded the gas fired capacity that could be readily brought on line, while the sharp drop in April indicated that there was so much hydro power available that all the gas fired plants would be shut-down except those with take or pay contracts.

The spark spread is a key fundamental of the electricity market and connects the market price of gas with the wholesale electricity price.

2.4.3. Coal and Nuclear Facilities

Operators of these types of facilities prefer to operate these units under a base load condition. Accordingly for some utilities during off-peak hours, the supply from these units is more than their demand and they will try to sell the surplus power to the market at what ever price they can get. The major utilities in Alberta are in this position, and the extent to which they are willing to lower their sell price in order to keep their units operating is demonstrated by the Alberta Pool Price during off-peak hours; it often goes below $10.00 per MWh.

These units can also have an impact on the market when they go out of service due to their unit size which is as large as 750 MW. If a 750 MW unit is taken out of service unexpectedly it can have a significant impact on the market.

2.4.4. Demand from Energy Intense Industry

In the states of Oregon and Washington and in British Columbia due to the availability of low-cost hydro power over the last 40 years, there is a significant amount of energy intense industry such as the following:

- Aluminum smelters
- Zinc smelters
- Electro-chemical plants
- Pulp and Paper mills.

These facilities have been built on a basis of low electricity costs and in many cases cannot produce competitively priced product, if they have to pay the cost of power from new generation sources. Electricity prices are regulated and these types of plants either have their own power sources or access to low-cost regulated prices from utilities. However, as utilities gradually have to raise rates to accommodate the cost of new high priced generation, some of these plants will most likely shut down. From 1999 to 2003, approximately 2,000 MW of aluminum plant power demand was taken out of service in Oregon and Washington. When such facilities are taken out of service, additional power is made available for the market.

In high price periods, these types of power customers can also be readily encouraged to shutdown for short periods, making their demand available for the market. In fact almost all of the energy intense customers in BC have shut-down or curtailed at one time or another in order to be compensated for releasing their demand to the market[9].

2.4.5. Uncertain Load Growth and Planning Margin

It is impractical for a utility to forecast exactly the load growth within its service territory. Therefore any utility will have a surplus to sell to the market or a deficit requiring purchases from the market, depending on whether its forecast growth is above or below the actual growth. In predicting market prices, a key fundamental is economic activity in the region, if GDP and population growth is higher than expected, it is reasonable to assume that many utilities will have forecast a lower growth rate than what actually occurs. In the case of an economic recession the opposite is most likely true.

2.4.6. Marginal Cost of New Supply

A key market fundamental is the cost of new supply. BC Hydro's 2006 Call for Power provides good information in this regard[10]. Although the cost of new supply is not directly related to the real-time market price, it is a reference point. If for example the real-time price is much higher than the cost of new supply, power sellers realize that the price at some time will fall and they are more likely to accept long-term contracts at prices below the real-time price. However, if the real-time price is much lower than the cost of new supply sellers will be much less likely to commit to long-term contracts because they realize that prices will eventually need to rise.

The table below[11] indicates the cost of new supply based on bids to BC Hydro and to Puget Sound Energy. The average price for the firm power purchased in BC Hydro's 2006 CFT was $87.50 per MWh (On a levelized basis in 2006$). It is Willis' belief that these costs are lower than today's cost due to continuing escalating construction costs as well the significant increase in permitting problems with coal-fired and gas-fired generation facilities.

Table 2 Cost of New Electricity Supply (BC Hydro and Puget Sound Bids)

Levelized Plant Gate Prices	PSE – 2006 RFP		BC Hydro – F2006 Call
	US$/MWh	Cdn.$/MWh*	(Cdn.$/MWh)
Wind	76 – 106	84 – 118	71 – 91
Natural Gas	70 – 129	78 – 143	n/a
Coal	71 – 125	79 – 139	67 – 82
Hydro	59 – 100	66 – 111	56 – 95
PPAs	61 – 101	68 – 112	n/a

* Assuming a Canada/US exchange rate of $0.90

[9] Willis Energy Services Ltd, confidential client information (2007).
[10] BC Hydro, 2006. Report in the Call for Tender Process Conducted by BC Hydro - Aug 31, 2006.
[11] BC Hydro, 2006. Report in the Call for Tender Process Conducted by BC Hydro - Aug 31, 2006.

Further relevant information on this subject is that as of 2011, customers of Bonneville Power Administration (BPA), the major hydro-electric supplier in the U.S. pacific northwest will have to go to the market for 20 to 30 percent of their needs. To compound the situation, they will be required per state legislation to acquire most of this supply from renewable sources. This is expected to provide a significant upward pressure on prices for new supply.

2.5. Historical Market Information

2.5.1. Short Term Forward Purchases versus Spot Market

The short-term (three months to one year) forward electricity price market is quite liquid (significant number of transactions occurring) so that considerable information is available on the price of short-term forward purchases versus spot-market purchases. As part of this study, Mid-C firm spot-market or real-time purchases were compared with electricity purchases made three months, six months and one year in advance of actual delivery. The table below compares spot prices (Mid-C Real-time prices) with prices for purchases made in advance[12]. The graph on the following page is a plot of data for the six-year period. The graph itself is somewhat confusing; however, the following sections will analyze different sections of the graph further.

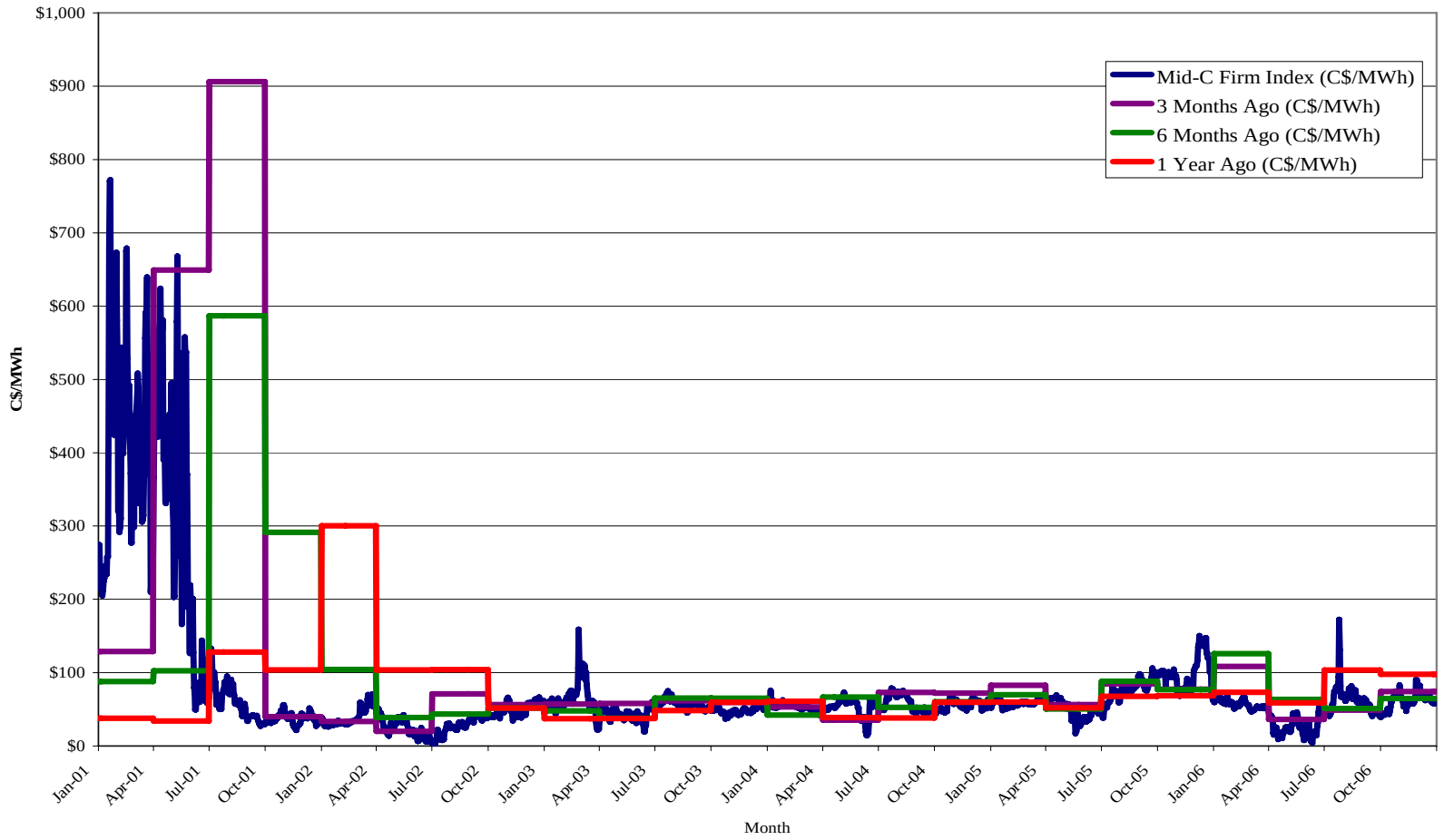
Table 3 - Mid-C Daily Index vs. Forward Prices, C$/MWh
(January 2001 to December 2006)

Average Mid-C Price Over Period	Average Price if Power Purchased Three Months in Advance	Average Price if Power Purchased Six Months in Advance	Average Price if Power Purchased One Year in Advance
$77.62	$122.80	$97.44	$75.95

The total six-year data indicates that further ahead purchases are made the smaller the premium for forward purchases. In fact on an average for the six-year period, one-year ahead purchases were actually lower cost than real-time purchases.

[12] Willis Excel Calculation Workbook Prepared for Market Analysis Report, Aug 24 2007.

Figure 2 - Mid-C Daily Index vs. Forward Prices (January 2001 to December 2006)



Source: Willis Excel Calculation Workbook Prepared for Market Analysis Report, Aug 24 2007.

Period after High Spot Market

If power is purchased on a forward basis at a time when real-time or spot market prices are high, the premium paid for forward contracts is very high. This is illustrated by reviewing the period from January 2002 until December 2002. The real-time prices for all of 2001 were relatively high and forward contracts made during that period, generally resulted in the purchaser paying a high premium. The figure and table below indicates the premium that was paid in that period for forward contracts[13].

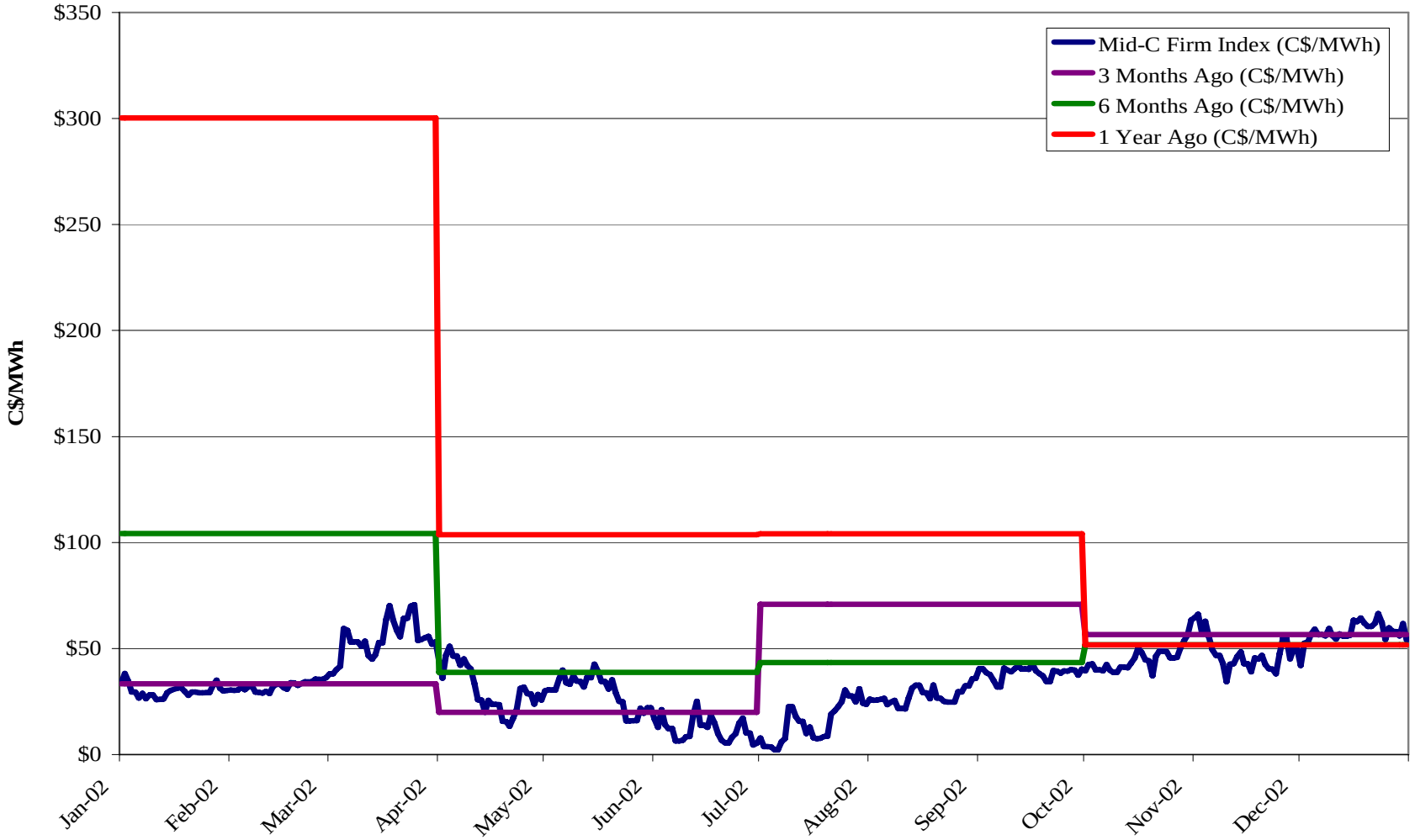
Table 4 - Mid-C Daily Index vs. Forward Prices, C$/MWh (January 2002 to December 2002)

Average Mid-C Price Over Period	Average Price if Power Purchased Three Months in Advance	Average Price if Power Purchased Six Months in Advance	Average Price if Power Purchased One Year in Advance
$35.13	$45.32	$59.36	$139.19

This analysis indicates the risks involved in forward purchasing. The six-year analysis indicated that purchasing one year ahead would be good practice. However, if forward purchases are made during a period when real-time prices are high the premium for forward purchases can be significant.

[13] Willis Excel Calculation Workbook Prepared for Market Analysis Report, Aug 24 2007.

Figure 3 - Mid-C Daily Index vs. Forward Prices (January 2002 to December 2002)



Source: Willis Excel Calculation Workbook Prepared for Market Analysis Report, Aug 24 2007.

Period after Low Spot Market

If power is purchased on a forward basis at a time when real-time or spot market prices are low, the premium paid for forward contracts is low or even negative. This is illustrated by reviewing the period from July 2005 to January 2006. The real-time prices in the immediately preceding period April to July 2005 were low. The table and figure below indicate the actual benefit that was obtained from forward contracts in that period[14].

Table 5 - Mid-C Daily Index vs. Forward Prices, C$/MWh (April 2005 to January 2006)

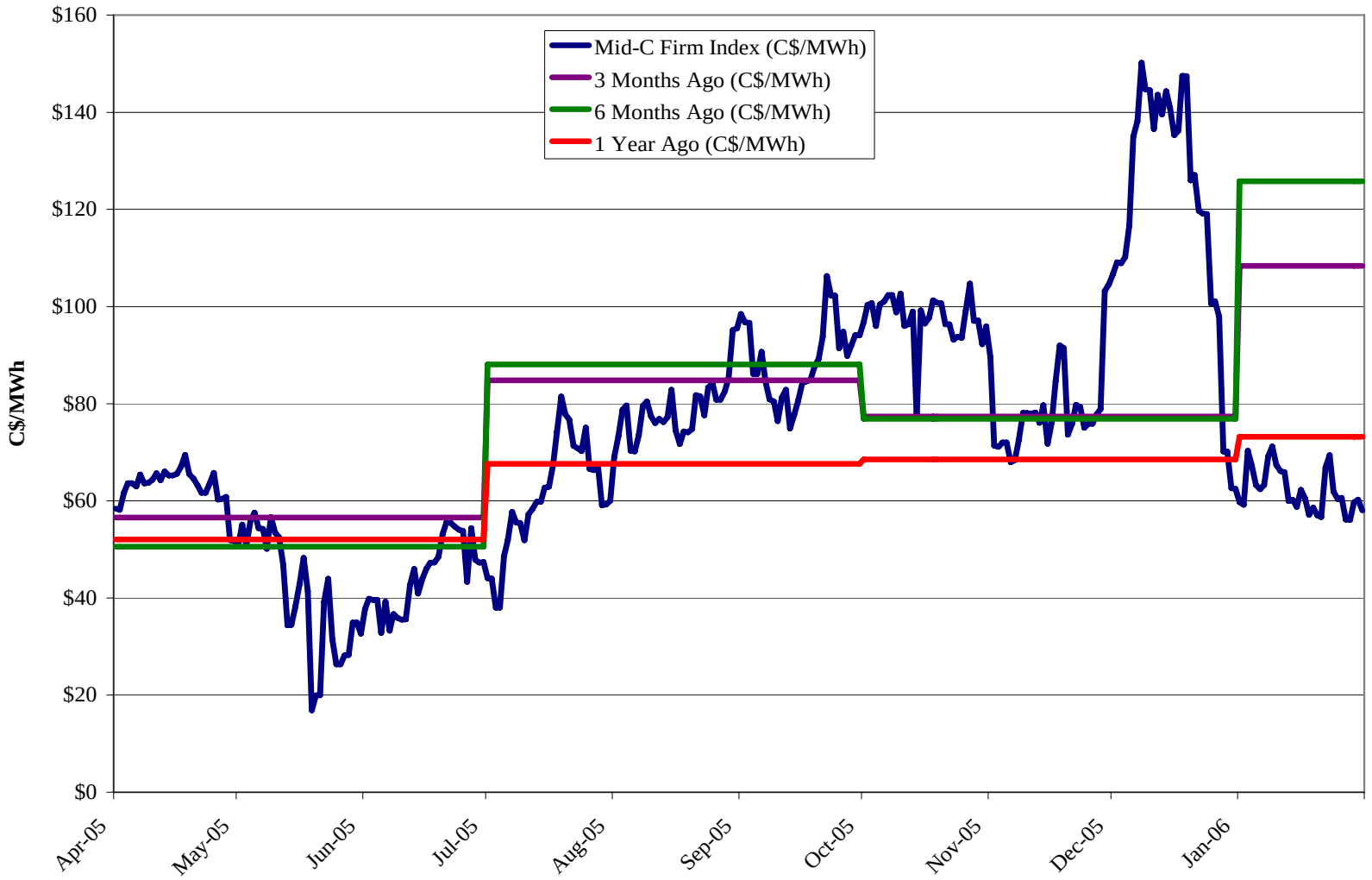
Average Mid-C Price Over Period	Average Price if Power Purchased Three Months in Advance	Average Price if Power Purchased Six Months in Advance	Average Price if Power Purchased One Year in Advance
$73.55	$76.56	$77.36	$63.85

The analysis indicates on an average if power used during this period was purchased one-year in advance the price paid would be only 87% of the price paid if the power were purchased from the real-time market.

In analyzing the real-time market versus the futures market it is useful to consider who is willing to pay for a hedge. When real-time prices are high, purchasers will more likely pay for a hedge than sellers. Buyers are very aware during these periods of their risk to price excursions and therefore interested in limiting their exposure and are willing to pay for it. When real-time prices are low, sellers will more likely pay for a hedge because they are interested in locking in production from their facilities at a profit level. During these periods Sellers are very aware of their exposure to extreme low prices.

[14] Willis Excel Calculation Workbook Prepared for Market Analysis Report, Aug 24 2007.

Figure 4 - Mid-C Daily Index vs. Forward Prices (April 2005 to January 2006)



Source: Willis Excel Calculation Workbook Prepared for Market Analysis Report, Aug 24 2007.

2.5.2. Medium-term Purchases Versus Real-Time Purchases

Medium-term is defined as one to three years. The market for medium-term is far less liquid (fewer transactions) than with the short-term (three months to one year). Because of this lack of liquidity, there is not extensive information available from NYMEX which allows good statistical analysis to be performed, comparing real-time purchasing with forward purchasing.

Power Marketers do maintain this information, particularly with respect to the transactions that they make themselves. Willis discusses market conditions with Power Marketers on an ongoing basis; the key ones for the BC Market are Powerex and Shell Trading (formerly Avista).

It is important to note that marketers themselves usually do not take any risk on forward contracts. Powerex as a matter of policy does not. A marketer as soon as they make a forward contract to sell power will immediately, usually within the same day, back-up the sale contract with a buy contract, locking in usually a relatively small margin.

Based on response and discussions with marketers, it is recognized that on a statistical basis over the last six years, it is reasonable to estimate a zero premium for purchasing forward one to five years. This estimate corresponds to the one-year data from NYMEX in table 2 which indicated that over the last six year period, if power had been purchased one-year in advance on a consistent basis, the price paid would have been less than the real-time price.

However, there are caveats. The one is provided by the results in table 3, which indicated the huge premium that was paid by power purchasers who made forward contracts in 2001 for the 2002 period. Medium-term contracts made in 2001 for 2002 and beyond would have also involved a large premium over real-time prices. The actual cost for forward contracts would have been more severe than for short-term because it would have been for longer periods.

The other caveat involves the risk of over purchasing. A five-year purchase involves a purchaser estimating how much they need to purchase over a five-year period and if they purchase more than they need they will have to sell the excess back to the market. In selling the excess back to the market they may have to sell it back at less than what they paid. The opposite could also occur and they could earn a profit. However, considering that marketers themselves do not generally take the risk of trying to beat the market, most purchasers do not want to take that risk.

2.5.3. Time of Day Impact

In analyzing the market it is also important to consider time of day impact. The above sections compared real-time daily prices versus daily prices purchased on the forward market. Another consideration is the price on a high load hour basis versus Light Load Hour basis and also on a super peak versus Heavy Load Hour basis.

Table 6 compares prices paid for average Mid-C market purchases over the full Heavy Load Hour period with purchases made during the Super Peak period.

Table 6 – On Peak vs. Super Peak (Mid-C)

	December 2002 and January 2003	December 2003 and January 2004	December 2004 and January 2005	December 2005 and January 2006	December 2006 and January 2007
Average On Peak Mid-C Index for Period (US$/MWh)[15]	$35.12	$42.87	$46.95	$74.58	$55.52
Average Price for Power Purchased between 1800h and 2100h (US$/MWh)	$36.62	$44.27	$49.00	$79.41	$57.86
Premium for Super Peak relative to Non Firm On Peak	104%	103%	104%	106%	104%

Table 7 compares prices paid for average Alberta Peak market purchases over the high load lour period with purchases made during the super peak period.

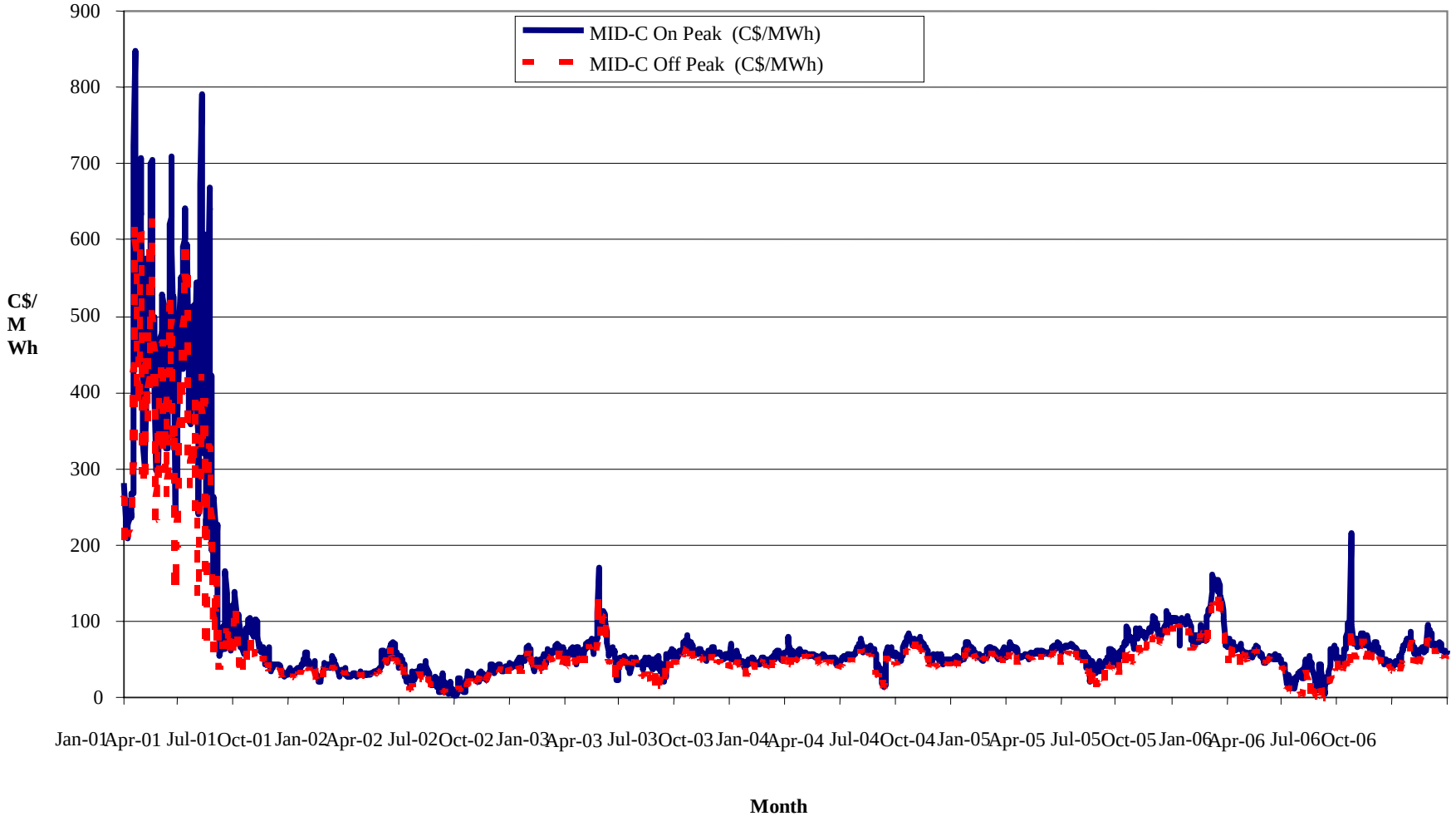
Table 7 - On Peak vs. Super Peak (Alberta Power Pool)

	December 2002 and January 2003	December 2003 and January 2004	December 2004 and January 2005	December 2005 and January 2006	December 2006 and January 2007
Average On Peak Alberta Power Pool Price for Period (C$/MWh)	$92.97	$60.56	$68.89	$109.54	$79.68
Average Price for Power Purchased between 1800h and 2100h (C$/MWh)	$167.99	$86.19	$99.63	$164.31	$102.38
Premium for Super Peak relative to Non Firm On Peak	181%	142%	145%	150%	129%

Figure 5 Plots the Mid-C prices over the six years between January 2001 and January 2007.

[15] The average on peak prices used for this calculation were the recorded non-firm purchases. Because the non-firm purchases represent more closely spot market prices.

Figure 5 –Mid C Daily Index



Source: Willis Excel Calculation Workbook Prepared for Market Analysis Report, Aug 24 2007.

3. Capacity versus Energy

Section two above involved analysis of the electricity market from the perspective of purchasing or selling electricity as an energy commodity. The electricity market can also be analyzed from the perspective of purchasing capacity.

An example of electrical capacity independent of energy is a 50 MW simple cycle dual-fuel gas turbine plant. An owner of such a plant has 50 MW available at any time for the capital cost of the equipment along with the cost of maintaining the facility in a standby condition. If the owner actually uses such a plant there will be an additional cost associated with the fuel needed to generate the power as well as the wear cost on the engine.

Besides owning a facility like a simple cycle gas turbine plant, capacity can be purchased from the market. It is usually purchased as a Call Option. That is Marketers or actual owners of generating facilities will sell the right to request delivery of a specified amount of power for a specific time period. If the Call is actually exercised there will be an additional charge for the power actually used under the Call Option.

Another version of the Call Option, is when capacity is made available upon request and if the call is actually exercised, any energy used will be returned within a certain period. In this arrangement there is no charge for the energy but there will be a charge for the call option.

A benchmark for the cost of capacity is the cost of a simple cycle gas turbine plant. Using cost data from Gas Turbine World, the cost of such a plant is $8,000 per MW per Month[16].

FortisBC's costs of purchasing capacity on the market for the last three years, during the month of January is provided below:

Table 8 - Cost of FortisBC Capacity Purchases 2004 to 2006

	Jan -2004	Jan - 2005	Jan - 2006	Average for Three Years
Market Capacity Purchase (MW)	205	85	125	138
Total Market Capacity Charge	$852,958	$386,140	$662,442	$633,847
Cost of Market Capacity ($/MW/Month)	$4,161	$4,543	$6,624	$5,109

[16] Gas Turbine World, 2006. 2006 GTW Handbook.

There is no published historical information on the market price of capacity purchases. A method for analyzing historical market costs of capacity involves assuming that blocks of energy would be purchased from the market during high load hours and a portion of that power used during high load hours and the remainder sold back to the market during low load hours. Using this method involves the following specific calculations.

1. The average cost of power during the high load hours over period under review is obtained.
2. Transmission and marketer margin costs are added to this average cost.
3. Analyzing FortisBC historical load duration curves the percentage of power that would have been used can be estimated.
4. A value for sell-back transaction costs is estimated. FortisBC System Control and Power Supply staff have found that not all the surplus energy purchased with block purchases can be sold back to the market because of the daily and real-time load forecast uncertainty. When power cannot be sold back, it then effectively displaces power that would otherwise by purchased from BC Hydro at the 3808 rate of $27.70 per MWh. In order to account for this transaction cost, a discount factor of 0.85 is applied to the low load hour sell-back price[17].

Using this approach and real-time Mid-C data, the average cost of capacity for January 2004, January 2005 and January 2006 would have been $10,376 per MW per month.

It is important to note that using this method the cost of market capacity for January 2001 would have been $38,108 per MW per Month. The year 2001 was selected because that was a high market cost year.

The table below summarizes the different costs of capacity from the discussion above.

Table 9 - Comparison Cost of Purchasing Capacity in $/MW/Month

Cost of Capacity per Month Gas Turbine Plant	FortisBC Average Cost of Purchasing Capacity for Jan 2004, Jan 2005 and Jan, 2006	Estimated Market Cost of Purchasing Capacity Jan 2004, Jan 2005 and Jan 2006	Estimated Market Cost of Purchasing Capacity January 2001
$8,000	$5,109	$10,376	$38,101

3.1. Purchasing Capacity Forward

Purchasing capacity on a forward basis can be analyzed using the forward energy analysis as a base. However, it is important to note that there is a significant risk difference due to the sell-back provision. Purchasing capacity two years ahead for example involves locking in the cost of the power purchased during the high load hours

[17] FortisBC internal report.

and it also involves locking in the value of the power sold back to the market during low load hours.

The exhibit on the following page compares purchasing capacity on a forward basis versus purchasing it on a spot market or real time basis. The exhibit below summarizes the results which are similar to the results for purchasing energy in that on a statistical basis over the six-year period from January 1, 2001 to December 2006 there is no obvious advantage in purchasing forward.

Table 10 – Cost of Purchasing Capacity in $/ per MW

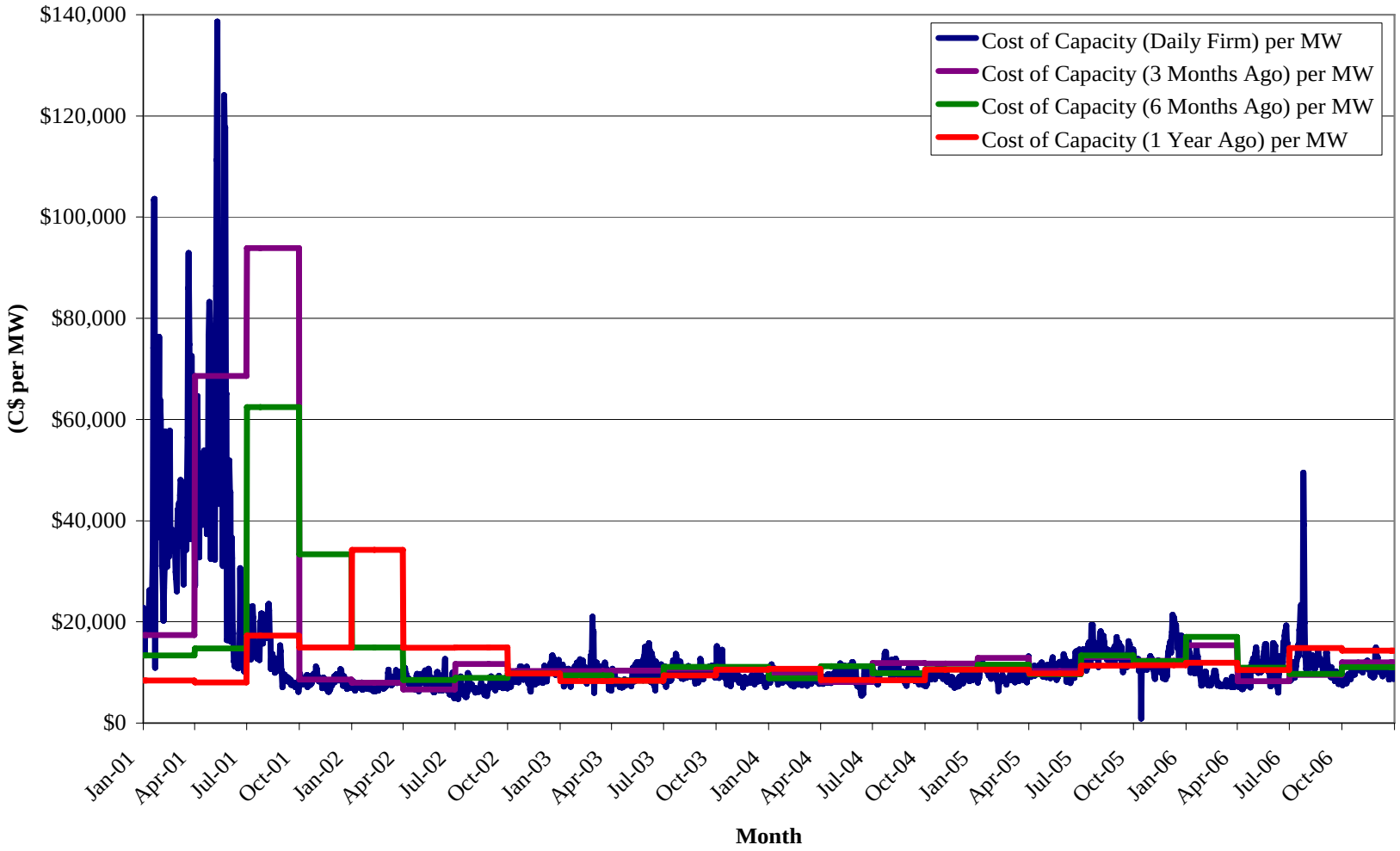
Cost of Capacity, Spot Market (Daily Firm) $ per MW	Cost of Capacity (3 Months Forward Purchase) $ per MW	Cost of Capacity (6 Months Forward Purchase) $ per MW	Cost of Capacity (1 Year Forward Purchase) $ per MW
$12,850	$16,770	$14,273	$12,157

The above values were calculated as follows:

1. Prices for High Load Hour (HLH) power for spot, and forward conditions were tabulated.
2. $15.00 was added to these values to account for transmission and marketer costs.
3. Prices for Low Load Hour (LLH) power for spot, and forward conditions were tabulated.
4. An 80% discount factor was applied to these LLH prices to account for transaction costs of selling back to the market.

Although the above analysis indicates that there is no advantage in purchasing capacity forward from the market on a long-term basis, purchasing forward does provide price certainty and also can reduce the potential of not being able to obtain power at critical periods. When capacity is purchased forward, the marketer will also need to secure the transmission capacity which increases the reliability of supply during a critical period.

Figure 6 – Cost of Capacity ($ per MW)



Source: Willis Excel Calculation Workbook Prepared for Market Analysis Report, Aug 24 2007.

4. Electricity Market Price Projections

4.1. Forecast Prices

Different organizations forecast the market price for electricity; the forecasts considered the most useful for this analysis were:

- Annual Energy Outlook, published by the Energy Information Administration, United States Department of Energy (EIA-DOE).
- Forecast developed by BC Hydro and documented in their latest Integrated Energy Plan (IEP-BCH).
- Forecast developed by Puget Sound Energy as part of their Resource Plan (RP-PSE).

The Table below indicates the annual forecast values from these three sources.

Table 11 - Electricity Price Forecasts
Mid-C Market (2008 Real C$/MWh)

Year	EIA-DOE (2008 Real C$/MWh)	IEP-BCH (2008 Real C$/MWh)	RP-PSE 2008 Real C$/MWh)
2008	$72.39	$55.18	$61.58
2009	$71.10	$56.24	$57.69
2010	$69.17	$59.85	$54.61
2011	$66.25	$63.14	$51.91
2012	$64.47	$65.79	$57.88
2013	$63.70	$68.13	$57.80
2014	$63.23	$72.16	$57.98
2015	$63.21	$72.16	$56.75
2016	$63.76	$73.22	$55.74
2017	$64.70	$75.88	$57.57
2018	$65.36	$78.00	$57.55
2019	$65.28	$79.59	$58.84
2020	$65.55	$79.38	$57.49
2021	$65.76	$81.18	$57.83
2022	$65.82	$80.65	$58.65
2023	$66.07	$83.84	$59.22
2024	$66.53	$86.49	$60.32
2025	$66.63	$88.08	$60.90
2026	$66.47		$61.44
2027	$66.43		$62.34

The above values are weighted average values between High Load Hours and Low Load Hours

Adjustments were made to account for currency and Mid-C Market versus U.S. Market location

In considering these forecasts, it is important to note that the forecast price of natural gas is an important background to all of them. For example, the Table below compares the EIA-DOE forecast price of electricity with EIA-DOE forecast price of natural gas multiplied by spark spread of 9.5.

Table 12 –Electricity Price vs. Natural Gas Price (EIA-DOE Forecast)

Year	EIA-DOE Forecast Gas Prices (2008 Real C$/GJ)	Projected Price of Electricity (2008 Real C$/MWh) by Multiplying Gas Price by Spark Spread of 9.5	EIA-DOE Electricity Price Forecast (2008 C$/MWh)
2008	$7.59	$72.11	$72.39
2009	$7.02	$66.69	$71.10
2010	$6.69	$63.57	$69.17
2011	$6.27	$59.56	$66.25
2012	$6.11	$58.04	$64.47
2013	$5.92	$56.20	$63.70
2014	$5.92	$56.28	$63.23
2015	$5.88	$55.89	$63.21
2016	$5.98	$56.79	$63.76
2017	$6.16	$58.56	$64.70
2018	$6.12	$58.12	$65.36
2019	$6.08	$57.73	$65.28
2020	$6.14	$58.36	$65.55
2021	$6.13	$58.22	$65.76
2022	$6.25	$59.39	$65.82
2023	$6.38	$60.58	$66.07
2024	$6.50	$61.74	$66.53
2025	$6.47	$61.43	$66.63
2026	$6.51	$61.86	$66.47
2027	$6.59	$62.64	$66.43

A simple correlation analysis between the gas price forecast and the electricity forecast indicates a correlation factor of over 95%. Long-term electricity price forecasts are dominated by gas price forecasts.

In the above table the spark spread is 9.5 compared to the value calculated in section 2.4.2 of 7.3. However, it is important to note that the 7.3 value was based on fuel price and variable non-fuel operating and maintenance costs only, while the 9.5 value is based on the same components plus plant capital costs and fixed operating and maintenance costs.

Since natural gas is such an important component of future electricity prices, it is useful to consider the cost of greenhouse gas emissions. The BC government energy plan requires gas fired projects to purchase offsets so that gas fired power will have a zero net GHG impact. A combined cycle gas fired plant releases 0.36 tonnes/MWh of GHG emissions. Therefore according to BC government policy, such a plant would need to purchase 0.36 tonnes of offsets for every GWh.

Also, in general in considering that the forecast price for electricity is dependent on gas fired power, the public attitude towards gas fired power versus renewable power should be taken into account. For example, there was very strong public resistance to a proposed gas fired plant at Sumas, Washington State, both in British Columbia and in Washington State. There was also strong resistance to a proposed plant near Nanaimo. The public reactions to both projects eventually lead to both projects being cancelled. One method for accounting for the impact that this public attitude will have on future electricity price is to assume different costs for GHG emissions. The table below indicates the results of this type of analysis.

Table 13 - Impact of GHG Costs on Electricity Price Forecast

Year	EIA-DOE Forecast (2008 Real C$/MWh)	EIA-DOE Forecast plus $10/tonne GHG (2008 Real C$/MWh)	EIA-DOE Forecast plus $30/tonne GHG (2008 Real C$/MWh)	EIA-DOE Forecast plus $60/tonne GHG (2008 Real C$/MWh)
2008	$72.39	$75.99	$83.19	$93.99
2009	$71.10	$74.70	$81.90	$92.70
2010	$69.17	$72.77	$79.97	$90.77
2011	$66.25	$69.85	$77.05	$87.85
2012	$64.47	$68.07	$75.27	$86.07
2013	$63.70	$67.30	$74.50	$85.30
2014	$63.23	$66.83	$74.03	$84.83
2015	$63.21	$66.81	$74.01	$84.81
2016	$63.76	$67.36	$74.56	$85.36
2017	$64.70	$68.30	$75.50	$86.30
2018	$65.36	$68.96	$76.16	$86.96
2019	$65.28	$68.88	$76.08	$86.88
2020	$65.55	$69.15	$76.35	$87.15
2021	$65.76	$69.36	$76.56	$87.36
2022	$65.82	$69.42	$76.62	$87.42
2023	$66.07	$69.67	$76.87	$87.67
2024	$66.53	$70.13	$77.33	$88.13
2025	$66.63	$70.23	$77.43	$88.23
2026	$66.47	$70.07	$77.27	$88.07
2027	$66.43	$70.03	$77.23	$88.03

$10/tonne of GHG =	$3.60/MWh
$30/tonne of GHG =	$10.80/MWh
$60/tonne of GHG =	$21.60/MWh

4.2. Forecast Prices Relative to New Plant Costs

The marginal cost of electricity will eventually be based on the cost of new supply. B.C. Hydro's 2006 CFT is the best available information on the cost of new plants. The contracts awarded as part of that process were from 20 to 40 years.

The prices paid for these contracts appears relatively high to the current market price for electricity and interveners at recent BC Hydro rate design applications have made this observation[18]. However, current electricity price forecasts need to be considered with respect to the following two factors:

- Transmission constraints – actual price paid for electricity at any point in the region is affected by transmission costs.
- The public's preference for GHG neutral or "green" power.

The table below adds to the electricity price forecasts, a transmission adder and various levels of GHG adders and compares the results with the average price that BC Hydro will be paying under their recent CFT. This comparison indicates that the prices that BC Hydro paid are not out of line with the forecasts.

[18] BC Hydro 2007 Rate Design Application – Joint Industry Electricity Steering Committee (JIESC) Argument (August 17, 2007)

Table 14 - Forecast Prices Relative to New Plant Costs

Year	EIA-DOE Forecast (2008 Real C$/MWh)	EIA-DOE Forecast Plus $20/MWh Transmission Cost (2008 Real C$/MWh)	EIA-DOE Forecast Plus Transmission Plus $30/tonne GHG Cost (2008 Real C$/MWh)	EIA-DOE Forecast Plus Transmission Plus $60/tonne GHG Cost (2008 Real C$/MWh)	BCH 2006 CFT Costs (2008 Real C$/MWh)
2008	$72.39	$92.39	$103.19	$124.79	$101.70[19]
2009	$71.10	$91.10	$101.90	$123.50	$101.70
2010	$69.17	$89.17	$99.97	$121.57	$101.70
2011	$66.25	$86.25	$97.05	$118.65	$101.70
2012	$64.47	$84.47	$95.27	$116.87	$101.70
2013	$63.70	$83.70	$94.50	$116.10	$101.70
2014	$63.23	$83.23	$94.03	$115.63	$101.70
2015	$63.21	$83.21	$94.01	$115.61	$101.70
2016	$63.76	$83.76	$94.56	$116.16	$101.70
2017	$64.70	$84.70	$95.50	$117.10	$101.70
2018	$65.36	$85.36	$96.16	$117.76	$101.70
2019	$65.28	$85.28	$96.08	$117.68	$101.70
2020	$65.55	$85.55	$96.35	$117.95	$101.70
2021	$65.76	$85.76	$96.56	$118.16	$101.70
2022	$65.82	$85.82	$96.62	$118.22	$101.70
2023	$66.07	$86.07	$96.87	$118.47	$101.70
2024	$66.53	$86.53	$97.33	$118.93	$101.70
2025	$66.63	$86.63	$97.43	$119.03	$101.70
2026	$66.47	$86.47	$97.27	$118.87	$101.70
2027	$66.43	$86.43	$97.23	$118.83	$101.70

$10/tonne of GHG = $3.60/MWh
$30/tonne of GHG = $10.80/MWh
$60/tonne of GHG = $21.60/MWh

5. Conclusions

Purchasing capacity and energy forward contracts is affected by the current spot market price when the forward contracts are transacted. If forward contracts are made when spot market prices are high (more than $100 per MWh), the price paid will probably be higher

[19] The value of $101.70 per MWh is a conversion of $87.50 per MWh value indicated in Section 2.4.6 to an unlevelized $2008 value assuming a 30-year plant life.

than if purchases are made on a spot market basis. On the other hand if forward contracts are made when current spot market prices are low, the price paid will probably be roughly the same or lower than if made on a spot market basis.

Generally, longer term forward purchases (more than three months) are more likely to be lower than spot market prices than short-term (less than three months) forwards.

When purchasing forward, it is prudent to purchase considerably more than three months in advance and attempt to purchase under an established price cap. This price cap will vary over time but a suitable price cap at the present time for the November to February period is $70 per MWh.

Electricity market price forecasts are dominated by natural gas price forecasts and these forecasts are based on a market hub like Mid-C. Accordingly market forecasts based on historical Mid-C prices and the short-term Mid-C forward market need to be considered in light of transmission constraints and the public's preference for GHG neutral power.

A gap in power supply for the whole region is developing because it is difficult to permit new gas-fired and coal-fired plants. The 2006 long-term plan published by the Western Electricity Coordinating Council indicated that 60% of required new generation would come from gas-fired plants and 25% from coal-fired plants. However, the public in a number of cases has rejected these types of plants and a number of projects have been cancelled.

Transmission constraints in the region are going to become more serious as margins in the region diminish. Purchasing capacity from other utilities on a long-term basis is going to become increasingly more difficult.

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Load Forecast & Monte Carlo Key Inputs

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FortisBC staff made some adjustments in late 2008 and early 2009 to reflect recent Load Forecast updates.

1 Load Forecast & Monte Carlo Key Inputs

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1.1 Monte Carlo Key Inputs

1.1.1 Population Growth

The key driver for the FortisBC forecast was the population forecast, which was obtained from the Statistics Service Section of the B.C. Ministry of Labour. The table below indicates the forecast that was provided by this group for the FortisBC service territory.

Table 1: BC Stats Population Forecast for FortisBC Service Territory

Year	Population Forecast
2009	276,216
2010	279,038
2011	281,804
2012	284,626
2013	287,383
2014	290,140
2015	292,894
2016	295,608
2017	298,326
2018	300,981
2019	303,589
2020	306,176
2021	308,728
2022	311,189
2023	313,578
2024	315,899
2025	318,156
2026	320,343
2027	322,449
2028	324,486

The population forecast is based upon historical and projected population growth and average household inhabitants based on the service territory portion of regional areas in the province. In analyzing this

forecast it is useful to consider the accuracy of previous forecasts.
The exhibit below indicates the results of reviewing a number of historical provincial forecasts and their accuracy with respect to actual data.

Table 2: Historical Population Forecast Accuracy Levels

Forecast Years Ahead	Average Error	Range of Error	
1	0.4%	-0.6%	0.6%
2	0.6%	-0.8%	1.0%
3	0.9%	-0.9%	2.0%
4	1.4%	0.4%	2.7%
5	3.5%	0.5%	3.5%
6	4.3%	4.2%	4.3%
7	5.0%	4.8%	5.2%
8	5.6%	5.2%	5.9%
9	6.0%	5.6%	6.5%
10	6.9%	6.9%	6.9%
11	7.4%	7.4%	7.4%

As would be expected, the Range of Error increases the further out forecasts are projected.

Another approach for examining population growth variability is to consider the historical variation in population growth. The table below indicates the historical variation in population growth for the FortisBC service territory.

Table 3: Historical Population Growth for FortisBC Territory

Year	Population	Annual % Growth
1978	188,529	0.8%
1979	191,329	1.5%
1980	197,355	3.1%
1981	200,292	1.5%
1982	197,438	-1.4%
1983	194,584	-1.4%
1984	191,730	-1.5%
1985	188,876	-1.5%
1986	186,022	-1.5%
1987	186,946	0.5%
1988	189,332	1.3%
1989	193,936	2.4%
1990	201,218	3.8%
1991	208,160	3.4%
1992	217,339	4.4%
1993	225,950	4.0%
1994	233,570	3.4%
1995	238,720	2.2%
1996	243,214	1.9%
1997	246,568	1.4%
1998	248,602	0.8%

Year	Population	Annual % Growth
1999	249,482	0.4%
2000	250,277	0.3%
2001	251,221	0.4%
2002	252,677	0.6%
2003	254,590	0.8%
2004	254,963	0.1%
2005	258,751	1.5%
2006	263,467	1.8%
2007	270,824	2.8%

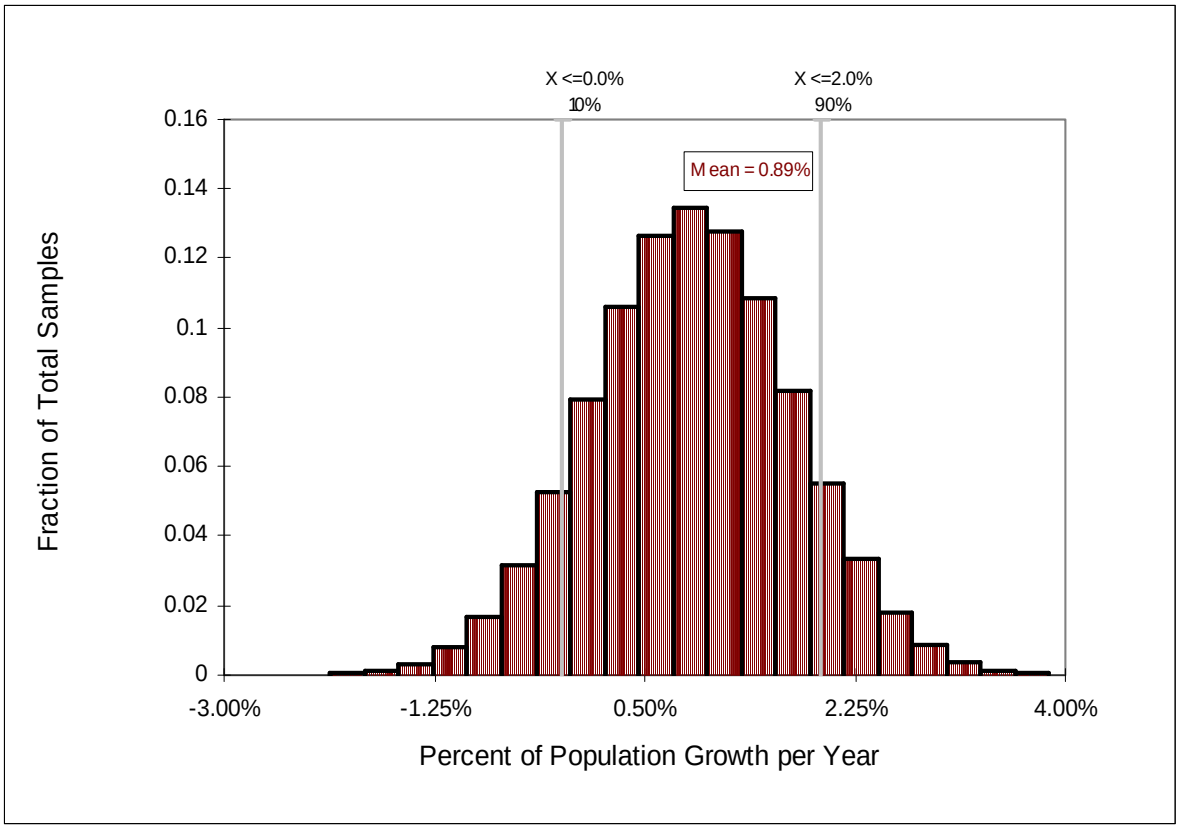
Considering the above information, the following Monte Carlo approach was used. The Expected Forecast population was split into the following periods:

- Years 2009 and 2010;
- Years 2011 to 2015;
- Years 2016 to 2020;
- Years 2021 to 2025; and
- Years 2026 to 2028.

The logic for breaking the forecast into periods is that for the early years 2009 and 2010, it is expected that the forecast range of error would be relatively small based on historical forecast results and that the variability of the forecast error over the longer term is adequately expressed in five-year periods.

For years 2009 and 2010, there was no variation assumed relative to the expected forecast. For each of the subsequent five-year periods, the average forecast percent growth was calculated. For example, the forecast percent growth for years 2011 to 2015 is 1.0 percent for 2016 to 2020 it is 0.9%, for 2021 to 2025 it is 0.7% and for 2026 to 2028 it is 0.6%. A normal probability distribution was then assumed for each of these periods. The graph below indicates the distribution assumed for the period 2016 to 2020.

Graph 1: Probability Distribution for Population Growth Years 2016–2020

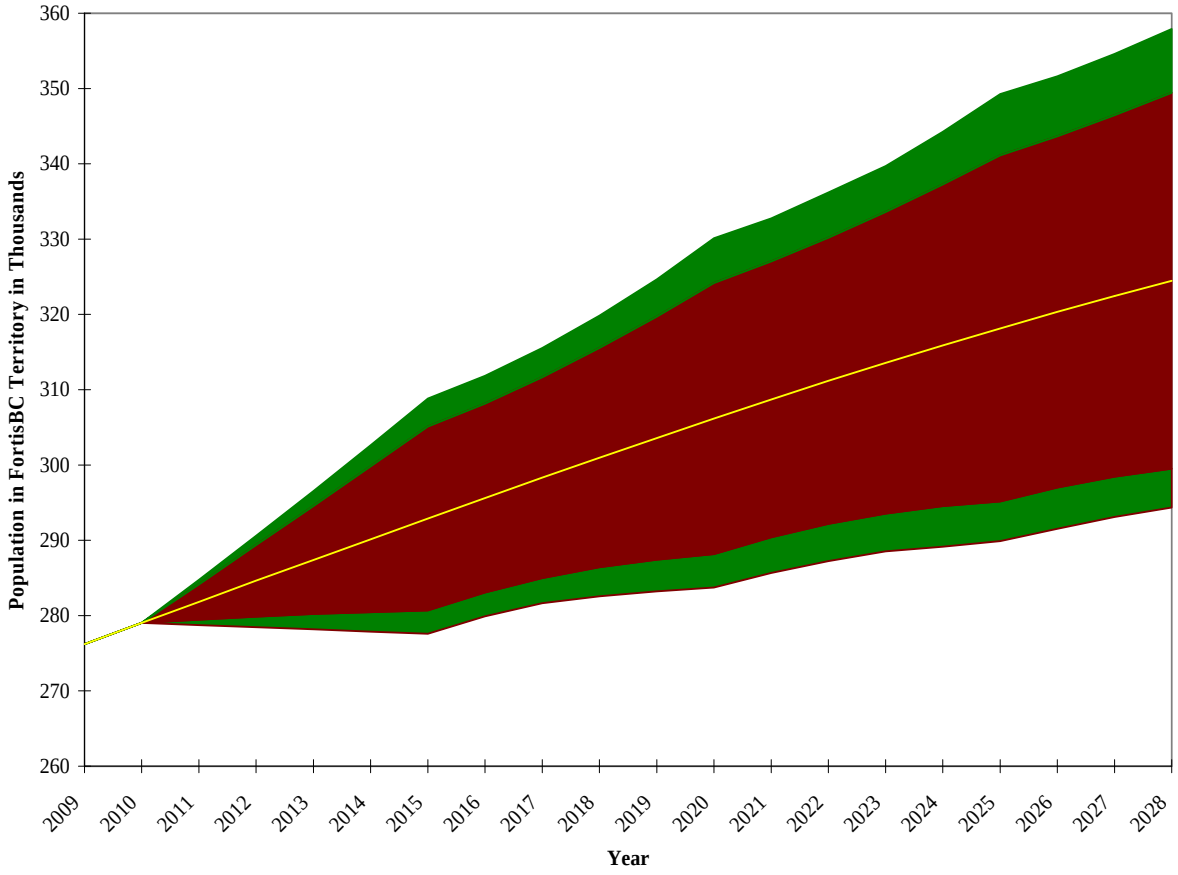


The above exhibit indicates that for the years 2016 to 2020, the Monte Carlo simulation assumed that there was an 80% probability of the population growth being between 0.0% and 2.00% with the most likely value being the forecast value of 0.89%.

The above probability distribution was based on a normal distribution with a standard deviation of 0.84 percentage points. The normal distribution assumes that the population forecast has an equal probability of being too high or too low. The standard deviation value was based on the fact that the standard deviation of the actual percent population growth over the last 10 years being 0.84 percentage points.

The graph below indicates the Monte Carlo simulation output for the population forecast.

Graph 2: FortisBC Region Population (2009 to 2028)

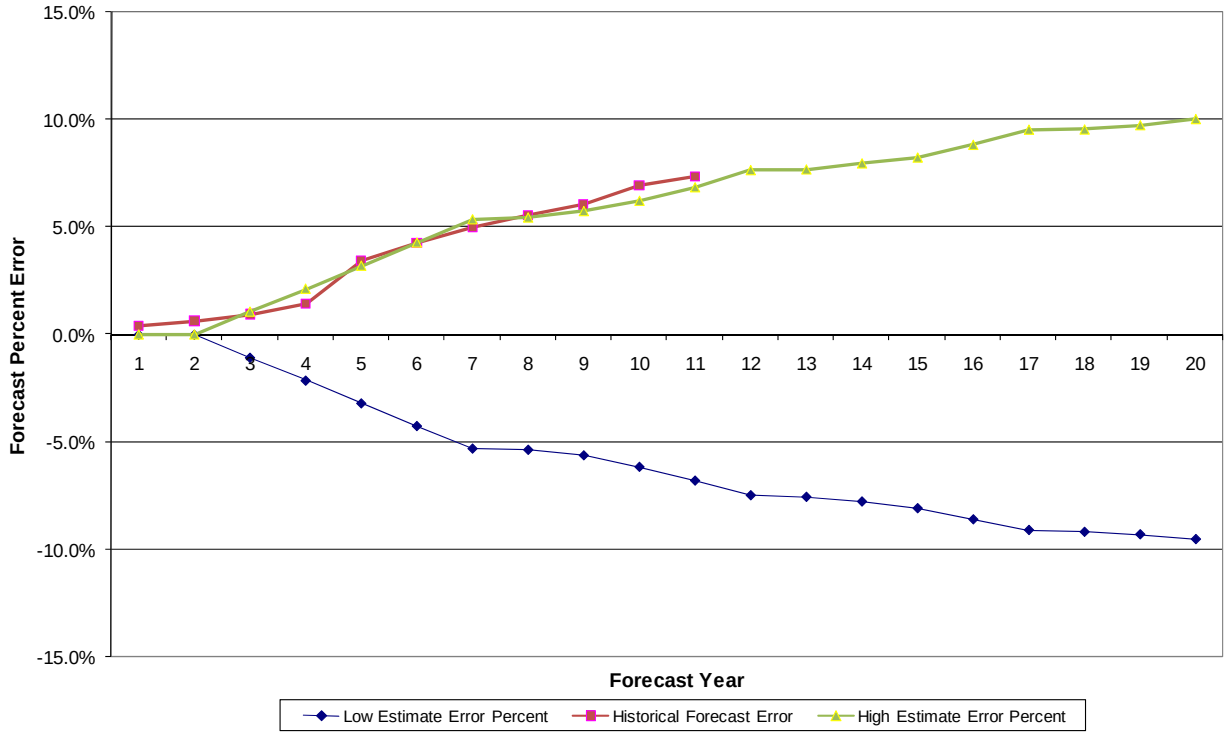


The burgundy-shaded area indicates the range of outputs that are within one Standard Deviation of the mean value. The combined burgundy and green shaded areas indicate the range that 80% of the output values are within. Ten percent of the output values are above this range and ten percent are below.

It is interesting to plot the range of error for the historical forecasts with this Monte Carlo range, as indicated in Graph 3. The x-axis indicates the number of years into the future being forecast while the y-axis indicates the difference between the forecast values and actual. For example, the pink plot indicates that an historical forecast made eleven years previously was 7.4% different than the actual population.

The result of this analysis is some verification that based upon historical data, the projected range provides a satisfactory forecast of this all-important variable.

Graph 3: FortisBC Service Territory Population Forecast Error



1.1.2 Load Forecast Drivers & System Components

The following table provides an overview of the key variables that drive the forecast along with comments as to the data sources for these variables.

Table 4: FortisBC Load Forecast Drivers

Forecast Drivers	Comments
Population Growth	Population forecast is provided by British Columbia Statistical services and is a forecast tailored to suit the FortisBC service area.
Factor relating Residential Customer Count to Population Growth	Linear Regression equation based on a 10-year and a 20-year (20-year for 2013 and beyond) trend relating the population in FortisBC's jurisdiction to the number of FortisBC Residential customers
Factor relating General Service (GS) Customer Count to Population Growth	Linear Regression equation based on 20-year trend relating the population in FortisBC's jurisdiction to the number of FortisBC General Service Customers
Factor relating Wholesale Load (in MWh) growth to Population Growth	Linear Regression equation based on 20-year trend relating the population in FortisBC's jurisdiction to Load in MWh from wholesale customers.

Forecast Drivers	Comments
Industrial Load Growth	Surveys from large industrial customers combined with growth trends and analysis.
Residential Use Per Customer (UPC)	Linear Regression equation based on historical trend relating load and customer count growth to residential use per customer and normalized for weather variations
General Service Use Per Customer (UPC)	Linear Regression equation based on historical trend relating load and customer count growth to General Service Use per customer

The above-identified forecast drivers are used as input variables in the FortisBC forecast model. Besides these direct drivers there are a number of exogenous factors that affect load growth. The forecast model does not include these factors as specific variables; however, the forecast procedure does consider their impact qualitatively as indicated in the table below.

Table 5: Exogenous Factors and Forecast Consideration

Exogenous Factors	Forecast Consideration
Economic GDP Forecast	Changes in the rate of economic growth are assumed to be reflected in the factors relating residential and general service customer growth to population and in use per customer.
Natural Gas Price	Natural gas prices are volatile. The Expected Forecast assumes that gas prices will stabilize at their present levels and that at those levels there will not be a significant switch from gas heating to electric heating. However, in determining the range of probable UPCs, consideration was given to a potential switch due to higher than forecast gas prices.
Electricity Prices	It is assumed that the prices that customers pay for electricity will not significantly affect their present level of consumption.
Environmental Requirements	Environmental considerations are going to have a major impact on the supply side or the generation sources that are available. While, in general, they are not forecast to have a significant impact on the demand side, there may be exceptions. One potential impact on the demand side, for example, would be a requirement for electrical vehicles in urban areas due to emission reduction targets.
New Electricity Uses	There are a number of potential new electricity uses, such as electric vehicles, continued growth in home entertainment products, expansion in recreational centres. Consideration is given for this potential in estimating the range of probable Residential and General Service UPCs.

Exogenous Factors	Forecast Consideration
Lifestyle Changes	Changes in lifestyle such as a significant portion of the growth in population moving from single-family residences to condominiums in the Okanagan, or a larger portion of residences being recreational property versus full time residences can affect load growth. FortisBC believes that although there have been major developments in terms of condominium living and recreational property, these trends have largely been offset by a significant growth in the number of large single family houses with the net effect being that the resulting average UPC across the residential sector has not been significantly affected.

1.1.2.1 Residential

The residential customer growth forecast begins with a review of past customer additions. The number of residential customers served directly by FortisBC has continued to increase steadily, rising from 78,008 in 2000 to 95,502 in 2008. Annual energy requirements for the residential sector have increased from 987 GWh in 2000 to 1,225 GWh in 2008.

Projections of future growth are developed using population projections made by BC Statistics. An average, weather-normalized use-per-customer value is calculated, and multiplied by the projected number of accounts to obtain annual energy sales over the forecast period. An average annual growth rate of about 1.2 percent from 2009 to 2028 will see the number of FortisBC residential customers increase to 120,118 by 2028. The residential energy requirements are forecast to be 1,515 GWh by 2028 with the major driver being population growth.

1.1.2.2 General Service

This class of customers is broad, encompassing a range of sub-classes, including finance, insurance, and real estate services; wholesale and retail trade; community business and personal services; public administration; transportation, communication, and other miscellaneous commercial sector customers.

The growth and demand of this customer class is strongly correlated with growth in the number of residential customers in the FortisBC service area. As a result, general service will grow as the regional population expands. General Service category annual energy sales have increased from 498 GWh in 2000 to 668 GWh in 2008. By 2028 General Service annual energy forecast is expected to be 976 GWh.

1.1.2.3 Industrial

Forestry, pulp and sundry comprise over one-third of FortisBC industrial customers. Other classes of customers include large educational institution, growers, construction, manufacturing and mining. Where possible, electricity use and forecast energy demand information are obtained from individual industrial customers. Industrial loads have varied significantly in the last several years due to the downturn in the forestry industry. By 2028 the industrial annual energy forecast is 296 GWh.

1.1.2.4 Wholesale

FortisBC sells wholesale power to municipalities within its service area that own and operate their own electrical distribution system, and to BC Hydro at Lardeau and Kingsgate. The municipal utilities are the cities of Grand Forks, Kelowna, Nelson, Penticton and the District of Summerland.

The expected forecast projects that the while the number of wholesale customers remains constant for the forecast period, they will each experience continued growth. The expected annual energy forecast is 1,060 GWh for 2028.

1.1.2.5 Irrigation and Lighting

Irrigation demands are a function of acreage planted, type of crop planted and local weather. Due to the variability in these factors and the challenges in forecasting, the load forecast projects a "normal" demand of 48 GWh throughout the forecast period.

For lighting it is assumed in the forecast that gains in lighting efficiency will offset increased demands from fixture additions. Lighting loads are therefore forecast to remain constant at 13 GWh for the forecast period.

1.1.2.6 System Losses

The utility must have sufficient resources to meet the energy demands at the customers' meters and therefore must accommodate system losses. FortisBC system losses consist of:

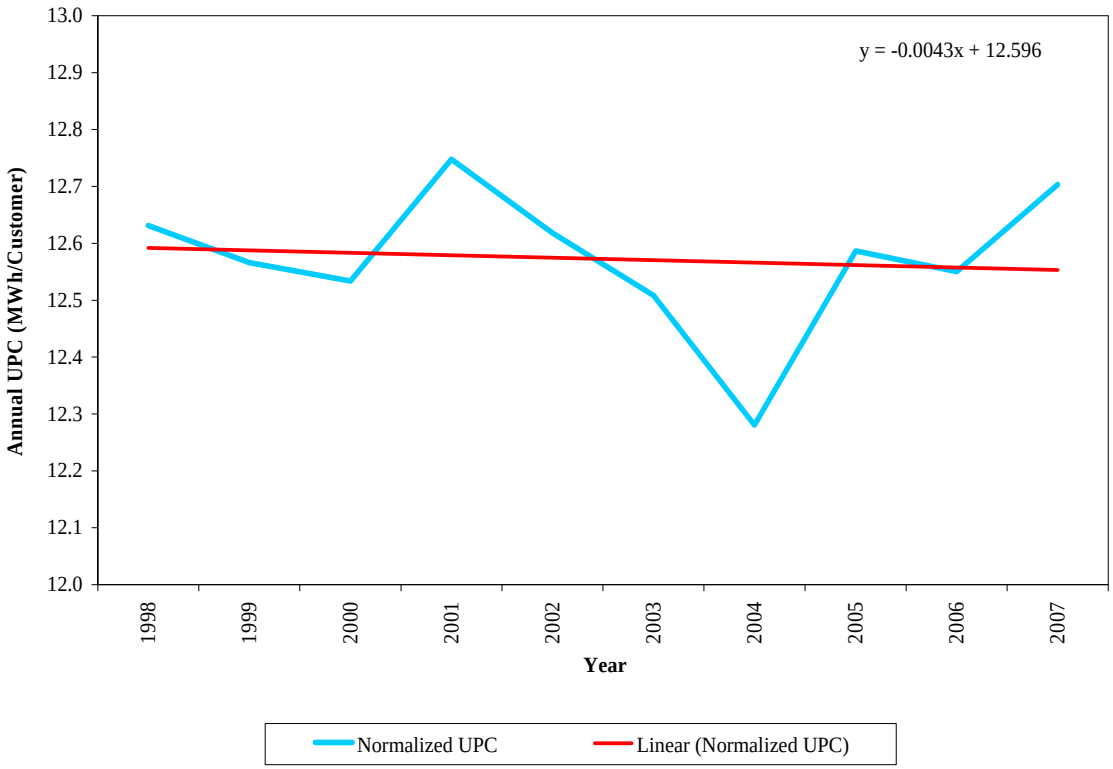
- Transmission and distribution line losses and transformation losses;
- Losses on wheeling through the BC Hydro system;
- Company use; and
- Unaccounted for energy (metering inaccuracies, theft, etc.)

Average system losses from 2000 to 2008 were 10% of the gross load. Since 2005 a number of transmission system improvements have been implemented. Gross system losses for 2008 are reported at 9.2%, comparing generation plus gross imports to the system with billed data.

1.1.3 Use Per Customer – Residential

The use per customer for the residential sectors has been trending downwards for several years as indicated in the graph below. Ongoing DSM programs, the availability of more efficient electrical appliances and declining dependence on electricity as a primary source of energy for heating and cooling are all possible explanations for the gradual decline of the UPC.

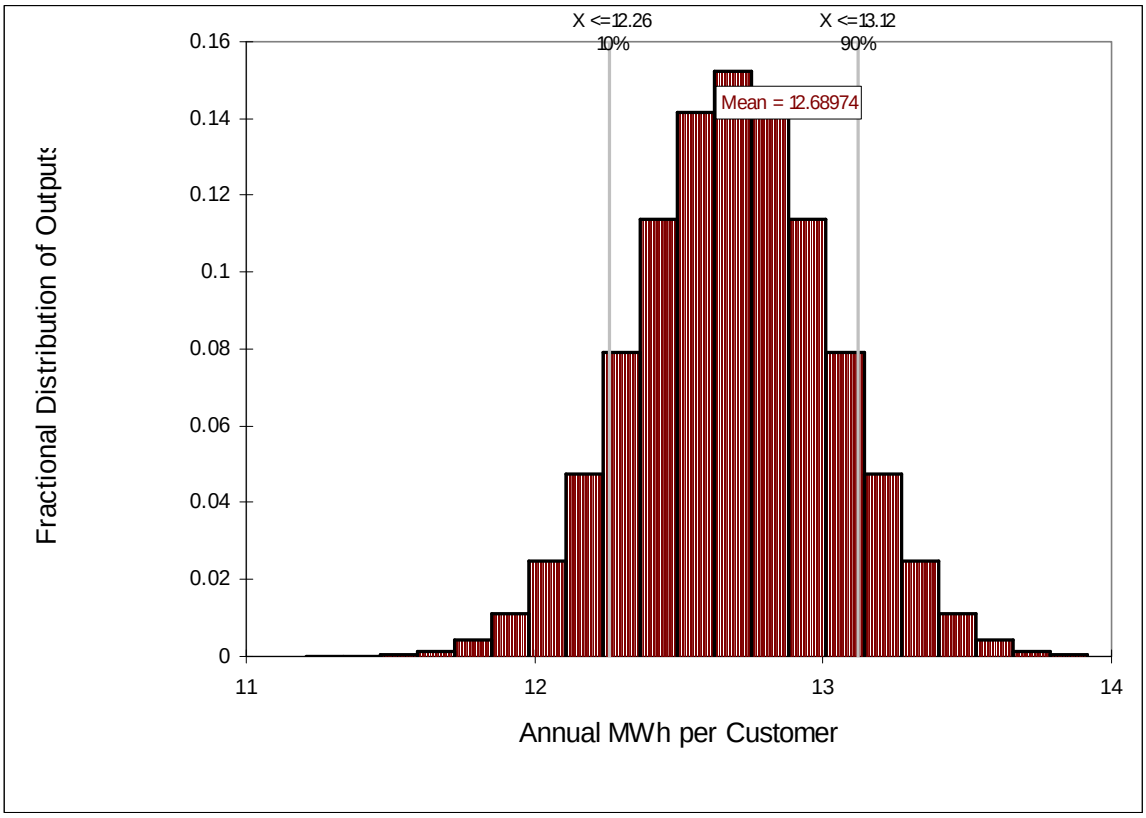
Graph 4: FortisBC Residential Use per Customer – 10-Year Trend



The linear regression of this trend indicates a small reduction in customer use. However, it should be noted that the regression statistics have an R square value of 0.0105 and from a statistical analysis perspective there is no detectable trend. In fact, use per customer has actually increased from 2005 to 2008.

The Monte Carlo analysis assumed a normal probability distribution. For illustration, a probability distribution for the year 2015 is provided below.

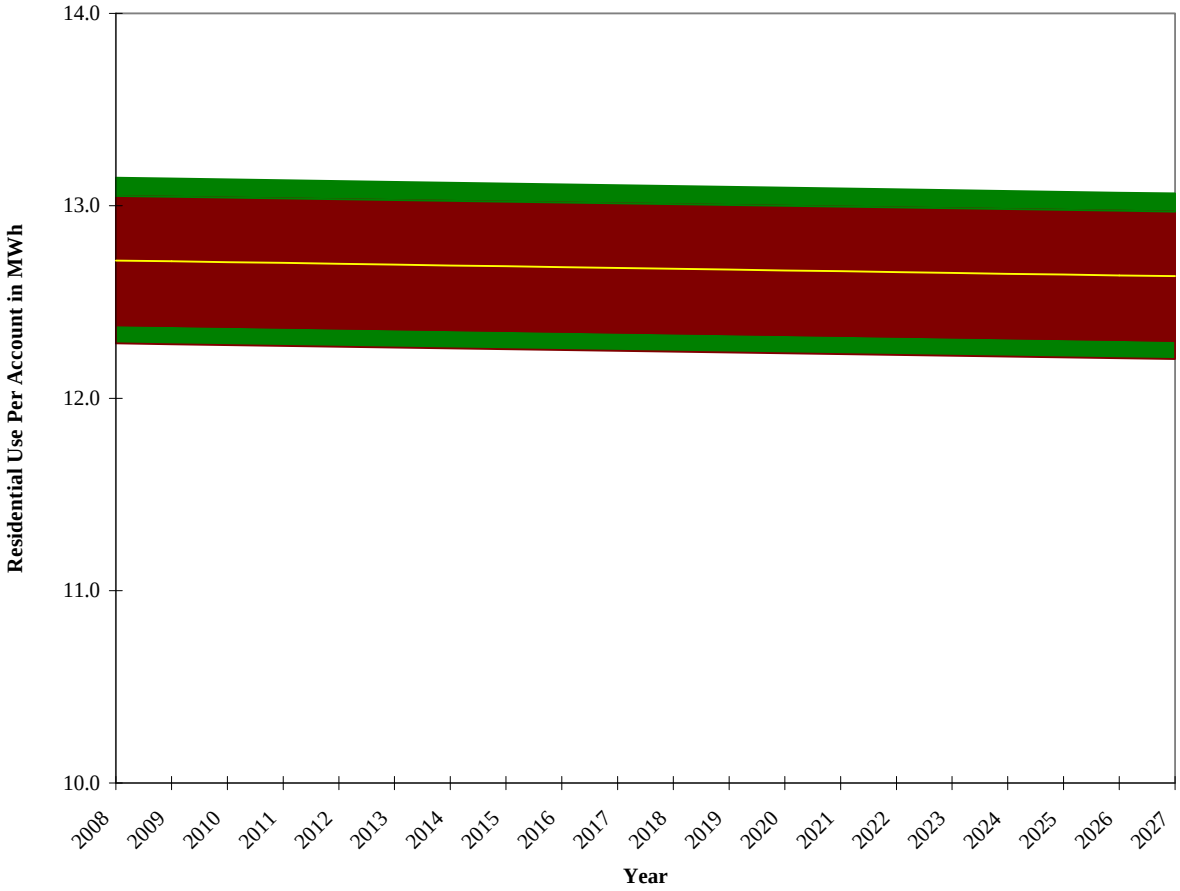
Graph 5: Use per Customer Probability Distribution – 2015



The above exhibit indicates that for the year 2015, the Monte Carlo simulation assumes a variety of UPC values ranging from a low of 11.20 MWh/customer to 13.90 MWh/customer with the average value of all the values being 12.69 MWh/customer. The average value is the one used to calculate the expected or reference Load Forecast.

The graph below indicates range of UPC values that were used in the analysis over the planning period.

Graph 6: Residential Use per Customer (MWh/Customer)



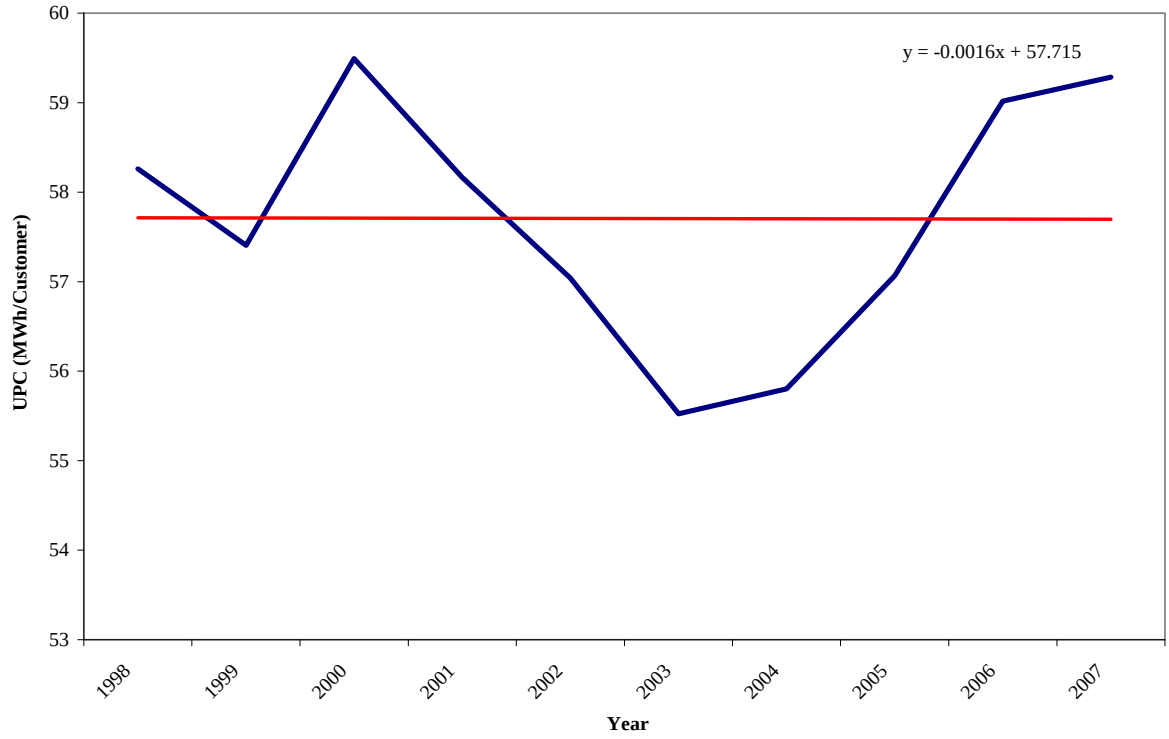
The Monte Carlo simulation involves calculating gross system load for randomly selected values over the complete range.

The result here is that the mean value is trending downwards, but there is a distribution about the mean each year.

1.1.4 Use Per Customer – General Service Sector

The 10-year trend for General Service customers has also been trending slightly downward, as indicated in the graph below. As witnesssed in the residential class, the general service average use per customer has also been trending upward in the past few years, which is likely due to larger stores and longer business hours.

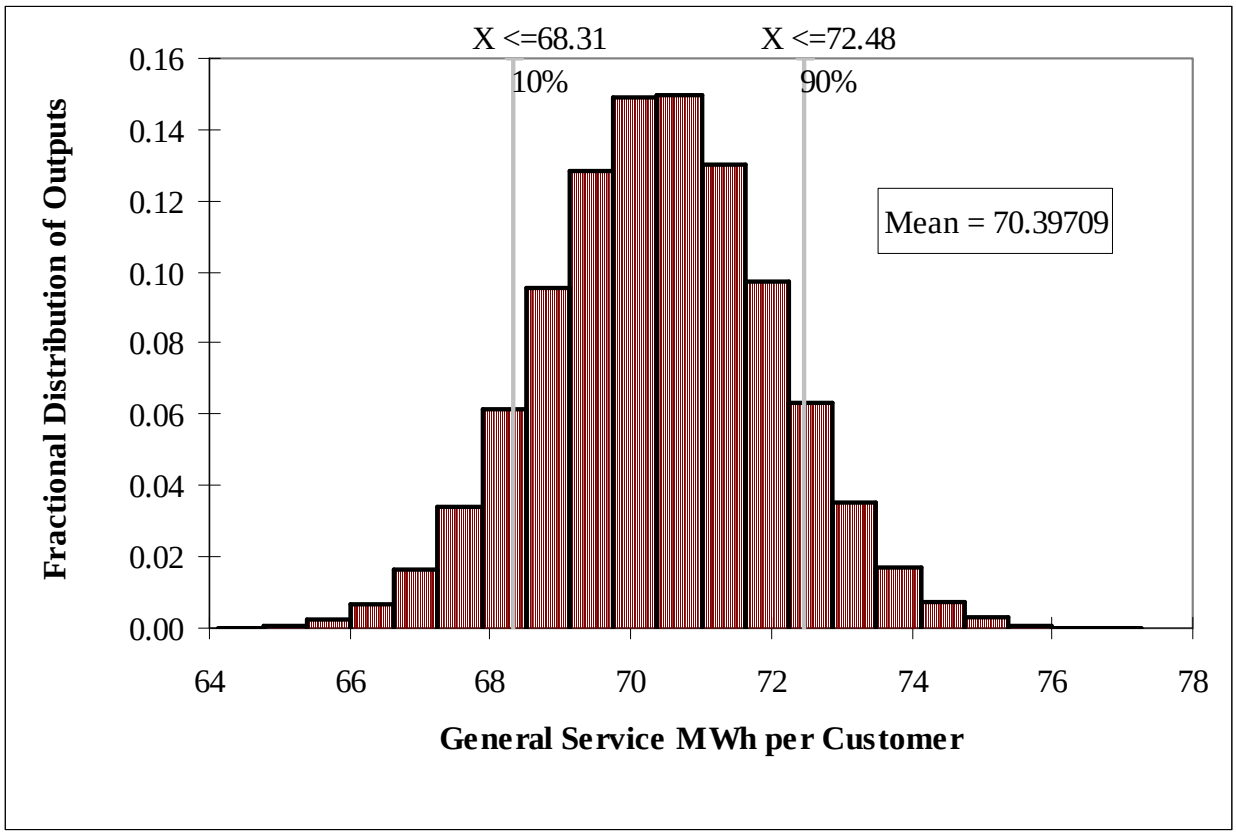
Graph 7: FortisBC General Service Use per Customer – 10-Year Historical Data



There is a significant variation in the general service use per customer (GS UPC) as indicated in the graph. From a statistical perspective, the historical data does not identify any clear trends.

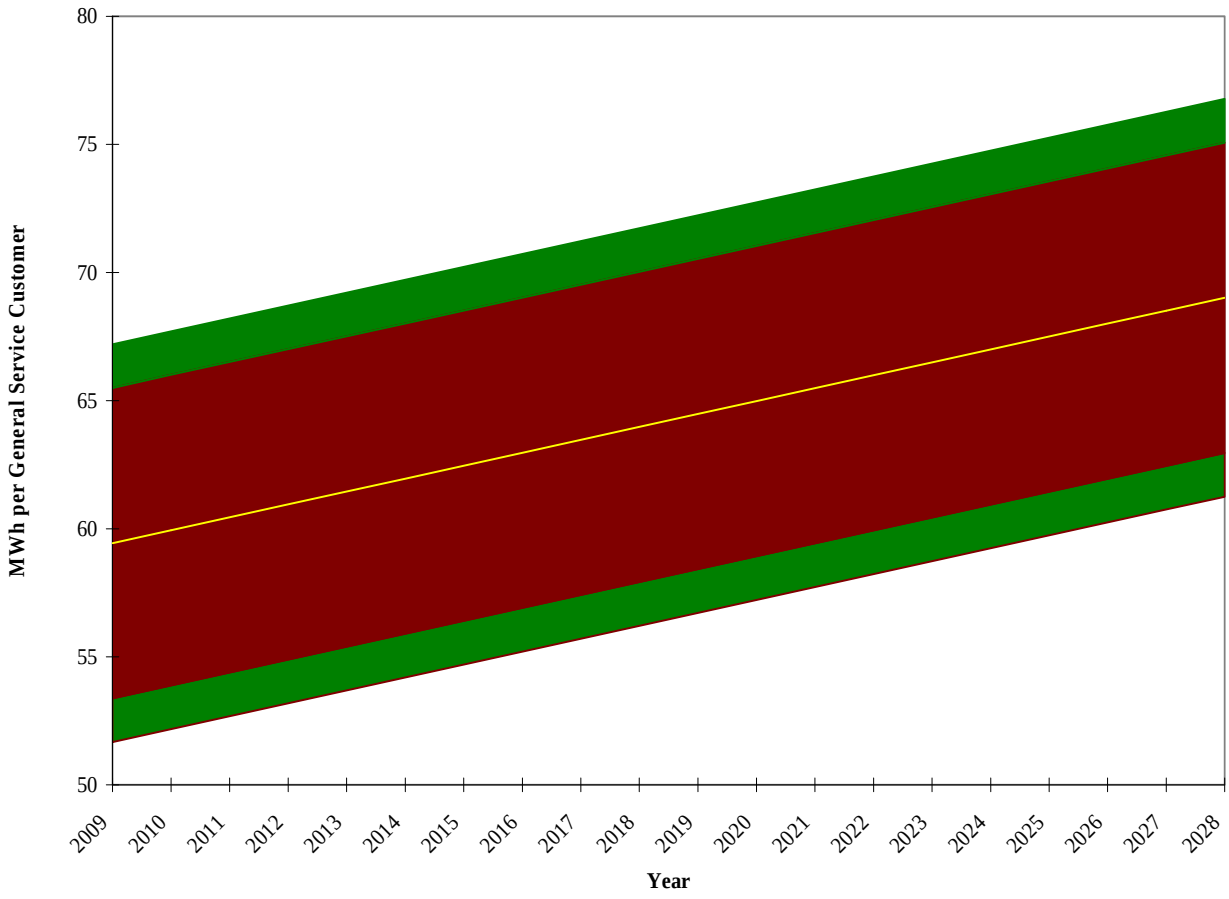
A probability distribution for the year 2027 of the GS UPC inputs used for the Monte Carlo simulation is provided below.

Graph 8: Distribution for 2027 MWh per GS Customer



The exhibit indicates that the simulation run for the year 2027 assumed that the average and most probable GS UPC value is 70.40 MWh/customer and that 80% of the values used in the simulation run were between 68.31 MWh/customer and 72.48 MWh/customer. The graph below indicates the range of GS UPC values that were used in the simulation run over the full planning period.

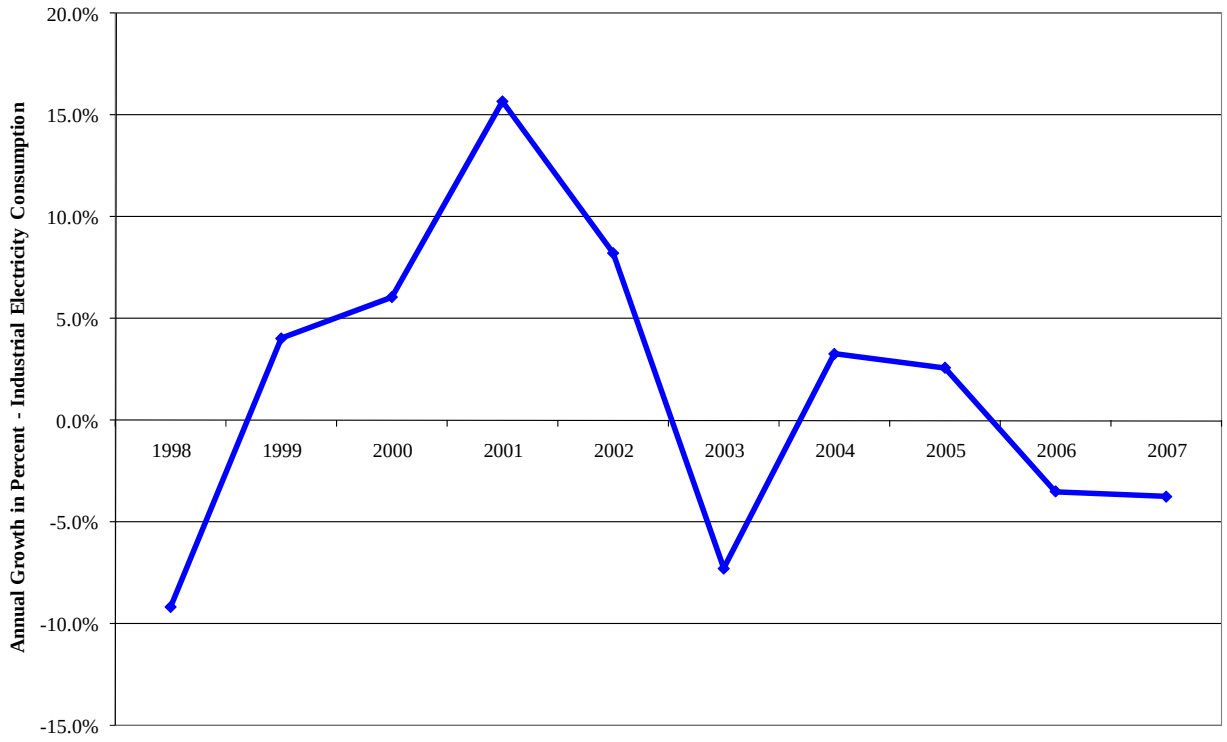
Graph 9: General Service UPC MWh/Customer



1.1.5 Industrial Load Growth

The industrial load is difficult to forecast due to industry volatilities, as indicated in the graph below.

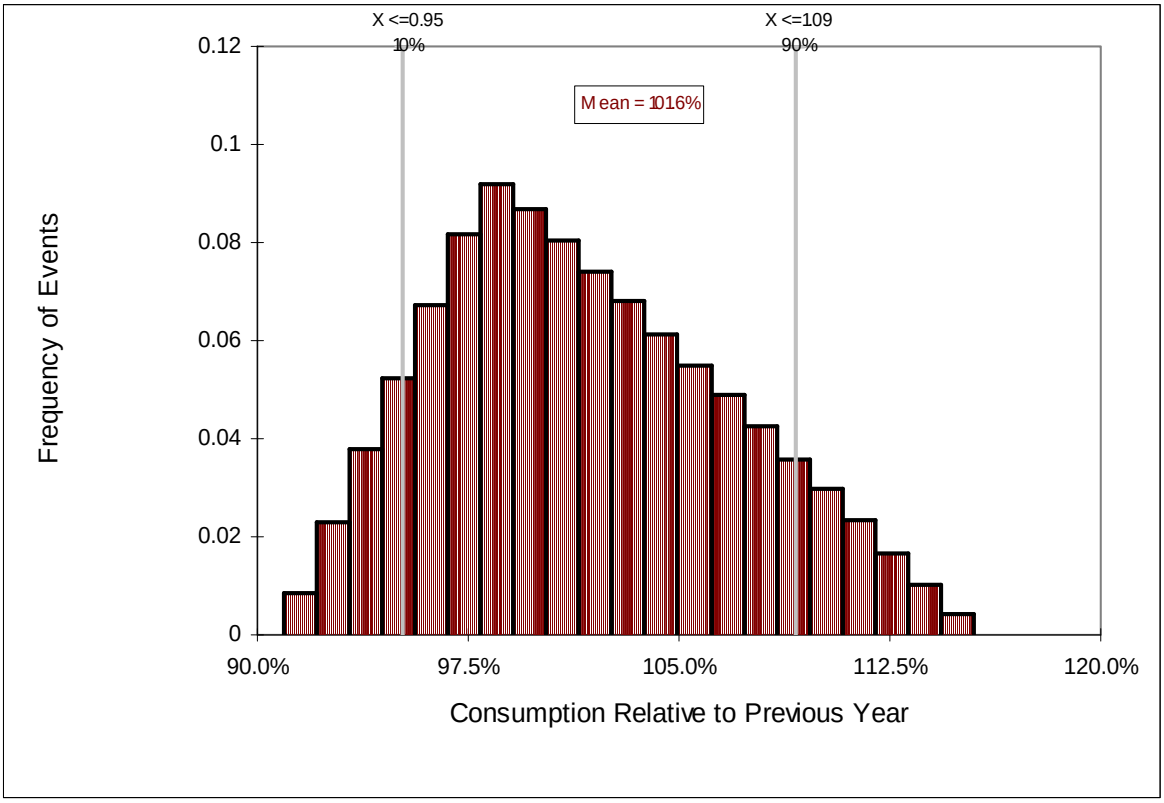
Graph 10: Industrial Load Growth Trend 1998 – 2007



The average annual growth from 1998 to 2007 was 1.62%; however, statistically no trend can be demonstrated from year to year due to significant variation.

For the Monte Carlo simulation, a triangular probability distribution of the industrial load growth was assumed for each year. For illustration, the distribution for the year 2027 is provided below. A triangular distribution is appropriate to describe a probability where values are not usually uniformly distributed. For the distribution the maximum value of a 15% annual increase was selected with a minimum value of a 10% annual decrease.

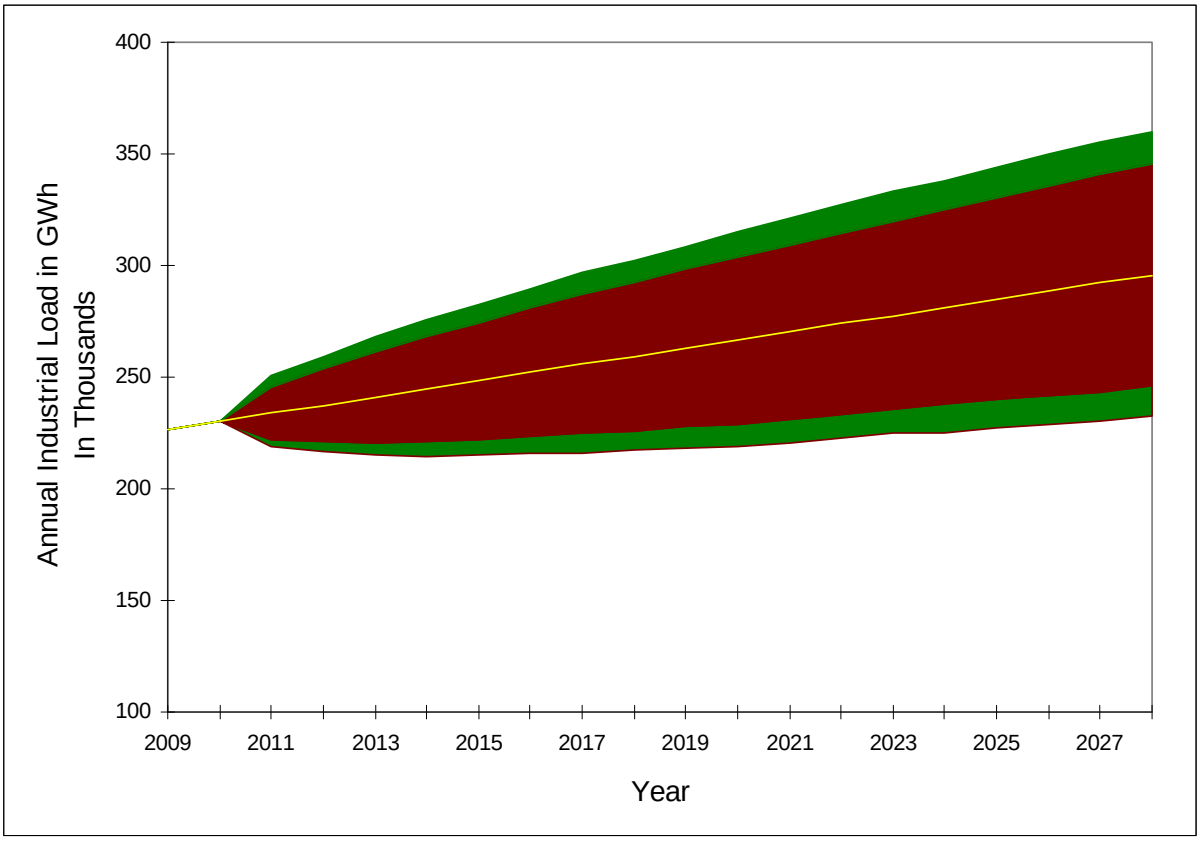
Graph 11: Probability Distribution for Industrial Load Percent Growth – 2027



The above graph indicates that for the year 2027, the Monte Carlo simulation used a probable annual consumption for that year of 101.6% over the previous year with the maximum being 115 percent over previous year and the minimum being close to 90% of the previous year. 80 percent of the inputs used for the Monte Carlo simulation were between a 95% to 109% compared to previous year.

Using these probability distributions each year over the planning period, the range for industrial load growth determined by the Monte Carlo Simulation is shown below.

Graph 12: Industrial Load GWh (2009 – 2028)



The above graph indicates that by 2028, the expected industrial load will be 296 GWh. The burgundy-shaded area indicates the 66% probability range that is for 2028 there is a 66% probability that the industrial load will be between 246 GWh and 346 GWh. The shaded area including both the burgundy and green areas indicates the 80% probability range that is for 2028 that the industrial load will be between 233 GWh and 360 GWh.

1.2 Energy & Peak Demand Forecast

The following figures and tables illustrate the long-term load forecast, excluding DSM activity, for energy and demand in the FortisBC service area for the 20-year forecast period of 2009 -2028.

This forecast is determined with a complex spreadsheet model, which uses the “drivers” described in Table 4 to estimate the Electricity Energy and Demand for each month and year for the forecast period.

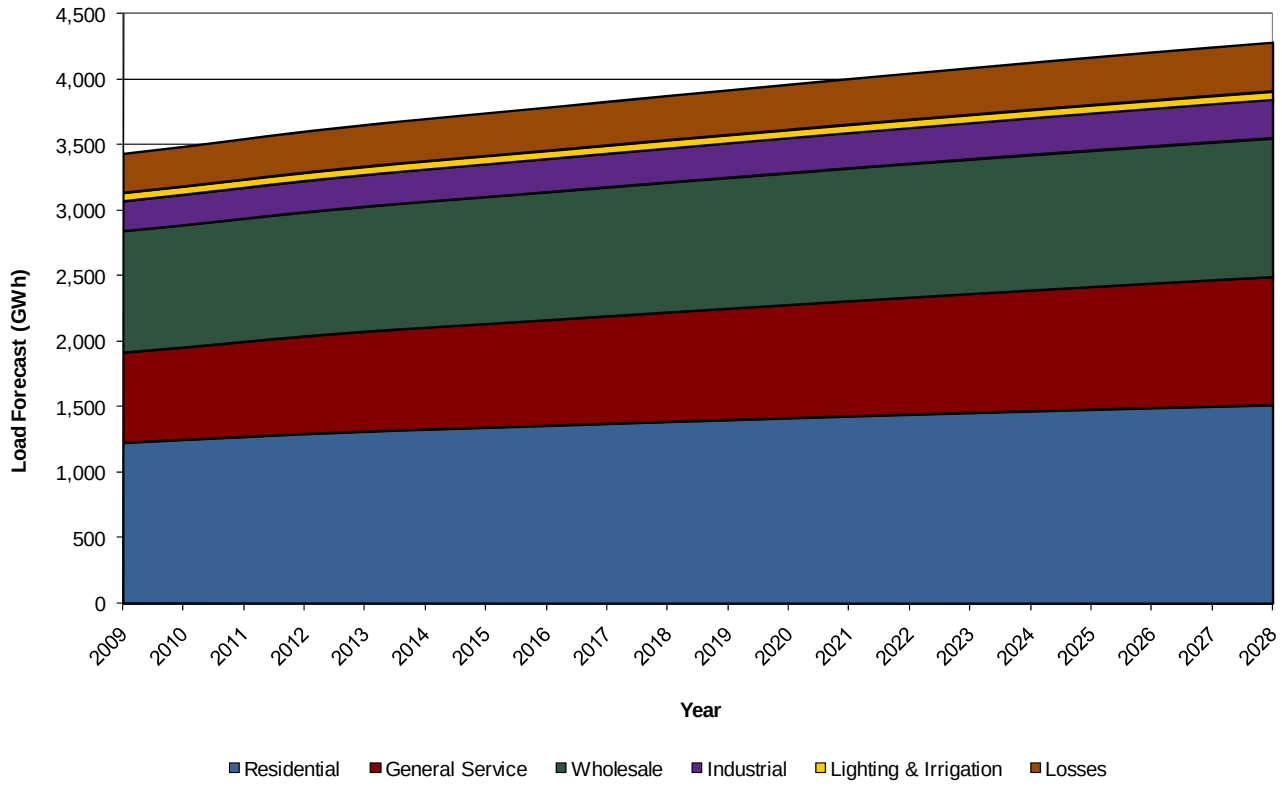
Growth is expected for the residential, general service, wholesale, and industrial customer groups over the forecast period, while lighting and irrigation energy requirements are forecast to remain constant.

The residential and general service energy sales are projected to grow over the 2009-2028 period at an average annual rate of 1.1 percent and 1.9 percent, respectively.

Graph 13 is the total energy load forecast for the FortisBC system through to 2028.

Graph 13 breaks up the total load into its component parts, as defined by customer segment.

Graph 13: FortisBC Energy-Load Forecast by Sector (GWh)



The table below indicates the forecast sales per category for milestone years.

Table 6: Forecast Sales per Sector (GWh)

	2009	2010	2015	2028
Residential	1,228	1,250	1,344	1,515
Commercial (General Service)	685	701	788	976
Industrial	227	230	248	296
Wholesale	929	936	971	1,060
Lighting & Irrigation	62	62	62	62
Losses	296	300	323	370
Total Load	3,426	3,480	3,736	4,278

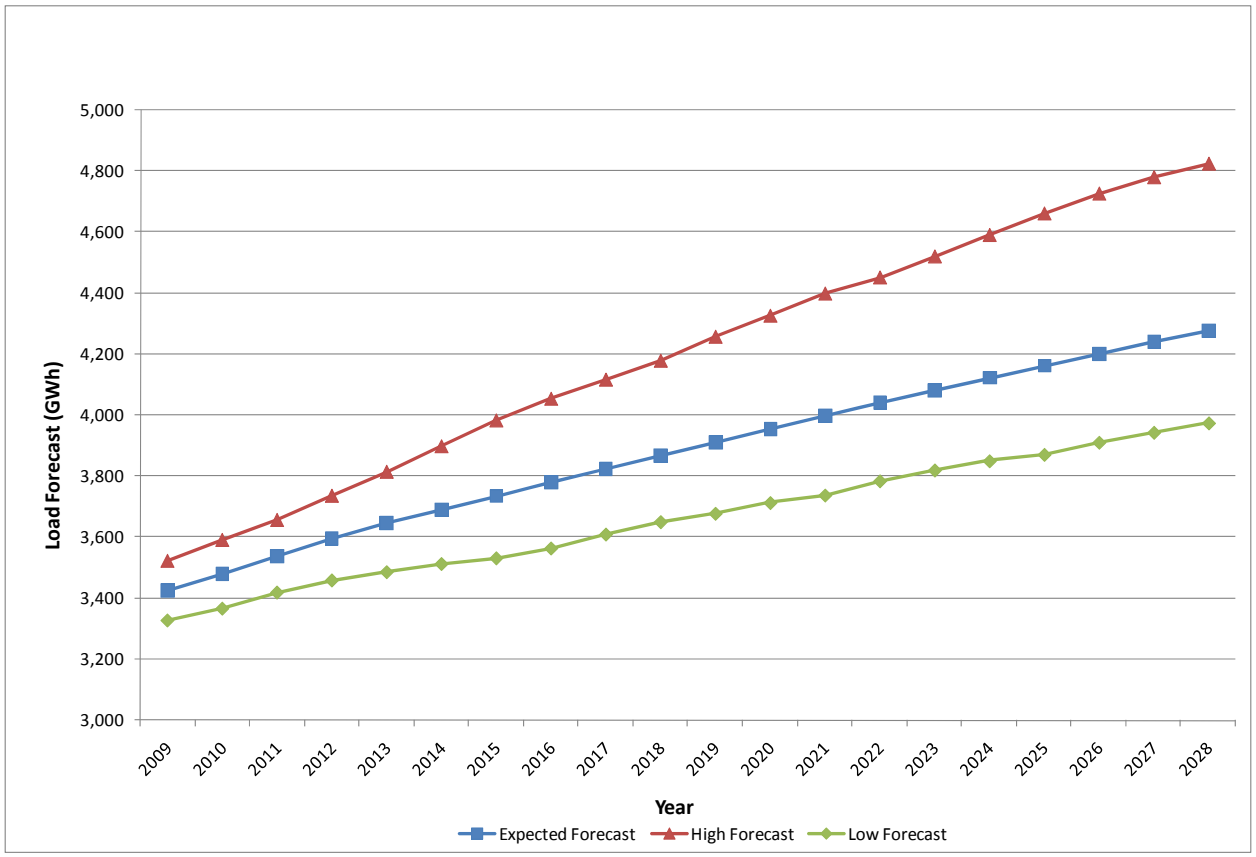
1.2.1 Energy Forecast Range

Future electricity requirements for a large and varied group of customers cannot be forecast exactly. It involves considering a number of variables such as population growth and the future electricity use per customer that is affected by many factors. It is reasonable however to estimate the probability that the forecast will be within a range of outcomes.

In order to account for the uncertainty in the Load Forecast, like BC Hydro and other utilities, FortisBC has developed High and Low Forecast scenarios based on a Monte Carlo analysis. Monte Carlo is a statistical approach that estimates a probability range by combining the probability of a number of variables that are the key drivers to a forecast determination.

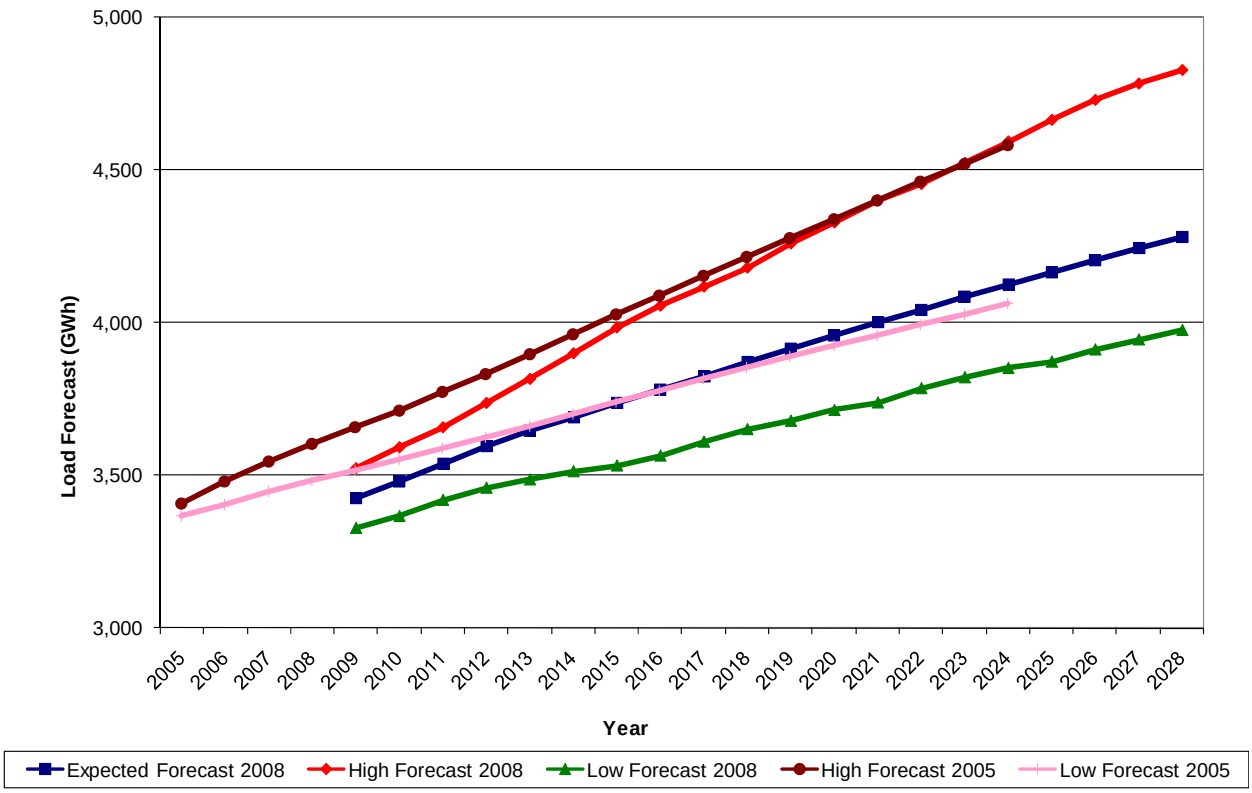
The graph below indicates the forecast range that was developed using the Monte Carlo simulation.

Graph 14: FortisBC Gross Load Forecast



Graph 15, below, compares the range of forecasts developed for FortisBC's 2005 Resource Plan with the current range of scenarios.

Graph 15: FortisBC 2005 RP vs. FortisBC 2008 RP Load Forecast



The table below provides the same information in tabular form.

Table 7: FortisBC 2005 RP vs. FortisBC 2008 RP Load Forecast

Year	Expected 2008	High 2008	Low 2008	Low 2005	High 2005
2005				3,385	3,407
2006				3,437	3,478
2007				3,491	3,546
2008				3,536	3,603
2009	3,426	3,524	3,329	3,578	3,656
2010	3,480	3,592	3,367	3,622	3,713
2011	3,538	3,657	3,420	3,668	3,772
2012	3,596	3,737	3,460	3,715	3,832
2013	3,647	3,815	3,487	3,763	3,895
2014	3,691	3,899	3,514	3,814	3,960
2015	3,736	3,984	3,532	3,864	4,026
2016	3,781	4,055	3,565	3,914	4,090
2017	3,825	4,117	3,610	3,963	4,154

Year	Expected 2008	High 2008	Low 2008	Low 2005	High 2005
2018	3,869	4,179	3,651	4,011	4,216
2019	3,913	4,258	3,678	4,058	4,278
2020	3,956	4,327	3,713	4,104	4,339
2021	3,999	4,400	3,738	4,149	4,399
2022	4,041	4,453	3,785	4,195	4,460
2023	4,083	4,522	3,820	4,240	4,520
2024	4,123	4,592	3,851	4,286	4,581
2025	4,163	4,662	3,872		
2026	4,203	4,728	3,911		
2027	4,241	4,781	3,944		
2028	4,278	4,826	3,975		

1.2.2 Peak Demand Forecast

Peak Demand growth is mainly dependent upon load growth and temperature conditions in any given year. FortisBC is considered a winter peaking utility, with the coldest period during the winter determining the peak as opposed to the hottest period in the summer.

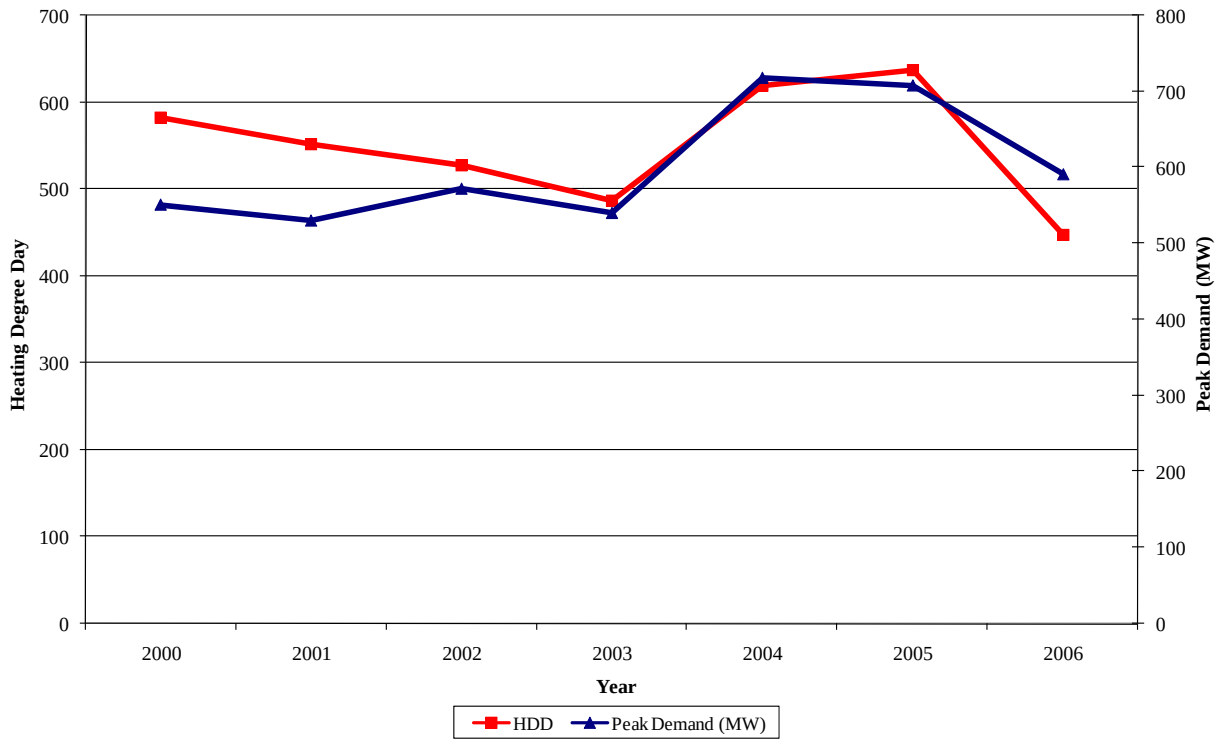
The peak demand forecast, and corresponding winter and summer seasonal peaks were developed from a review and averaging of actual system peaks and corresponding annual load increases for the period January 1996 to August 2008.

The exhibits below are plots of January and December Peak Demands versus Heating Degree Days (HDD)[1].

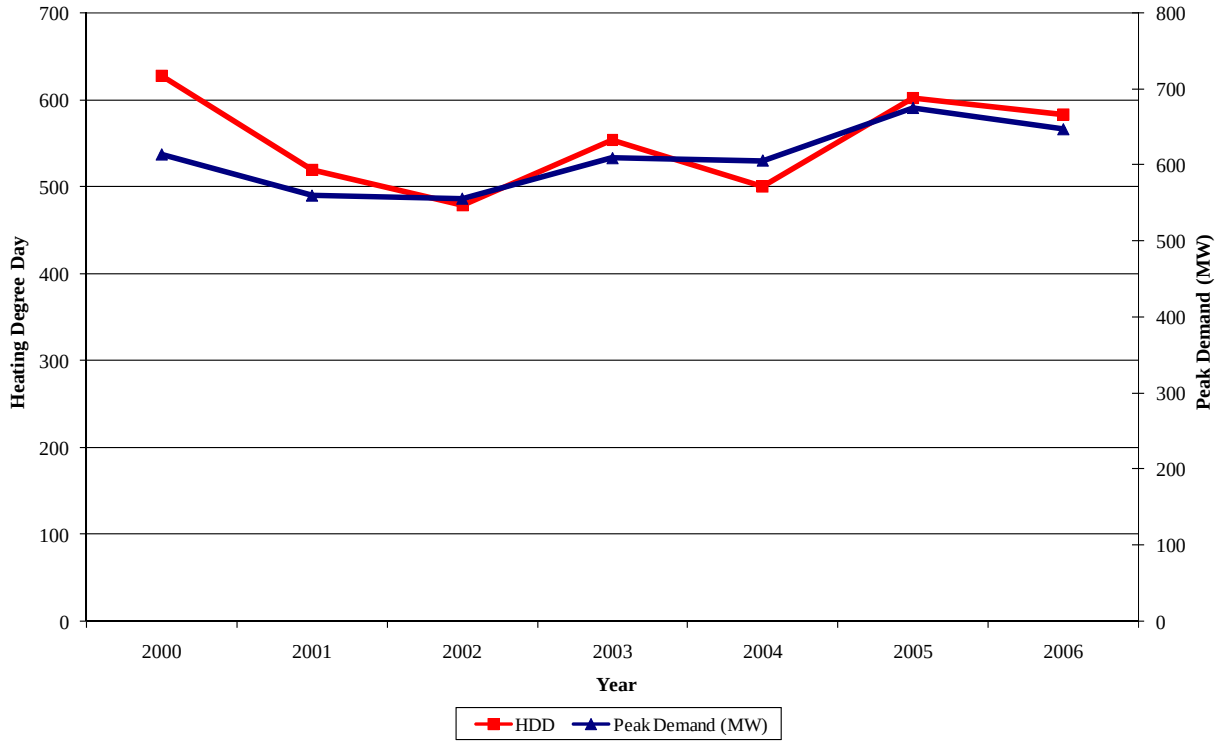
As the graphs below demonstrate, there is a good correlation between Heating Degree Days and Peak Demand.

[1]A Degree Day is a unit for estimating the demand for energy required for heating or cooling. The standard indoor temperature in Canada is considered to be 18ºC. For each 1ºC variation in average daily tmperature a heating or cooling degree-day is recorded. For example, if the average outside temperature for a day was 16ºC, it is recorded as 2 heating degree-days (HDD) or if it was 20ºC, it is recorded as 2 cooling degree-days (CDD).

Graph 16: Peak Demand versus Heating Degree Days - January



Graph 17: Peak Demand versus Heating Degree Days - December

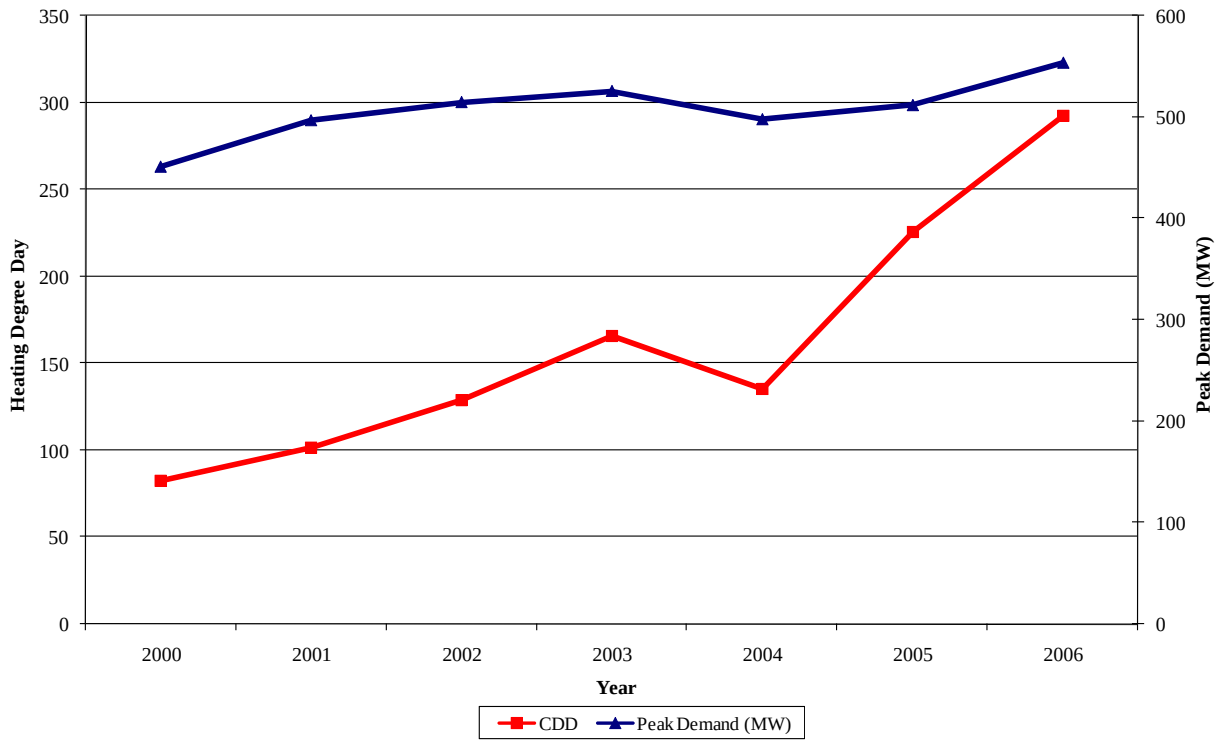


The peak demand that occurs in the summer months also needs to be considered. Summer peak demand is affected by rising temperatures and the level of Cooling Degree Days (CDD)[2]. The CDD measurement is used to determine the amount of cooling that a building needs based on the ambient temperature relative to a base level of 18ºC).

[2] See footnote [1].

The following graph demonstrates the correlation between CDDs and peak load during July.

Graph 18: Peak Demand versus Cooling Degree Days – July



Over longer time periods, there is a reasonable correlation between annual energy growth and Peak Demand growth. The table below plots annual net energy growth versus peak winter demand growth.

Table 8: Historical Winter Peak Demand and Annual Energy Growth

Year	Peak Demand (MW)	Annual Net Energy (GWh)
1996	667	3,062
1997	640	2,915
1998	630	2,886
1999	548	2,923
2000	614	2,993
2001	560	3,026
2002	572	3,126
2003	609	3,182
2004	718	3,229
2005	708	3,346
2006	718	3,403
2007	683	3,246
2008	746	3,400

Considering the short-term impacts of temperature and the long-term effect of load growth the following approach was used to forecast Peak Demand over the planning period:

The historical peak demand for each month in each year from 1996 to 2008 was used to establish a set of baseline values. These baseline values were then multiplied by the actual and forecast load growth. For example, the peak demand in January 1996 was 667 MW and the actual and forecast energy load growth between 1996 and 2008 is 27%. Accordingly the forecast peak demand value for January 2008, based on January 1996 was calculated to be 1.27 X 667 = 848. Using January 1997 which had a peak demand in January of 640 MW and a load growth between 1997 and 2008 of 25%, the forecast peak demand for 2009 using 1997 as the base was calculated to be 1.25 X 640 = 798 MW. The table below indicates how this procedure was used to develop eleven forecast values for the peak demand for January 2009 and an average of the eleven values, and also demonstrates this procedure in arriving at the January 2009 forecast.

Table 9: Peak Demand Estimate for January 2009

Baseline Month	**Jan-98**	**Jan-99**	**Jan-00**	**Jan-01**	**Jan-02**	**Jan-03**	**Jan-04**	**Jan-05**	**Jan-06**	**Jan-07**	**Jan-08**
Baseline Peak MW	630	548	551	530	572	540	718	708	591	683	663
Growth Factor	1.20	1.19	1.15	1.13	1.11	1.09	1.08	1.04	1.02	1.01	0.99
Forecast Value January 2009 MW	756	651	636	600	635	589	774	738	601	688	656
Average Forecast Value January 2009 MW											**666**

Using this procedure a Peak Demand was forecast for each month over the forecast period and the results are given in the following table.

Table 10: Peak Demand Base Forecast (MW)

	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Peak
2009	701	600	550	492	455	495	560	538	454	519	613	666	701
2010	712	609	559	500	462	502	568	547	461	527	622	676	712
2011	724	619	568	508	470	511	578	556	468	536	632	687	724
2012	736	630	578	516	478	519	587	565	476	545	643	699	736
2013	746	639	586	524	485	527	596	573	483	553	652	709	746
2014	755	646	593	530	491	533	603	580	489	559	660	717	755
2015	764	654	600	537	497	539	610	587	495	566	668	726	764
2016	774	662	607	543	503	546	618	594	501	573	676	735	774
2017	783	670	615	549	508	552	625	601	507	580	684	743	783
2018	792	678	622	556	514	559	632	608	513	586	692	752	792
2019	801	685	629	562	520	565	640	615	518	593	700	760	801
2020	810	693	636	568	526	571	647	622	524	600	707	769	810
2021	819	700	643	575	532	578	654	629	530	606	715	777	819
2022	827	708	650	581	537	584	661	635	536	613	723	786	827
2023	836	715	656	587	543	590	667	642	541	619	730	794	836
2024	844	722	663	593	548	596	674	648	547	625	738	802	844
2025	852	729	669	598	554	602	681	655	552	631	745	810	852
2026	860	736	676	604	559	607	687	661	557	637	752	817	860
2027	868	743	682	610	564	613	694	667	562	643	759	825	868
2028	876	750	688	615	569	618	700	673	567	649	766	832	876

The Monte Carlo simulation for the energy load forecast developed a forecast range over the planning period for the energy load. This same forecast range was applied to the Expected Peak Demand Forecast. This forecast range is expressed in graphical and tabular form in the figures below.

Graph 19: FortisBC Peak Demand Forecast

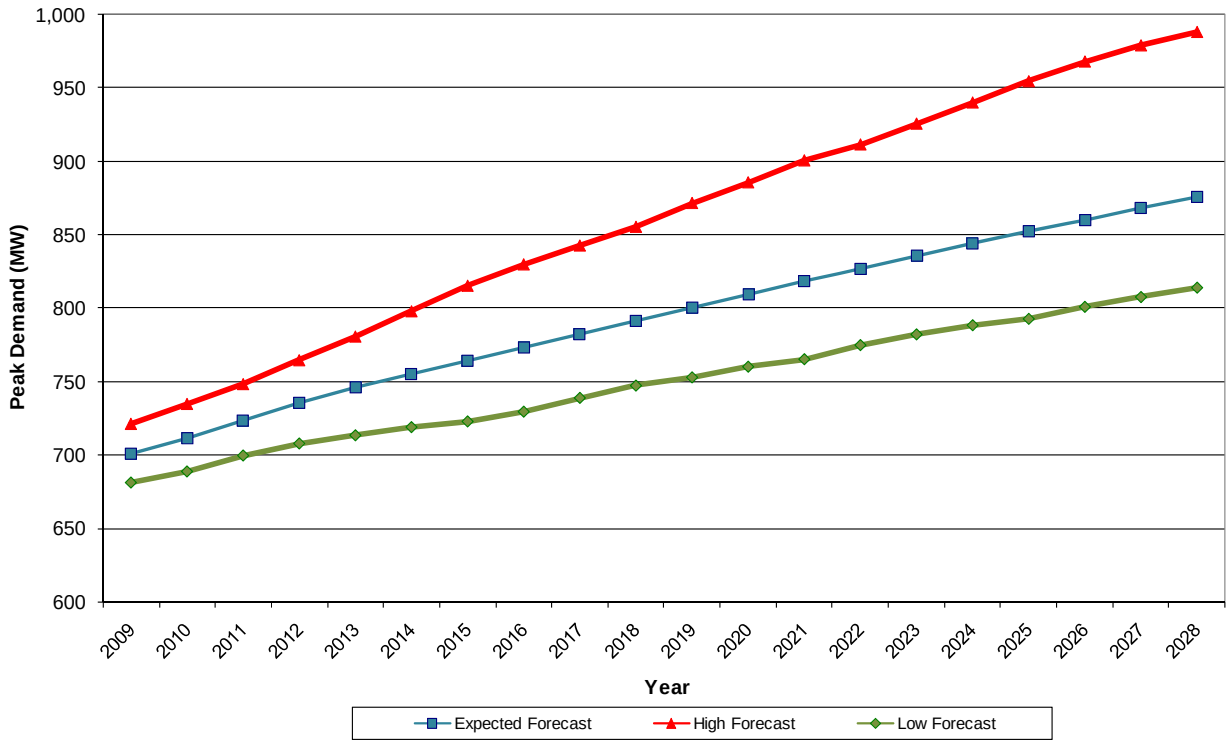


Table 11: FortisBC Annual Peak Demand Forecast (MW)

Year	Low Forecast	Expected Forecast	High Forecast
2009	681	701	721
2010	689	712	735
2011	699	724	748
2012	708	736	764
2013	713	746	780
2014	719	755	798
2015	723	764	815
2016	729	774	830
2017	739	783	843
2018	747	792	855
2019	753	801	871
2020	760	810	886
2021	765	819	901
2022	775	827	911
2023	782	836	926
2024	788	844	940
2025	793	852	955
2026	801	860	968
2027	808	868	979
2028	814	876	988

The expected forecast growth over the planning period is 25.0%, with the expected forecast peak being 876 MW in 2028. The 2028 peak demand forecast using the high forecast as the base is 988 MW and the corresponding 2028 low peak demand forecast is 814 MW.

1.2.2.1 Peak Demand Forecast on a Seasonal Basis

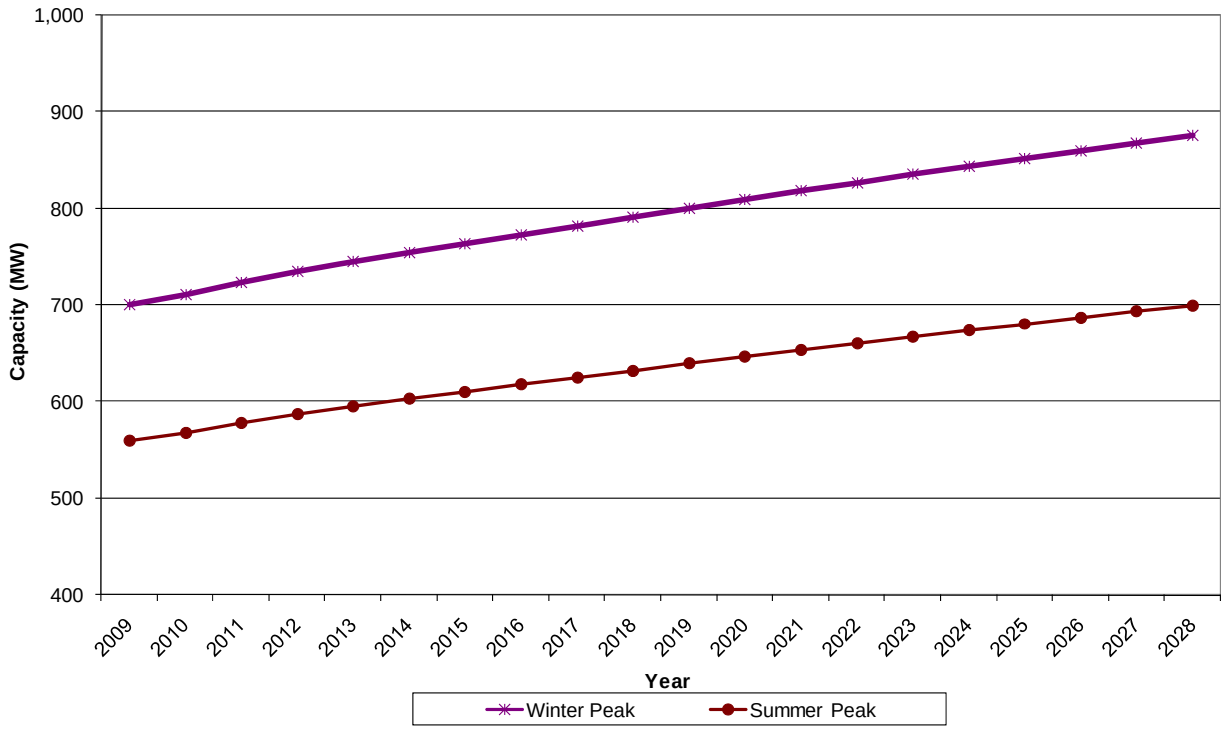
The approach used above for determining the expected Peak Demand forecast uses a monthly process whereby the Januarys, for example, are all compared. The result is that the annual peak from a forecast perspective is designated as being in January. Historically though, the peak has occurred in December, or November (as in 2006). Similarly, the hottest day in the summer occurs in either July or August.

Therefore, a supplementary approach involves using the same procedure as was used in determining the Expected Peak Demand but instead of using month over month, the approach uses annual season over season. The result is a Seasonal Peak Demand Forecast, illustrated in both tabular and graphical form in the Figures below.

Table 12: FortisBC Seasonal Peak Demand Forecast (MW)

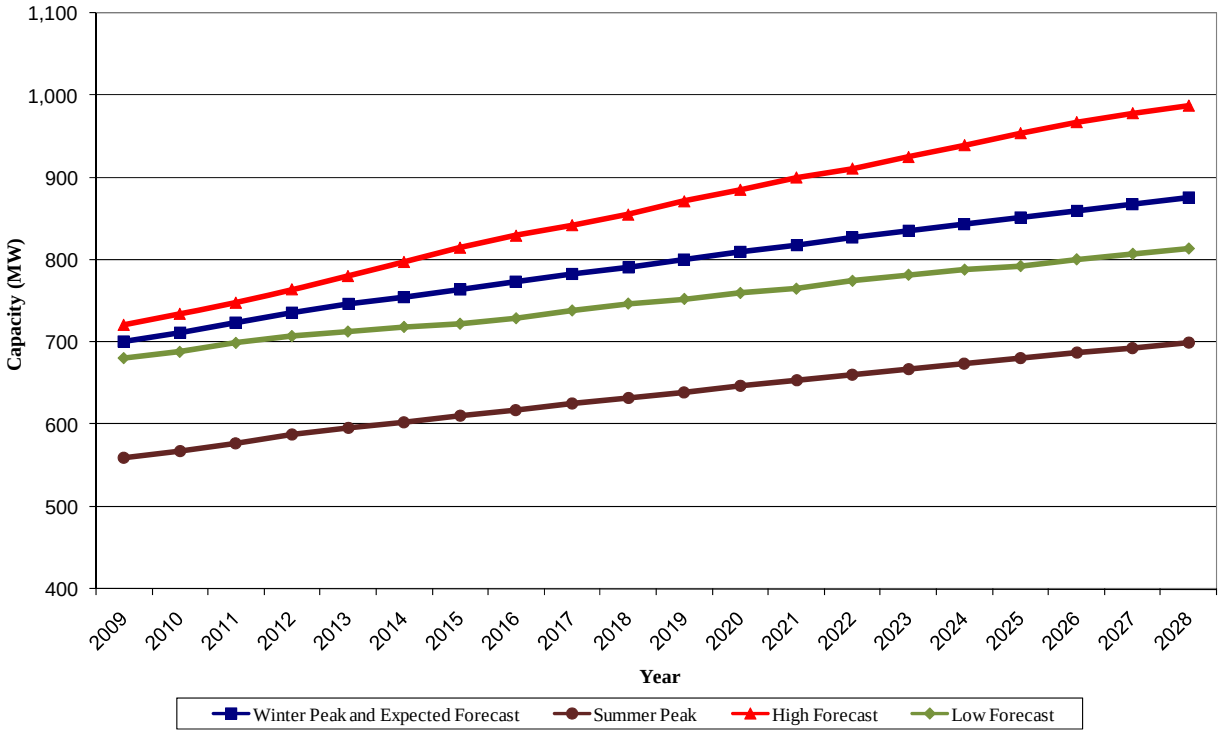
Year	Winter	Summer
2009	701	560
2010	712	568
2011	724	578
2012	736	587
2013	746	596
2014	755	603
2015	764	610
2016	774	618
2017	783	625
2018	792	632
2019	801	640
2020	810	647
2021	819	654
2022	827	661
2023	836	667
2024	844	674
2025	852	681
2026	860	687
2027	868	694
2028	876	700

Graph 20: FortisBC Seasonal Peak Demand Forecast (MW)



The graph below illustrates the Expected Peak Demand Forecast, the Low Forecast and the High Forecast based on the Monte Carlo simulation range and the Winter and Summer Peaks.

Graph 21: FortisBC Seasonal Peak Demand Forecast Ranges



As the graph indicates the Winter Peak generally falls within the Forecast range. The Resource Planning model utilizes the Expected Peak Demand forecast and the Low and High range values for analyzing forecast scenarios.

1.2.3 Forecast Uncertainty

The Load Forecast is uncertain due to:

1. Variability in the Key Drivers, identified in Table 4.
2. Potential inaccuracies in the assumed relationships between the Key Drivers and the FortisBC system Load, and,
3. Factors not considered in the Forecast Model, which may have an impact on load growth
    - An example which would result in a lower than expected forecast would be an unexpected severe economic downturn;
    - an example which would result in a higher than expected forecast would be a significant market penetration of electric vehicles.

Considering the uncertain items above, FortisBC developed a range of uncertainty around the reference Forecast.

The uncertainties were analyzed using Monte Carlo simulation methods and the @Risk software package[3]. The Monte Carlo simulation method is a technique for estimating probabilities of an outcome as defined by a model. The model in this case was the spreadsheet model used to derive the load forecast based on the Forecast Drivers identified in Exhibit 6.02.

A probability distribution for the load forecast was obtained which showed the likelihood of various load levels resulting from the combined effect of the different Forecast Drivers.

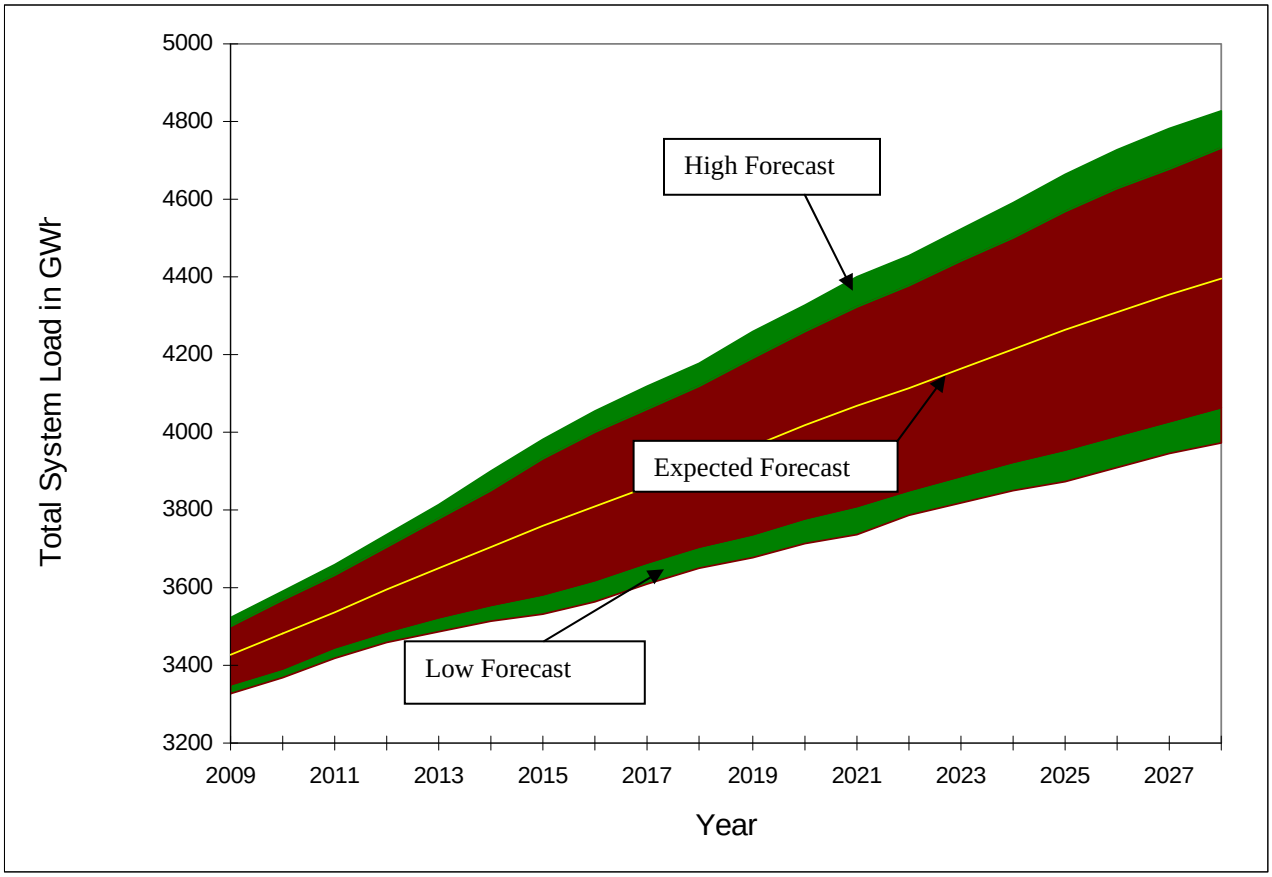
The complete simulation run for the period was used to develop a forecast range, which is bounded by:

- A low scenario: There is a 10 per cent chance the outcome will be below this value.
- A high scenario: There is a 10 per cent chance that the outcome will exceed this value.

The graph below indicates the forecast range developed by the Monte Carlo simulation process for the complete planning period.

[3]@RISK for Excel Version 4.5.7 (US/English) March 2007. Palisade Corporation. @RISK 4.5 is a Monte Carlo simulation add-in for Microsoft Excel version 2000 (9.0) or higher.

Graph 22: FortisBC Load Forecast Range 2009 – 2028



The burgundy-shaded area indicates the range included within plus or minus one standard deviation; based on the simulation process, there is a 66% probability that the forecast will be within this range. There is an 80% probability that the forecast will be within the burgundy and green shaded areas.

Dennis Swanson
Director, Regulatory Affairs

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December 29, 2008

Ms. Erica M. Hamilton
Commission Secretary
BC Utilities Commission
Sixth Floor, 900 Howe Street, Box 250
Vancouver, BC V6Z 2N3

Dear Ms. Hamilton:

Re: FortisBC Inc. 2008 Strategic Demand-Side Management Report and DSM Monitoring and Evaluation Plan 2009 through 2011

In its 2009 – 2010 Capital Expenditure Plan, FortisBC Inc. ("FortisBC" or the "Company") committed to file a Strategic Demand-Side Management ("DSM") Report and a Monitoring and Evaluation Plan for 2009-2011 ("M&E Plan"), both of which are attached.

These documents are filed for informational purposes only. The DSM Report provides a strategic framework for the Company's PowerSense Program, which will be further developed in a comprehensive Long-Term 2011-2020 DSM Plan ("2011 DSM Plan"), expected to be submitted for Commission approval during 2010. The M&E Plan outlines the monitoring and evaluation studies that will be conducted during 2009 – 2011.

The attached documents are also being provided to the members of FortisBC's DSM Advisory Committee for review and to Registered Intervenors in the 2009 – 2010 Capital Expenditure Plan proceeding for information.

The Company also intends to file its Monitoring and Evaluation Report early in 2009.

Sincerely,

(J. Martin for)

Dennis Swanson
Director, Regulatory Affairs

FORTISBC INC.

STRATEGIC DEMAND-SIDE MANAGEMENT REPORT

DECEMBER 2008

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Strategic Demand-Side Management Report

Introduction

FortisBC Inc. ("FortisBC" or "the Company") is an integrated regulated electric utility that generates, transmits and distributes electricity in the southern interior of British Columbia. The Company serves over 155,000 customers directly and indirectly, focusing on the delivery of safe, reliable and cost effective electricity. This represents approximately 8.1 percent of British Columbia's electric utility customer total[1], and about 6.1 percent[2] of total provincial domestic load.

Operating continuously since 1897, FortisBC had revenues of $209 million in 2007 from sales of 3,410 GWh. FortisBC's peak capacity requirement was 746 MW in December 2008, and a new summer peak requirement record of 569 MW was set in July 2007. The Company owns four hydroelectric generating plants located on the Kootenay River between Nelson and Castlegar, B.C., with a combined installed capacity of 223 MW and approximately 6,750 kilometres of transmission and distribution power lines.

The FortisBC PowerSense demand-side management ("DSM") program has operated since 1989. The PowerSense program is established on the principle that it is less expensive to fund programs that reduce energy consumption than it is to purchase the energy or build new generation. PowerSense programs exist for the major customers classes: residential, commercial and industrial. Customers of municipal utilities that purchase wholesale power from FortisBC also directly receive the same PowerSense services from FortisBC.

PowerSense is a successful program, delivering a total of over 300 GWh of energy savings and collecting several awards, including a 2000 BC Minister of Environment Award and a 2003 Canadian Energy Efficiency Award from the federal government. FortisBC remains committed to energy efficiency and intends to meet the provincial government's *2007 BC Energy Plan: A Vision for Clean Energy Leadership* ("Energy Plan") goal of reducing electrical load growth by 50 percent with DSM.

In addition to the various policy actions influencing DSM identified in the Energy Plan, the provincial government in 2008 passed amendments to the Utilities Commission Act ("UCA") that provide guidance for utility DSM programs to the British Columbia Utilities Commission ("BCUC").

DSM programs will become increasingly valuable as energy and capacity market purchases increase with load growth. Currently, FortisBC has a relatively small energy deficit and a more considerable capacity shortfall, and both are forecast to increase in the future.

[1] FortisBC / (BC Hydro + FortisBC) customer count. BC Hydro numbers from their 2006 annual statement.

[2] FortisBC / (BC Hydro + FortisBC) gross load (GWh). BC Hydro numbers from their 2006 annual statement.

Purpose of this Document

Evolving customer and government expectations and the increasing risk related to purchasing power necessitates a review of the PowerSense program.

Specifically, this document analyzes the changing environmental factors affecting DSM and provides clear objectives for the development of a detailed plan that will guide PowerSense programs over the years 2011-2020. This fulfills the commitment made in the 2009/2010 Capital Expenditure Plan to provide a Strategic DSM Report (also referred to as a Strategic DSM Plan). DSM strategy is also a key input to FortisBC's long term Resource Plan, expected to be filed in 2009.

PowerSense Background

FortisBC PowerSense has been operating since 1989 offering information and efficiency incentives to customers. PowerSense has a number of programs within each of the residential, general service and industrial sectors, providing conservation-based energy savings through improved energy use efficiency and energy use reduction. Average 2000-2007 annual savings acquisition attributed to these DSM programs activities has offset 26 percent of annual load growth.

Between 1989 and 2007, FortisBC customers saved 301 gigawatt-hours (GWh) of energy and have avoided 38 megawatts (MW) of capacity requirements for power. The investment (incentives and program costs) in DSM measures of $33 million by FortisBC and related contributions of $30 million by FortisBC customers since 1989 has been offset by $94 million of avoided power purchase costs. DSM program performance has yielded a benefit-cost ratio of 1.5 since inception.

2006 DSM Plan

In September 2005, FortisBC completed and filed the *Efficiency Savings and Demand Reduction Potential* study ("2005 Efficiency Potential Study"). The 2005 Efficiency Potential Study provided input to the preparation of the *2006-2010 Demand Side Management Five Year Business Plan* ("2006 DSM Plan"), filed in October 2005. The 2006 DSM Plan provided the basis for the annual savings targets and planned expenditures filed in the *2009/2010 Capital Expenditure Plan* for each program and customer sector.

The 2006 DSM Plan identified the energy efficiency or demand side management market within the company's service area and described the programs selected to deliver efficiency-related savings to customers over the 2006-2010 period.

The 2006 DSM Business Plan development relied on customer load and end use information, a review of available efficiency technologies and expected regulation changes presented in the 2005 Efficiency Potential Study. The 2005 Efficiency Potential Study estimated 294 GWh of available savings potential for the period 2004 to 2013. The target of 81 GWh was 27 percent of the available potential for the period.

Table 1a provides a summary of the market potential and the target savings amounts for the five years of the 2006 DSM Plan.

Table 1a: Market Potential and 2006 DSM Plan

Sector	Market Potential	2006-2010 DSM Business Plan	
	(GWh)	(GWh)	% of Potential
Residential	83.5	28.2	34
General Service	178.5	43.5	24
Industrial	32.4	8.8	27
Total	**294.4**	**80.5**	**27**

Table 1b presents the forecast results for the same period based on actual savings to the end of 2007 and forecast annual savings for 2008-2010.

Table 1b: 2006 DSM Business Plan and DSM Performance

Sector	2006-2010 DSM Business Plan	Forecast	
	(GWh)	(GWh)	% of Business Plan
Residential	28.2	58.9	209%
General Service	43.5	57.6	133%
Industrial	8.8	13.0	146%
Total	**80.5**	**129.5**	**161%**

Forecast: Sum of Actual 2006 & 2007, Projected 2008, and Forecast 2009 & 2010 Energy Savings

2009-2010 Capital Expenditure Plan

In response to the Energy Plan and power supply constraints, FortisBC filed as part of the 2009-2010 Capital Expenditure Plan a request for increased DSM funding. If approved, this level of expenditure will result in increased energy savings by the end of 2010 by providing:

- Higher incentive levels for new and/or existing programs;
- New programs, such as support for solar hot water installations;
- Increased residential home retrofit program take-up due to the collaborative provincial LiveSmart BC program;
- Increased commercial sector savings as a result of the provincial Public Sector Energy Conservation Agreement, which will co-fund energy efficiency projects for public sector buildings throughout the service territory;
- An increased focus on DSM services, including a small business energy audit program and industrial energy efficiency workshops; and
- A increased focus on "Conservation Culture" through education and social marketing

The DSM Environment

The Energy Plan and the Utilities Commission Amendment Act (Bill 15-2008) have established policies and regulations that require utilities, where prudent to do so, to position DSM resources before all other resources when considering either the acquisition of new energy and capacity resources or additional energy purchases to meet customer load in long-term resource plans.

Energy Plan

The Energy Plan highlights the importance of DSM as a key component of future electricity supply. The specific Energy Plan objectives and policy actions influencing DSM programs for public utilities are:

- Set ambitious conservation targets to acquire 50 percent incremental resource needs through conservation by 2020 (Policy Action 1);
- Ensure coordinated approach to conservation and efficiency is actively pursued in British Columbia (Policy Action 2); and
- Encourage utilities to pursue cost effective and competitive demand side management opportunities (Policy Action 3).

UCA DSM Regulations

The passing of Bill 15-2008 allowed the creation of a Demand-Side Measures Regulation ("DSM Regulation") (issued November 7, 2008) that supports the Energy Plan and defines how the BCUC should determine whether a DSM program is "adequate" and "cost effective". The DSM Regulation will require that the next FortisBC DSM plan include the following to be "adequate":

- a demand-side measure intended specifically to assist residents of low-income households to reduce their energy consumption;
- a demand-side measure intended specifically to improve the energy efficiency of rental accommodations;
- an education program for students enrolled in schools[3]; and
- an education program for students enrolled in post-secondary institutions.

Education programs must focus on energy conservation and efficiency, and may include the funding of the development of such a program.

The DSM Regulation also specifies how the BCUC should assess "cost-effectiveness". In particular:

[3] A school regulated under the *School Act* or the *Independent School Act*

- demand-side measures may be evaluated by cost and benefit individually, or within a portfolio of other demand-side measures;
- the total-resource cost ("TRC") test must be provided, with the benefits inflated by 30 percent, for low-income programs;
- FortisBC must use the BC Hydro long-term marginal cost to calculate the benefit of avoided supply from BC Hydro;
- education programs, and any energy efficiency training, community engagement or technology innovation demand-side measures included in a DSM plan, must be evaluated for cost-effectiveness by testing the portfolio of measures in which they are included as a whole, and not the individual programs or measures;
- public awareness programs (programs that the BCUC believes will help the public conserve energy or increase program participation), must be evaluated for cost-effectiveness by testing the portfolio of measures in which they are included as a whole, and not the individual programs; and
- the rate-impact measure ("RIM") test may not be used to determine that a demand-side measure is not cost-effective.

UCA Long-term Resource and Conservation Planning Requirements

Section 44.1 (2) of the UCA requires that FortisBC file a long-term resource plan which includes the following related to DSM:

- an estimate of the load FortisBC would expect to serve in absence of demand-side measures;
- a plan for implementing demand-side measures and an estimate of the impact of those measures on the resource plan; and
- an explanation as to why any supply-side measures outlined in the resource plan could not be replaced by demand-side measures.

Customer Perceptions and Expectations

Customer expectations with respect to DSM programs remain high. Customer polling shows that a high percentage of Canadians strongly favour using energy efficiency and conservation programs to address the future electricity needs of their province, the highest of all the alternatives suggested. Surveys also show that only 69 percent of Canadians are satisfied with the information they receive from their utility regarding using electricity more efficiently and that 65 percent believe that their electric utility should be responsible for doing so (much higher than the next source at 15 percent).

There are indications that customers are increasingly environmentally aware as well. FortisBC has received increasing numbers of inquiries regarding net metering (which enables certain types of customer-owned generation) and has recently signed up its first "green power" customer. FortisBC's quarterly customer surveys show that the need for the company to operate in an environmentally responsible manner has increased in importance from eighth (lowest ranking) to third since the end of 2007.

As part of the development of the next FortisBC Resource Plan, the Company made presentations to 15 local government entities in its service territory. The presentation outlined the power supply and demand environment, various resource options under consideration, and portfolios of resources that may provide a solution to the forecast energy and capacity gaps. FortisBC also engaged the Environics Research Group, a nationally recognized opinion research organization, to assist in discovering and analyzing the customers' perspective.

FortisBC was advised that it must do all it can to encourage conservation efforts and DSM. These efforts should include advanced metering, enabling time-of-use rates and load control. The stakeholders also indicated that FortisBC should consider distributed generation resources such as solar, micro-hydro, bio-mass and co-generation.

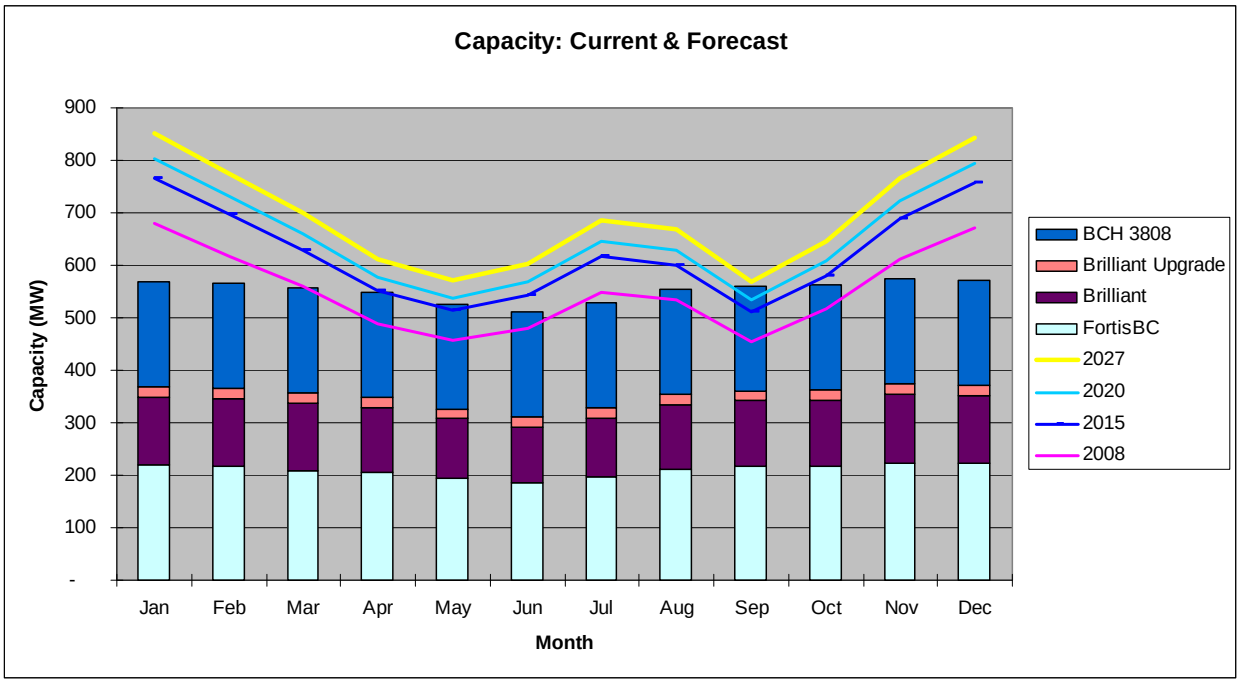
FortisBC Capacity and Energy Deficit

FortisBC has four dams on the Kootenay River, which, together with firm, long term Power Purchase Contracts with Columbia Power Corporation and BC Hydro provide a total winter peak capacity of approximately 551 MW (about 74 percent of FortisBC's 2008 winter peak capacity requirement of 746 MW) leaving a shortfall of about 195 MW. The peak capacity shortfall grows to approximately 265 MW in 2027. Further, while a peaking capacity shortfall is forecast only for six months in 2008, by 2012 a shortfall is forecast for nine months of the year, and by 2023 is forecast for every month of the year.

The energy shortfall associated with the capacity gap – currently at about 22 GWh (or 1 percent) of annual requirements – will grow to approximately 324 GWh (or 8 percent) by 2027.

Figure 1 graphically depicts the growing monthly gap between peak demand and available resources. The bars represent available resources, and the lines represent forecast peak demand, by month, for the years 2008, 2015, 2020, and 2027.

Figure 1: Monthly Peak Capacity: Current & Forecast



Rising and Uncertain Cost of Energy and Capacity

Currently, the capacity and energy deficit is met via reliance upon long-term power purchase contract and the short-term wholesale electricity market.

The Western Electricity Coordinating Council ("WECC") 2007 Power Supply Assessment states that specific to the "Canada" sub-region, summer capacity is expected to be sufficient until 2015, at which time current and currently planned resources no longer provide sufficient capacity. By 2016, it is forecast that Canadian winter capacity will be in deficit by about 2500 MW. In summary, the WECC's assessment of the ongoing availability of supply from the wholesale electricity market, and the reliability of that supply poses, in FortisBC's opinion, an unacceptable risk.

Electricity prices from the wholesale market are volatile. Since 2003, the Mid-Columbia Light Load Hour price per MWh has varied between $0 and $150, while Heavy Load Hour price per MWh has varied between $0 and over $400. Alberta Power Pool price volatility was more significant. With the growing forecast capacity and energy gap and uncertainties in load, the resulting potential price excursions are an unacceptable economic risk.

Energy from the wholesale market within the WECC area is available from primarily thermal generators. To supply FortisBC's shortfall over 20 years would equate to the production of approximately 928,000 metric tonnes of greenhouse gases. FortisBC believes there are better alternatives available, including DSM resources.

Technological Change

PowerSense has generally been supportive of energy efficiency technologies that are at the early stage of consumer adoption. For example, FortisBC has provided incentives for compact fluorescent light ("CFL") bulbs, light-emitting diode ("LED") holiday lights, air-source heat pumps and energy-efficient motors.

New technologies are emerging that will not only reduce the energy use of existing devices, but will also allow customers and the company to control and monitor energy use in ways not possible in the past. Advanced metering (also know as smart metering) systems are perhaps the biggest technological advance in this regard.

Goals

The overall impact of the environmental factors listed above is significant. While the 2009-2010 DSM program is expected to drive further energy efficiency results by the end of 2010, FortisBC intends to further enhance the program in 2011 and beyond.

The 2011-2020 DSM Plan ("2011 DSM Plan") must address all the environmental factors influencing DSM programs. The manner in which these factors are to be addressed in the 2011 DSM Plan will be guided by a number of specific objectives.

Objectives

Having clear objectives for the 2011 DSM Plan will enable stakeholders to assess the success of the plan and will describe the intermediate steps that must be taken to reach the identified goal.

Address Energy Plan Policy Actions

50 percent Target and Cost-Effective Demand-Side Management

FortisBC intends to meet 50 percent of its incremental energy requirements for the period 2008-2020 through DSM measures. Although the 50 percent objective may be achieved through a combination of DSM programs, codes and standards, and conservation rates, the 2011 DSM Plan will target meeting this objective with DSM programs only.

Table 2 presents the total estimated energy savings required to achieve the 50 percent target by the year 2020. The 2008 Revenue Requirements load forecast estimates a load growth of 573.4 GWh over the period, resulting a requirement for 286.7 GWh of DSM resource acquisitions. Table 2 presents an example of how the 286.7 GWh target may break down by customer class.

Table 2: 2008-2020 Energy Efficiency Targets by Customer Class

Customer Class	Energy Efficiency (GWh)
Residential	125.5
General Service	126.4
Industrial	34.8
Total Target	**286.7**

The customer class estimates indicated in Table 2 are useful starting points for program development. Actual targets for each customer class will be articulated within the 2011 DSM Plan.

In order to achieve the energy reductions required to meet the 50 percent objective (at minimum), detailed interim targets must be provided.

Objective 1: The 2011 DSM Plan should provide a forecast for achieving the 50 percent target on an annual basis, broken down by customer class.

Objective 2: The 2011 DSM Plan should provide TRC calculations for all programs on an individual, sector and portfolio basis.

Coordinated Approach

Energy Plan Policy Action 2 requires a coordinated approach to conservation and efficiency. To that end FortisBC is currently involved in a number of collaborative initiatives, including LiveSmart BC, Net Zero Energy Housing and the Public Service Energy Conservation Agreement, and will actively pursue other opportunities to work with the municipal, provincial and federal governments and other public utilities. In addition, the FortisBC DSM offerings will be aligned with future regulatory standards of energy devices and building codes to accelerate the market transformation to a point where regulation can take place.

Objective 3: The 2011 DSM Plan must include a listing of collaborative demand-side measures, including:

- New initiatives;
- Existing initiatives; and
- A description of how FortisBC will participate in the planned provincial government 2010/11 all-fuels CPR update, including budget cost to participate.

Meet Legislative Requirements

Awareness and Education

The DSM Regulation encourages utilities to include awareness and education initiatives in their DSM programs. Therefore:

Objective 4: The 2011 DSM Plan should describe how FortisBC will:

- Lead by example in energy reductions and promote conservation procurement policies in its operations;
- Implement a cost-effective community-based social marketing campaign targeting the residential sector;
- Implement a cost-effective community-based social marketing campaign targeting the small business and commercial/industrial sectors;
- Assess adequacy of existing education programs and opportunities for schools throughout the service area; and
- Introduce cost-effective education programs and opportunities for post-secondary schools and institutions throughout the service area.

Low Income Program

FortisBC believes it is important that all customers be able to participate in DSM programs, and the DSM Regulation requires low-income measures as part of its "adequacy" requirement.

Objective 5: The 2011 DSM Plan will include details of a low-income program which will:

- develop and seek partnerships with municipal, provincial and federal agencies and non-profit organizations to leverage investment and align service and program delivery;
- distribute benefits throughout the geographic service areas, including remote and aboriginal communities;
- minimize cost to low-income participants; and
- ensure programs are straightforward from the perspective of the low-income participant.

Program development should consider three components: energy efficient retrofits, resident education and awareness, and energy efficient new construction investment.

Rental Accommodation Program

Low income customers typically reside in social housing, in single-family homes, and in private rental accommodation. The greatest concentration of low-income residents is in social housing, while the largest number live in private rental units.

Objective 6: The 2011 DSM Plan should specify how PowerSense will assist the private rental market by:

- identifying its energy use and conservation potential;
- considering survey/focus group studies to engage landlords and further define needs;
- supporting targeted technical evaluation, testing and demonstration;
- supporting training of property managers and contractors;
- developing DSM incentives and information for building owners;
- working with landlords to develop effective means of engaging tenants in conservation action and behaviour;
- considering targeted, short-term financial incentives for small landlords and low-income households; and
- considering targeted, short-term financial incentives for tenants to support conservation action and behaviour.

Stakeholder Involvement

Stakeholder involvement is critical to achieving the overarching DSM goals and objectives as it will assist in bringing full understanding of the challenges and opportunities available. An appropriate forum for sharing ideas and concerns will ultimately provide a more comprehensive decision process and decision criteria.

Presently, FortisBC seeks advice and input from the Demand-Side Management Public Advisory Committee ("DSMPAC"), comprised of members from the institutional, industrial, commercial, governmental and public sectors, on various issues regarding energy conservation and efficiency. These include program design and expenditures, incentive approvals, report reviews and measurement and evaluation. As well, members provide outreach to a broader group of stakeholders and help facilitate linkages to sector specific opportunities for energy efficiency.

With changes to overall DSM goals and objectives, program development over the timeframe of the strategic plan will affect new and more stakeholder groups. Additionally, programs will likely be more complex and larger in scale than implemented in the past. It is recognized that broader consultation and participation may be required in the future.

Objective 7: Ensure meaningful and appropriate consultation with the DSMPAC in regards to PowerSense program changes, and engage broader stakeholder groups as appropriate.

Determine the Value of Energy Efficiency and Demand Response Programs

Marginal Cost of Energy and Capacity

The DSM Regulation specifies that FortisBC must use the BC Hydro long-term marginal cost to calculate the benefit of avoided supply from BC Hydro. For consistency and to ensure that the benefits of DSM measures are appropriately valued over their useful life, the 2011 DSM Plan must use a FortisBC long-term marginal cost of energy and capacity when calculating DSM benefits.

Objective 8: The 2011 DSM Plan will utilize a blended long-term marginal cost of energy and capacity when calculating DSM benefits using:

- the BC Hydro long-term marginal cost of energy and capacity when valuing avoided supply from BC Hydro, and;
- a FortisBC long-term marginal cost of energy for valuing avoided supply from sources other than BC Hydro.

Develop Conservation Potential for Energy and Capacity

Developing the 2011 DSM Plan will require research and investigation by FortisBC to prepare a forecast of potential for conservation and energy efficiency savings and demand reduction in the Company's service area.

Objective 9: The 2011 DSM Plan should include:

- a conservation and energy efficiency potential study for each customer class;
- preliminary investigation and analysis of demand reduction options and technologies to establish estimates, define initiatives, and assess long-term potential; and
- detailed business planning, with savings and demand reduction targets derived from the conservation potential work and demand reduction investigation, in order to prepare business case analyses that set spending and investment levels sufficient to meet corporate and regulatory requirements.

A preliminary scope of the work for the 2011 DSM Plan recognized the need to first complete a study of the potential market for DSM resources. At the same time the Company also requires research and information about technologies and controls which may be suitable for "hard wired" connections between customer locations and the electric distribution system.

Development of the detailed 2011 DSM Plan will utilize existing resources wherever possible, in order to build on existing knowledge and minimize redundant work and costs. The detailed plan will draw upon existing FortisBC studies, such as:

- *Demand Side Management Five Year Business Plan 2006 – 2010,* October 31, 2005;
- *Efficiency Savings and Demand Reduction Potential*, September 15, 2005; and
- *Semi-Annual DSM Reports,* December 31, 2005-08 inclusive.

Also the plan development will draw upon existing BC Hydro work, such as:

- *BC Hydro Long Term Acquisition Plan (LTAP), 2008; and*
- *BC Hydro Conservation Potential Review (CPR), 2007.*

Finally the 2011 DSM Plan will review and utilize other studies, where applicable, for example:

- NRCan Survey of Household Energy Use (SHEU).

Reduce the Capacity Deficit

Notwithstanding the concern for future energy requirements, FortisBC is primarily capacity-constrained, not energy-constrained in the short term.

Figure 2: Energy Load / Resource Balance (GWh) – 2008 Forecast

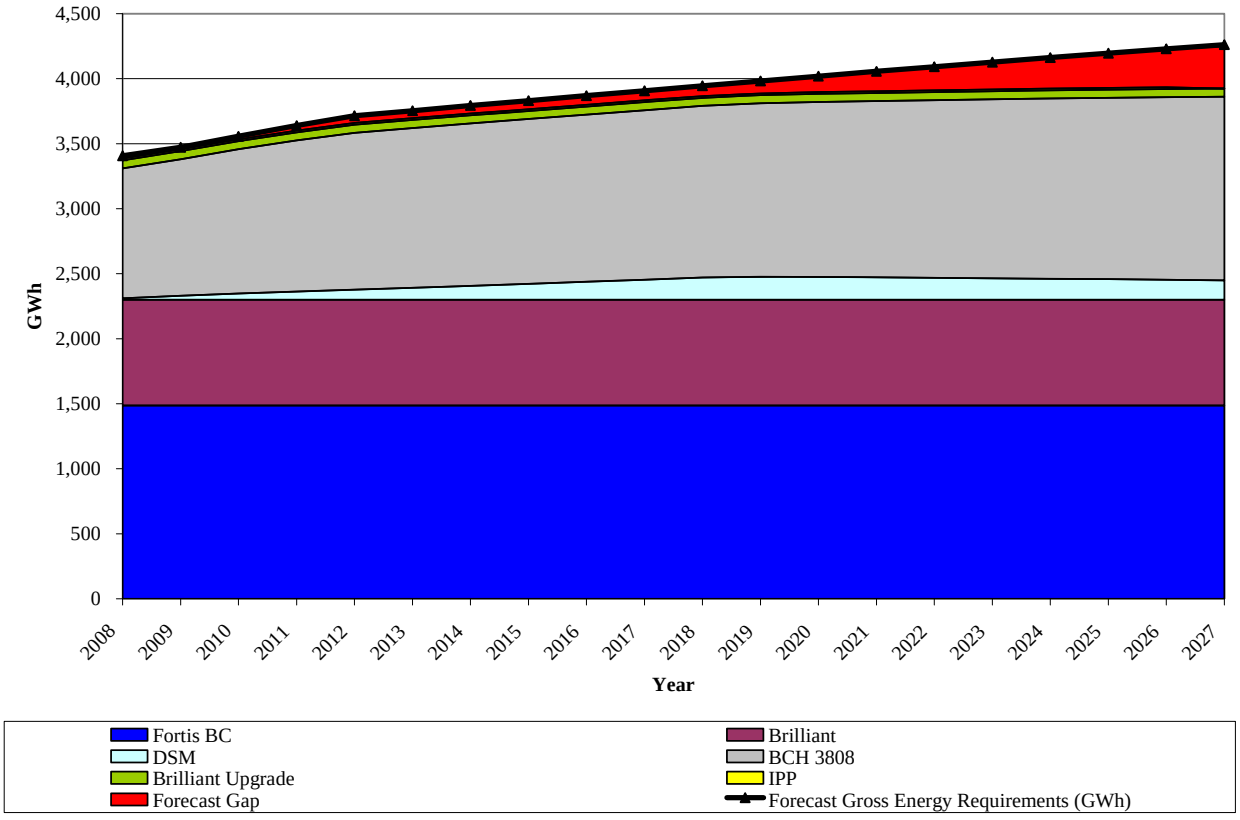
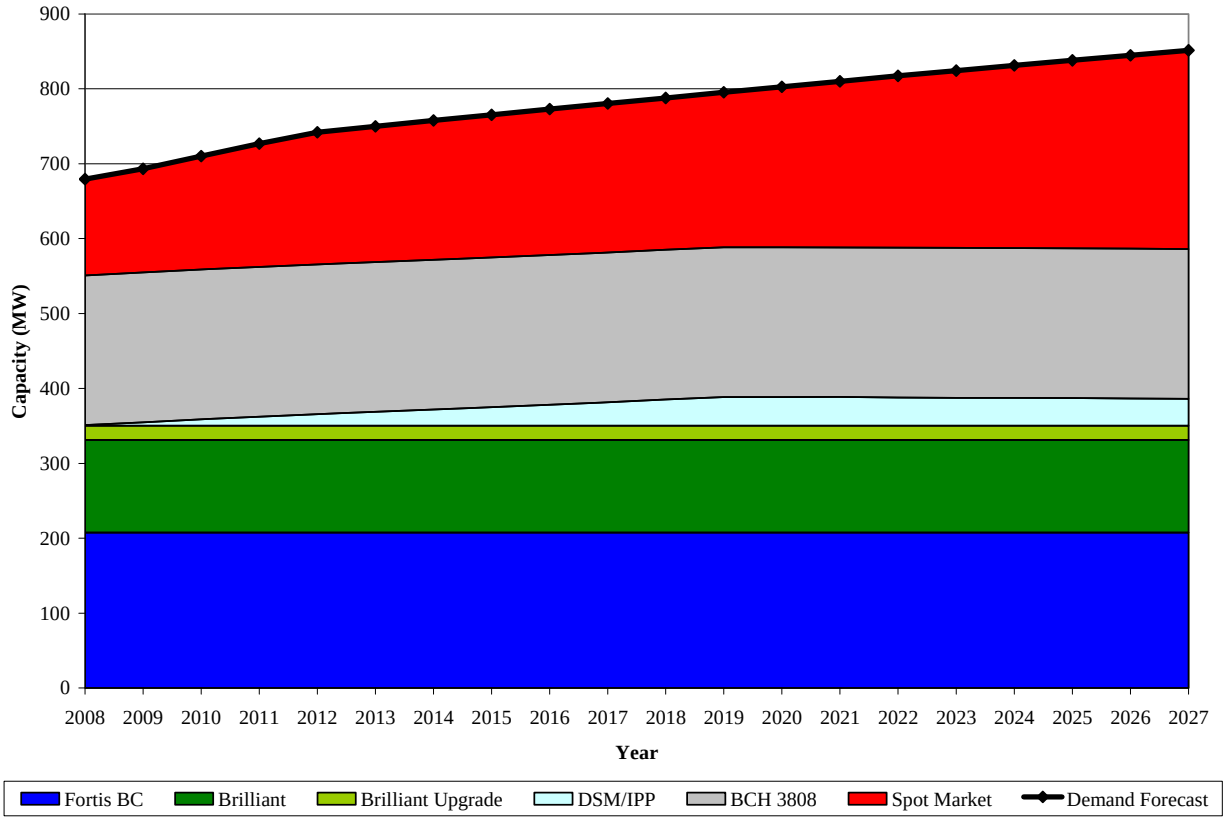


Figure 3: Capacity Load / Resource Balance (MW) – 2008 Forecast



The demand reduction expected from achieving the 50 percent energy savings target is shown in Figure 4.

Figure 4: Estimate of 2009-2020 Demand Reduction Associated with 50% Target

Customer Class	Demand Reduction (MW)
Residential	25.3
General Service	22.1
Industrial	2.2
Total Estimate	**49.6**

It is prudent for FortisBC to consider additional measures and services that have the potential to reduce customer demand during electric system peak periods. A recent study[4] by the Federal Energy Regulatory Commission ("FERC"), suggests that demand reduction capability represents between 3 percent and 7 percent of peak demand. The National Regulatory Research Institute further suggests[5] that the biggest demand reduction savings in pricing pilots were realized by customers with time-varying pricing and load control.

DSM programs promoting behavioural change through time-varying rates and awareness programs, possibly combined with load control, can provide additional demand reduction savings to those shown in Table 2. Given the load forecast for a 2020 peak demand of 810 MW (without any DSM), the additional demand reduction estimates range from 24 megawatts to 57 megawatts.

Further investigation is needed to plan for acquisition of demand reduction measures and to set reasonable reduction targets. It is recognized that the ability of FortisBC to address the capacity deficit will be limited until such time as an advanced metering or equivalent infrastructure is implemented. An advanced metering infrastructure provides three key elements required for effective demand reduction programs:

- the ability to measure energy use on an hourly or more frequent basis at each meter;
- the ability to cost-effectively implement time-varying electricity rate structures such as time-of-use rates; and
- the ability to cost-effectively implement load control on a wide scale.

Objective 10: The 2011 DSM Plan should identify the type of studies that should be undertaken that will allow development of effective demand response programs.

Update Monitoring and Evaluation Plans

FortisBC intends to periodically update the three-year Measurement and Evaluation (M&E) plan (Appendix A) to ensure existing programs are reviewed, on a priority basis, for process enhancements and energy savings impacts. In addition new programs will be required to have a draft M&E plan to ensure the baseline data is collected to enable subsequent M&E studies.

FortisBC plans to participate in a provincial task force on Measurement, Analysis and Reporting which seeks to harmonize public utility M&E practises. The task force has identified key variables in determining actual load impact including free riders and persistence. FortisBC intends to adopt common practises, once established, to ensure the appropriate level of due diligence in its DSM reporting.

[4] FERC Staff Report on Demand Response and Advanced Metering, David Kathan, FERC, October 10, 2006

[5] National Regulatory Research Institute, "Advanced Metering Infrastructure: What Regulators Need to Know About its Value to Residential Customers", Nancy Brockway, February 13, 2008.

Objective 11: The 2011 DSM Plan should include an updated monitoring and evaluation plan, if required, that will apply to all new and existing programs, and will be compliant with any provincial standards.

Promote New Technologies

The 2011 DSM Plan will identify innovative technologies that are applicable to major customer electrical end-uses. Such products and services are often more expensive than conventional alternatives, and little known other than to perhaps "early adopters". The 2011 DSM Plan will assist the purveyors of promising energy efficiency and demand reduction technologies to identify potential sites (both internal, company owned and external, customer owned) where the new technology could be tested. The Company may provide pre/post monitoring, or oversight of same, to confirm the energy savings estimates. Examples of such technologies might include:

- E-kube controls (commercial refrigeration);
- passive solar design; and
- customer owned generation (COG) technologies if eligible for net metering tariff[6].

Conservation rates will be addressed in forthcoming rate design filings, and are considered to be a driver that will encourage program participation. It should be noted that conservation rates designed to reduce demand, including time-of-use and critical peak pricing rates, are not cost-effective to implement on a large scale without an advanced metering infrastructure. The effects, if any, from future conservation rates will not be included in the 2011 DSM Plan.

The 2011 DSM Plan will not attempt to quantify the effects of efficiency-related Codes and Standards implemented by governments. If Codes and Standards have an impact by reducing load growth, the combined effect with enhanced PowerSense programs will result in energy savings in excess of the 50 percent target. However, for the purposes of the 2011 DSM Plan, the energy savings target will not be adjusted for the impact of Codes and Standards.

Objective 12: The 2011 DSM Plan should include new programs that promote technologies that are proven to be effective, but do not yet provide an economic payback for customers within 10 years.

[6] Less than 50 kW capacity, output not to exceed customer usage on an annual basis

Summary and Cost Estimates

The evolving nature of the external and internal environment in which FortisBC operates the PowerSense program makes the development of the long-term 2011 DSM Plan a necessary and prudent goal. The objectives set out in this document will provide a framework that will guide the development of the 2011 DSM Plan.

The preliminary cost estimate for the creation of the 2011 DSM Plan is shown in Table 3.

Table 3: Preliminary Cost Estimate for 2011 DSM Plan

Category	Forecast Expenditure
50 percent Target and Cost-Effective Demand-Side Management	$10,000
Coordinated Approach	$15,000
Awareness and Education	$30,000
Low Income Program	$25,000
Rental Accommodation Program	$20,000
Stakeholder Involvement	$25,000
Marginal Cost of Energy and Capacity	$10,000
Develop Conservation Potential for Energy and Capacity	$75,000
Reduce the Capacity Deficit	$10,000
Update Monitoring and Evaluation Plans	$5,000
Promote New Technologies	$10,000
Project Management	$20,000
Total	**$255,000**

For 2009, $100,000 has been approved for the 2011 DSM Plan as part of the 2009 Revenue Requirements application[7]. FortisBC intends to apply for the remaining funds for as part of the 2010 Revenue Requirements application, and will provide further details of the planned 2010 expenditures at that time.

[7] Exhibit B-1, 2009 Revenue Requirements Application, Tab 3, page 33, lines 6-13

In summary, the 2011 DSM Plan will address the following factors:

- Government policy and regulation, including the BC Energy Plan, UCA amendments and the DSM Regulation;
- Changing customer perceptions and expectations regarding DSM and customer-owned generation;
- The FortisBC capacity and energy deficit;
- The rising and uncertain cost of energy and capacity; and
- Technological change.

The 2011 DSM Plan will specify enhancements to the FortisBC PowerSense program that address the above factors and comply with the strategic objectives outlined in this report.

Planning Reserve Margin

Prepared
For

FORTISBC

By

Willis
ENERGY SERVICES LTD.

January 28, 2008

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Glossary

Automatic Generation Control or **AGC:** Equipment that automatically adjusts a Control Area's generation from a central location to maintain its interchange schedule plus Frequency Bias.

Balancing Authority: The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.

Balancing Authority Area: The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.

Canal Plant Agreement: The agreement, effective July 1, 2005 between British Columbia Hydro and Power Authority, FortisBC Inc., Teck Cominco Metals Ltd., Brilliant Power Corporation, Brilliant Expansion Power Corporation, Waneta Expansion Power Corporation. The agreement covers the operation of Hydro Power projects on the Kootenay and Pend d'Oreille rivers.

Canal Plant Entitlement Capacity: The electrical power capacity value in MWs that is available for specific plants that is included in the Canal Plant Agreement.

Contingency Reserve: An amount of Spinning and Non-spinning reserve, sufficient to reduce area control error (ACE) to the NERC DCS performance requirements within ten minutes, equal to the greater of:
(1) The loss of generating capacity due to forced outages of generation or transmission equipment that would result from the Most Severe Single Contingency (at least half of which must be spinning reserve); or
(2) The sum of five percent of the Control Area Demand served by hydro generation and seven percent of the Control Area Demand served by thermal generation (at least half of which must be spinning reserve). The combined unit ramp rate of each Control Area's on-line, unloaded generating capacity must be capable of responding to the Spinning Reserve requirement of that Control Area within ten minutes.

Control Area Demand: The control area demand is determined as the firm load inside the control area plus firm exports minus firm imports. This term is sometimes referred to as, "Load Responsibility".

Expected Load Forecast Annual Peak Demand: The highest Control Area Demand in MW forecast for a given year.
.
Non-spinning Reserve: Operating Reserve not connected to the system but capable of serving demand within a specified time, or interruptible load that can be removed from the system in a specified time.

Operating Reserve: Capability above firm system demand required to provide for regulation, load-forecasting error, equipment forced and scheduled outages and local area protection. Operating Reserve consists of Spinning Reserve and Nonspinning Reserve.

Planning Reserve: The generating capacity in excess of capacity to meet load for the purpose of supplying Spinning Reserve, Non-Spinning Reserve, Regulating Reserve, and for unexpected contingencies. A Planning Reserve is determined for a planning cycle of usually 10 to 20 years.

Regulating Reserve: Sufficient spinning reserve, immediately responsive to automatic generation control (AGC). The minimum amount required is the Regulating Reserve Requirement necessary to meet NERC's Control Performance Standard.

Resource Plan: A plan over a period usually 10 to 20 years for having sufficient power supply to satisfy expected power demand in a given control area.

Spinning Reserve: Unloaded generation, which is synchronized and ready to serve additional demand. It consists of Regulating reserve and Contingency reserve.

Thermal Generation: All non-hydro resources.

1. Introduction

FortisBC Inc. (FortisBC) is preparing a Resource Plan and part of this preparation involves a review of the Utility's Planning Reserve. This Report was prepared for FortisBC by Willis Energy Services Ltd. to assist in this review.

For the purpose of this report, Planning Reserve Margin means the margin between available power resources and customer load requirements. A utility's Resource Plan establishes this margin for a planning period (usually 10 to 20 years).

This report reviews FortisBC's Planning Reserve requirements by analyzing the following information:

- Requirements of regulatory bodies, particularly the Western Electricity Coordinating Council (WECC).
- Canal Plant Agreement, which stipulates the operating conditions of FortisBC's own resources.
- Power purchase agreement with BC Hydro.
- Transmission constraints, which are important when considering the import and export of power.
- The Transmission and Operating Reserve Services provided by the British Columbia Transmission Corporation (BCTC).
- An analysis of the power supply situation in the WECC Region.

Paul Willis prepared the report with assistance from Bruce Prior, former Manager of System Planning for BC Hydro and with information obtained in discussions with Stephen Tran, British Columbia Transmission Corporation, Tim Newton, Director Western Electricity Coordinating Council and Doug Robinson, BC Hydro generation.

2. Summary

The key conclusions of this study are:

- FortisBC is responsible for ensuring that the required Operating Reserve is in place at all times with respect to its total system load.
- Additional planning reserve amounts should be included in the Resource Plan. These amounts are additional to what was included in the 2005 Resource Plan. Exhibit 2.1 indicates the recommended amount of this additional reserve for milestone years over the planning period. Exhibit 12.2 in Section 12 indicates the recommended values over the 20-year planning period.
- It is suggested that the estimated cost of supplying the additional reserve be separately identified and that the initial estimate of this cost be the capital and fixed operating cost of a simple cycle combustion turbine (calculated to be $16.70 per MW per hour).

Exhibit 2.1 indicates the recommendations that an additional planning reserve of 38.33 MW for 2008, growing to 50.24 MW in 2027 be accounted for in the Resource Plan.

Exhibit 2.1 - Summary Recommended Planning Reserve (MW)

	2008	2013	2018	2023	2027
Expected Load Forecast Annual Peak Demand (MW)	679.53	749.86	787.96	824.41	851.41
High Load Forecast Annual Peak Demand - BCH 3808 Purchase (MW)	480.79	578.47	631.33	680.50	719.05
R Value from WECC Criteria (5% of High Load Forecast) (MW)	24.04	28.92	31.57	34.03	35.95
Largest Generating Unit (Brilliant unit)	37.33	37.33	37.33	37.33	37.33
Total Planning Reserve Requirement (MW)	**61.37**	**66.25**	**68.90**	**71.36**	**73.28**
Recommended Planning Reserve as Percent	9.0%	8.8%	8.7%	8.7%	8.6%
Reserve Planning Margin Already in Place					
Agreement under Canal Plant Agreement to share Spinning Reserve (MW)	23.04	23.04	23.04	23.04	23.04
Total in Place (MW)	**23.04**	**23.04**	**23.04**	**23.04**	**23.04**
Percent Reserve Planning Margin in Place	3.4%	3.1%	2.9%	2.8%	2.7%
Additional Reserve that Should be Included in Resource Plan (MW)	**38.33**	**43.21**	**45.85**	**48.31**	**50.24**
Additional Reserve Required as a Percent	5.6%	5.8%	5.8%	5.9%	5.9%

3. North American Electricity Reliability Council (NERC)

FortisBC is part of the western North America integrated electric system and NERC's responsibility is to develop and enforce reliability standards with respect to utilities that are part of integrated systems in North America. Establishing a Planning Reserve is a reliability item and NERC's standards in this respect should be followed.

The most stringent and relevant NERC reliability standards are those standards developed by regional coordinating councils that are approved by NERC. In the case of FortisBC, the regional coordinating body is the Western Electricity Coordinating Council (WECC). With respect to reserve requirements, the relevant WECC standard that has been approved by NERC is:

- WECC Standard BAL-STD-002-0 – Operating Reserves.

This NERC approved standard indicates the Operating Reserve requirements that are required to be in place at all times. The specific values are discussed in the following two sections. NERC and in turn WECC have authority under the Federal Energy Regulatory Commission (FERC) and the U.S. Federal Power Act to levy financial sanctions for non-compliance to these requirements. For Canadian entities, the British Columbia Utilities Commission has approved WECC's authority and governance with respect to the Balancing Authority in British Columbia (British Columbia Transmission Corporation (BCTC).

4. Operating Reserve versus Planning Reserve

"The industry commonly refers to two kinds of reserve margins, namely, operating reserve margin for day to day operations, and planning reserve margin for short or long term planning purposes. A planning reserve margin is generally higher than an operating reserve margin since it must account for all of the uncertainties. A planning reserve margin includes the margin for an operating reserve margin plus an additional margin for planning purposes."[1]

The Western Electricity Coordinating Council (WECC) has defined the following operating or contingency reserve requirement:

"This Contingency Reserve shall be at least the greater of: (1) The loss of generating capacity due to forced outages of generation or transmission equipment that would result from the most severe single contingency (at least half of which must be spinning reserve); or (2) The sum of five percent of the load responsibility served by hydro generation and seven percent of the load responsibility served by thermal generation (at least half of which must be spinning reserve)."

The WECC does not currently have a Planning Reserve requirement. However, a Power Supply Assessment Policy[2] defines a requirement to "project whether enough resources exist, at any price, to meet load and possible reserves while considering the transmission transfer capabilities of major paths." WECC's Planning Coordinating Committee has also recently recommended that the WECC Power Supply Design Criteria[3] be used as a guideline on an interim basis.

5. WECC Power Supply Design Criteria

It is recommended that FortisBC use WECC's Power Supply Design Criteria as the basis for determining their Planning Reserve. Sections 5.1, 5.2 and 5.3 below are taken directly from this WECC Document. Section 5.4 is Willis conclusions as to how these Criteria can be applied to determining FortisBC's Planning Reserve.

5.1. Purpose of Criteria

The criteria in this document are intended to provide, for the guidance of members, recommended minimum levels of installed and planned generation for systems and areas within the WECC in order to permit evaluation, upon a common basis, of the relative reliability of the interconnected bulk power systems. The criteria do not purport to establish any measure of industry design standards as to member systems, nor are they created for such purpose, it being recognized that the systems of members, pools, or other groups of Council members, may be properly and adequately designed to different criteria.

It is recognized that it is impossible to provide 100% reliability of power supply. It is anticipated that each member will, insofar as practical, protect its customers against loss of service. With the development of the complex interconnected systems, it is likely that the design and performance of one system will be reflected in varying degrees on other systems. Subject to the foregoing, it is the purpose of the criteria to provide:

[1] WECC 2006 Power Supply Assessment, Attachment 2, Section D Reserve Margin, page 60.
[2] WECC 2006 Power Supply Assessment, Attachment 3.
[3] WECC 2006 Power Supply Assessment, Attachment 4.

1. Recommended minimum standards and a uniform method for assessing the adequacy of installed and planned generation within the WECC for the purposes of reporting to the Council, and to outside agencies.

2. A means for evaluating the possible effect of one system or area on other systems or areas.

The WECC members will assess resource adequacy in accordance with the *North American Electric Reliability Council (NERC)* Planning Policies and Principles or the *WECC Power Supply Design Criteria*, whichever is more specific or stringent.

5.2. Criteria for System Design

The criteria are based on the principle that for the more common contingency outages there should be no loss of load in a system or area or adverse effect on neighboring systems or areas. The criteria recognize the necessity for load shedding for those outage contingencies that are credible but of such low probability that it is not feasible to protect the systems against loss of load.

Power supply criteria may be defined and measured in terms of generating reserve margins, ability to withstand contingency outages, or minimum reliability index values derived from probabilistic computations based on capacity.

Each member of the Council, and each Pool or other group of Council members, may utilize criteria, which differ from the criteria presented in this document. Such differences may be based upon the geography of the area, type of load being served, system configuration, customer expectations based upon past performance, or other reasons considered appropriate by such member, Pool or group, as long as the minimum requirements of the WECC criteria are met.

It is recommended that the following criteria be utilized in the design of each member system or area.

1. Each member system or area should provide sufficient generating capacity to serve its load and meet its obligation to others without imposing an undue degradation of reliability on any other system or area.

2. If two or more systems form a group or responsible area for the specified purpose of applying WECC Power Supply Criteria, they should demonstrate that any inter- or intra-area generating capacity support levels utilized are achievable and that sufficient transmission capacity is available to allow delivery at these levels of generating capacity support.

Assessments of future resource adequacy should generally include the following:

- Electricity demand and energy forecasts, including uncertainties
- Existing and planned demand-side management programs (DSM) including in-service dates and life-cycle
- Demand-side management program characteristics should include the following:

  - Consistent ratings (demand and energy), including seasonal variations
  - Effect on annual system load shape
  - Availability, effectiveness, and diversity of DSM programs
  - Contractual arrangements
  - Expected program duration
  - Aggregate effects (demand and energy) of multiple DSM programs
- Existing and planned supply-side resources including in-service dates and life-cycle
- Supply-side resource characteristics should include the following:
  - Consistent generator unit ratings, including seasonal variations
  - Availability of utility and independent power producer generator units
  - Dependability of and contractual obligations, including assignment of system losses, for capacity and energy purchases and sales
  - Abnormal or adverse water conditions for hydro and thermal generator units
  - "Net" capacity after deduction of electrical supply for station or auxiliary services
  - Fuel availability, deliverability, and diversity
  - Retirement of resources
- Delays in resource in-service dates
- Availability and performance characteristics of all resources
- Resource type; include energy profile and any environmental or regulatory restrictions
- Availability of emergency assistance from neighboring systems
- Resources not under a system's control should be addressed in the planning process as to availability, capacity, emergency assistance, scheduling, and deliverability
- Purchasers, transmitters, and sellers of electricity should coordinate and agree with each other on the characteristics and level of dependability of their electricity transactions for reliability assessment purposes, including such factors as:
  - Contractual commitments
  - Duration of the transaction
  - Dependability of the transaction
  - Availability of dedicated generator units
  - Availability of transmission capacity
  - Effect of the transaction on deliverability of emergency assistance

Technical studies should be performed to periodically evaluate these criteria and that the criteria be periodically reviewed and revised as experience indicates.

5.3. Recommended Minimum Performance Levels

The WECC's recommended level of installed and planned generating supply reserve is presented in the Recommended Minimum Performance Table, Exhibit 5.1. This table defines recommended minimum power supply reserve levels for reporting systems or areas in the WECC.

Because reliability reserve levels vary between WECC member systems, three alternative recommended minimum criteria are provided. In planning and installing resources, each member should endeavor to maintain a balanced relationship among resource type, size, capacity, and location. It is recommended that Member Systems with a significant percentage of independent power producer owned generation utilize probability methods for reserve planning and reporting. It is further recommended that all systems ultimately report installed and planned reserve levels using probability methods.

Exhibit 5.1 - Recommended Minimum Performance Table

	Criteria	Minimum Design Performance
1.	Monthly Reserve Capacity After Deducting Scheduled Maintenance (MW)	Greater of R, or the largest Risk plus 5 percent of Load Responsibility
2.	Monthly Reserve Capacity After Deducting Scheduled Maintenance	2 largest Risks
3.	*Annual reliability criterion based on probability of loss of load, either	
	a. Frequency of loss of load or,	one day in ten years
	b. probability of meeting all loads in a year	0.90

Definitions

$$R = \frac{(.05\ H + .15\ T)}{H + T} \times L$$

H = Monthly hydro capability after deducting scheduled maintenance.

T = Monthly non-hydro generating capability after deducting scheduled maintenance.

L = Load Responsibility: System or area monthly firm peak load demand plus those firm sales minus those firm purchases for which reserve capacity must be provided by the supplier.

Reserve Capacity After Deducting Scheduled Maintenance = H + T – L

Risk: Capacity reduction caused by outage of a generator (including independent power producer owned) or transmission line.

* Independent power producer owned generation shall be included when assessing adequacy of power supply using this Criterion.

5.4. WECC Criteria Applied to FortisBC

WECC's Recommended Minimum Performance Table (Exhibit 5.1) above provides three different criteria for a utility to use. FortisBC have not conducted a Loss of Load Probability study with respect to their own generation and the Brilliant Project. Accordingly, Criteria 3 cannot be used.

Using Criteria 1, the following is a calculation for determining the FortisBC Reserve level.

$$R = \frac{(.05H + .15T)}{H + T} \times L$$

Where:

H = FortisBC, Brilliant Resources = 350.19 MW
T = Zero, no thermal resources on FortisBC system
L = 480.79 MW, High Peak Load Forecast for 2008 – BCH 3808 Purchases

R = 24.04 MW

Criteria 1 refers to the Greater of R (calculated above), or the largest Risk plus 5 percent of Load Responsibility. This largest Risk item is estimated to be 37.33 MW. It is based on the largest generation unit on FortisBC's system, which is a Brilliant unit. For more explanation see Section 7 below.

Using Criteria 1, the recommended reserve level is the greater of R, or the largest Risk plus 5 percent of Load Responsibility. The Load Responsibility is 480.79 MW and five percent of this value is 24.04 MW. The largest Risk plus 5 percent of Load Responsibility is greater than R. Therefore, based on 1, the recommended Reserve Level for 2008 is 37.33 MW + 24.04 MW = 61.37 MW.

Criteria 2 would involve considering the two largest risks, which would be two Brilliant units or 2 X 37.33 = 74.66 MW. It is recommended that Criteria 1 be used instead of Criteria 2. The reason being that, although it is not included as part of FortisBC's CPA entitlement, there is a high probability that capacity would be available from the Brilliant Expansion project at times of infrequent and unexpected outages of major units within the FortisBC system. The Brilliant Expansion project is a low load factor project and as such for a significant percentage of the time capacity would be available for sale to FortisBC during periods of extreme emergency. Accordingly, the consideration of one Brilliant unit as the largest risk element is appropriate.

5.5. Planning Reserve and Supply Portfolio

It is important to note that the generation supply portfolio that is selected to suit a 20-year planning horizon affects the Planning Reserve amount. For example, a generation portfolio which included thermal generation should have a higher Planning Reserve than a portfolio that involved meeting additional capacity needs through a firm capacity energy purchase from BC Hydro. This is because in the WECC criteria a higher Planning

Reserve is specified when thermal generation is employed (see Exhibit 5.1 above) and in a firm purchase arrangement the supplier such as BC Hydro would be responsible for the Planning Reserve margin for the amount purchased.

6. WECC 2006 Power Supply Assessment

In determining the Planning Reserve level that a particular utility requires it is important to consider the estimated Planning Reserve that will likely be in place in the power supply region that they are part of. If it appears that there is going to be ample Planning Reserve in adjoining jurisdictions, a lower Planning Reserve level can be justified. On the other hand if it appears that the Planning Reserve is going to be reduced and potentially approach critical levels in other jurisdictions than a higher Planning Reserve is justified.

Accordingly, the result of the Western Electricity Coordinating Council's Power Supply Assessment (PSA) is an important background to a review of an appropriate Planning Reserve for FortisBC's current Resource Plan.

The Exhibit below is a synopsis of the results showing the first year deficiency for each sub-region within WECC according to different seasonal and weather scenarios. A deficit condition is an indication that a sub-region was unable to meet its load requirements given the parameters for that scenario. The deficit amount ( ) is the net shortage that the model is showing for the sub-region. The "year of first deficit" could also be considered as the year that additional facilities (besides those already included) must be in-service to avoid margin deficiencies.

Exhibit 6.1 - Year of First Deficit and Deficit Amount (MW)

Sub-Region	Scenario						
	1	2	3	4	5	6	7
	Summer Base	Winter Base	Summer Hot	Winter Cold	Summer 15%	Summer Base+	Winter Base+
Canada	2013 (306)	2008 (319)	2013 (306)	2007 (104)	2011 (198)	2013 (303)	2008 (316)
Northwest			2015 (129)		2013 (11)		
Rockies	2009 (795)		2008 (220)		2008 (823)	2008 (735)	
Desert Southwest	2009 (118)		2009 (205)		2008 (21)	2008 (17)	
No. California	2013 (486)		2011 (38)		2011 (441)	2013 (486)	
So. California	2010 (1120)	2011 (151)	2009 (1327)	2010 (76)	2008 (320)	2010 (444)	2011 (65)

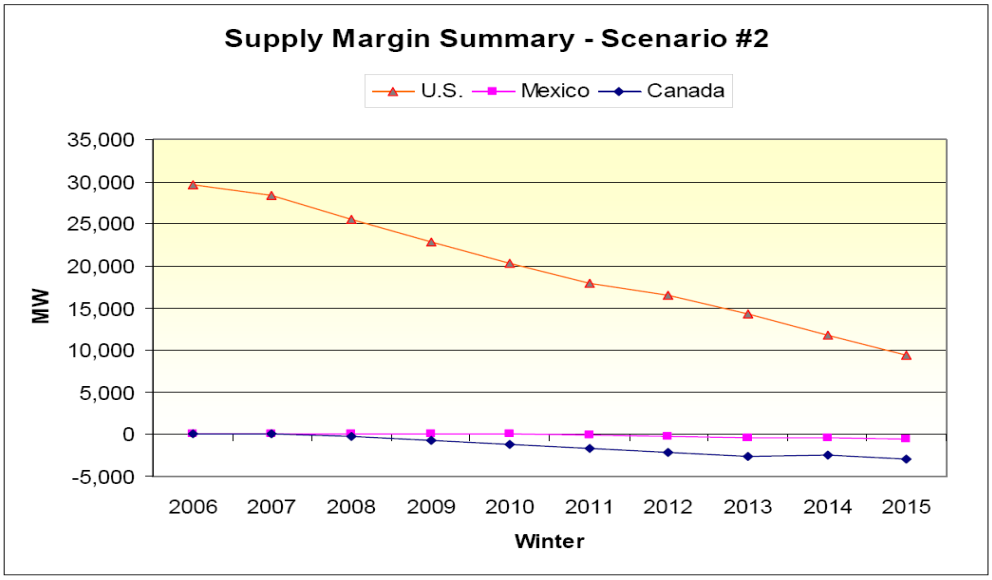
Blank indicates that no deficit occurred; Base+ indicates that no completion limit was applied to planned resource additions/retirements.

Note that Canada is forecast to have an inadequate margin in the winter of 2008. In this context BC Hydro is acquiring curtailable load contracts with their large industrial customers for the winter of 2008 and beyond.

The exhibit below indicates the potential growing deficit in Canada. This PSA study recognized that BC Hydro has issued Requests for Power (RFP) to address this situation. However, with

respect to BC Hydro's latest RFP, there is considerable uncertainty as to how many of the contracts awarded will result in completed projects. BC Hydro in a submission to the BCUC indicated that they are expecting a 30 percent attrition rate[4].

Exhibit 6.2 - Supply Margin Summary showing Winter Constraints



In conclusion, it appears that the Planning Reserve in the region surrounding FortisBC's jurisdiction is being reduced. Accordingly, the probability that BC Hydro or other utilities will be able to assist FortisBC in a crisis situation is reduced.

[4] Report on the Call for Tenders (CFT) Process – Submitted by BC Hydro to the BCUC, August 31, 2006

7. Reliability of FortisBC Hydro Generation

FortisBC owns four hydroelectric generating plants on the Kootenay River with an installed capacity of 235 MW. The following exhibit lists the four plants.

Exhibit 7.1 - FortisBC Owned Regulated Generation Facilities[5]

Plant	Location	Year Installed	Completion Year of Refurbishment	Entitlement Capacity (MW)	Number of Units	2006 Net Entitlement (MWh)
No. 1	Lower Bonnington	1924	1998 (1), 2006 (1)	66	3	298,799
No. 2	Upper Bonnington	1907	2004 (2)	66	6	465,233
No. 3	South Slocan	1928	2001 (3)	54	3	414,302
No. 4	Corra Linn	1932	2000 (4)	49	3	311,028
Totals				**235**	**15**	**1,489,362**

Notes:
(1) In 1998, Unit 2 was refurbished. In 2006, Unit 1 was refurbished.
(2) In 2004, Unit 5 and Unit 6 were refurbished.
(3) In 2001, Unit 2 was refurbished.
(4) In 2000, Unit 3 was refurbished.

In addition to their own plants FortisBC is responsible for the operation of the Brilliant power project and accordingly its maintenance outages. The Brilliant project has a capacity of four units at 37.33 MW each for a total plant generation of 149.30 MW.

The reliability of these plants and the probability of forced outage are key considerations in determining an adequate Reserve Margin. FortisBC has not conducted a Loss of Load Probability Study, which would involve looking at the maintenance and outage records of these plants over a long period. In the absence of this type of study, an approach for determining loss of generation risk is to assume that at anytime the largest generating unit could be forced out of service. The largest generating unit serving the FortisBC load is one of the Brilliant units at a capacity of 37.33 MW.

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8. Canal Plant Agreement[6]

The Canal Plant Agreement is an agreement for the coordinated operation of a number of generating resources on the Kootenay and Duncan Rivers. This Agreement includes power projects owned by FortisBC and other projects from which FortisBC purchases power on a long-term contract basis. In 2006, FortisBC obtained 46.0 % of its capacity needs and 71.3 % of its energy needs from plants operated and controlled within the terms of this Agreement.

[5] Exhibit 7.1 was extracted from FortisBC Annual Information For the Year Ended December 31, 2006 issued on March 8, 2007.
[6] Canal Plant Agreement, effective July 1, 2005, Reference 1.

The Agreement defines what capacity and energy is available from the projects supplying FortisBC and under what conditions including consideration for Operating Reserve requirements.

With respect to the Power Projects covered by this Agreement, Exhibit 8.1 indicates the power capacity that is available on a month-by-month basis to serve FortisBC load from each of the Plants. The maintenance allowance values were determined by calculating the average maintenance allotments for the five years from 2002 to 2006.

FortisBC's peak load is forecast for January each year, accordingly from a Resource Planning modeling perspective; the capacity available in January is used to determine the capacity available. From Exhibit 8.1, the gross capacity available from Canal Plant Agreement plants is 368.70 MW. Subtracting a maintenance allowance of 2.20 MW (0.6% of Gross) and operating margin of 16.30 MW (4.5% of Gross), the net capacity available is 350.20 MW (95% of Gross).

The Operating Margin is based on 2.45% for Spinning Reserve and 2.0% for regulation. The Spinning Reserve is a Western Electricity Coordinating Council (WECC) requirement and the 2.0% is the Regulation and Frequency Response (RFR) Service requirement from the British Columbia Transmission Corporation[7]. This RFR requirement is a standard requirement for balancing load on a system and in BCTC's case is an approved BCUC tariff.

WECC also requires 2.5% of Non-Spinning Reserve. Willis asked FortisBC as to how this 2.5% non-spinning reserve was supplied and FortisBC indicated that the allowance for the non-spinning reserve is not presently included within their long-term plan although the requirement is satisfied on a day-by-day basis.

[7] British Columbia Transmission Corporation Open Access Transmission Service Tariff, Schedule 05.

Exhibit 8.1 - Capacity of Canal Plant Agreement Power Projects That Supply FortisBC Load

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
FortisBC Plants*												
Capacity Entitlement (MW)	219.60	215.80	208.80	205.10	195.50	186.30	196.80	212.10	216.10	217.20	223.50	223.00
Maintenance Allowance (MW)	(2.20)	(5.80)	(3.60)	(14.20)	(3.00)	(0.40)	(0.40)	(0.40)	(17.20)	(9.32)	(9.48)	(10.20)
Spinning Reserve & Regulation (MW)	(9.67)	(9.35)	(9.13)	(8.50)	(8.57)	(8.27)	(8.74)	(9.42)	(8.85)	(9.25)	(9.52)	(9.47)
FortisBC Net Capacity Entitlement (MW)	207.73	200.66	196.07	182.40	183.93	177.63	187.66	202.28	190.05	198.63	204.50	203.33
Columbia Power Corporation (Brilliant)												
Capacity Entitlement (MW)	129.30	129.40	129.40	123.60	111.80	105.30	111.90	121.50	125.40	125.50	129.40	129.30
Maintenance Allowance (MW)	0.00	(22.24)	(29.70)	(0.80)	0.00	0.00	0.00	0.00	0.00	(7.20)	0.00	0.00
Spinning Reserve & Regulation (MW)	(5.75)	(4.77)	(4.44)	(5.46)	(4.98)	(4.69)	(4.98)	(5.41)	(5.58)	(5.26)	(5.76)	(5.75)
Brilliant Net Capacity Entitlement (MW)	123.55	102.39	95.26	117.34	106.82	100.61	106.92	116.09	119.82	113.04	123.64	123.55
Columbia Power Corporation Brilliant Unit Upgrades												
Capacity Entitlement (MW)	19.80	19.80	19.90	20.00	19.80	19.50	19.70	20.10	19.60	19.70	20.10	20.00
Maintenance Allowance (MW)	-	-	-	-	-	-	-	-	-	-	-	-
Spinning Reserve & Regulation (MW)	(0.88)	(0.88)	(0.89)	(0.89)	(0.88)	(0.87)	(0.88)	(0.89)	(0.87)	(0.88)	(0.89)	(0.89)
Brilliant Upgrade Net Capacity Entitlement (MW)	18.92	18.92	19.01	19.11	18.92	18.63	18.82	19.21	18.73	18.82	19.21	19.11

* FortisBC Plants include Lower Bonnington, Upper Bonnington, South Slocan, Corra Linn, and South Slocan.

9. Reliability of FortisBC Transmission System

The purpose of this report is to assess the margin that is required between available power resources and customer load requirements. FortisBC does operate an integrated generation, transmission and distribution system and therefore although availability of power sources is the main focus, the reliability and contingency reserve planning with respect to the FortisBC transmission system is relevant.

It is relevant for the following reasons:

1. The reliability of power from FortisBC's own generation system reaching the load centers depends on the reliability of the transmission system.

2. FortisBC does not have sufficient generation within its own region and requires power imports; accordingly, the reliability of this import power reaching the FortisBC load depends on the reliability of the transmission system.

FortisBC's 2005-2024 System Development Plan (SDP) indicated that a number of impact studies were carried out to evaluate the performance of the transmission system following various single (N-1) and selective double N-1-1 (one element out of service for maintenance, second element fails) or N-2 (double unrelated) contingency outages. The Plan did not identify that having additional generation reserve would assist in addressing any of these contingency events.

The SDP also indicated that The BC Hydro interconnections at Vernon, Princeton and Vaseux Lake Terminal (2005/06) play a very important role in transporting power into the Okanagan region from the generating plants in the Kootenay region. However, the Plan did not indicate the necessity for any additional generation resource to improve the reliability of these interconnections.

In reviewing the SDP it was concluded that FortisBC's transmission planning activity, at this time, did not include adding power generation capacity reserve to address transmission contingency reserve requirements.

10. Reserve Requirements and Power Imports

10.1. Power Purchase Agreement with BC Hydro

This Power Purchase Agreement is also a regulated BCH tariff (rate schedule 3808). Under the Agreement, FortisBC has the right to purchase up to 200 MW of capacity and associated energy. Per discussions with BCTC and BCH, FortisBC does not have any Operating Reserve responsibilities with respect to this 200 MW of capacity. The spinning, non-spinning reserve and regulation requirements for this power are supplied by BC Hydro as part of the power supply.

10.2. Market Power Purchases

FortisBC in order to supply its current peak load requirements purchases power from the wholesale electricity market. Such purchases, except for purchases from Teck Cominco Metals Ltd. or the Columbia Power Corporation will involve transmission across BCTC transmission lines or BPA transmission lines. For such purchases FortisBC must arrange for Operating Reserve requirements. These requirements can be provided by:

1. FortisBC allotting some of its own generating capacity to supply this reserve;
2. Purchasing the reserve requirement as part of the power purchase, in which case the power seller provides the operating reserve.
3. Purchasing the reserve from BCTC,

Since FortisBC uses all of its own generating capacity to supply its demand requirements, it must currently rely on 2/ and 3/. The current cost of purchasing Operating Reserve from BCTC is $ 6.25 per MW per hour.

In order to supply Operating Reserve, spare capacity must be available. BCTC currently are able to provide this service because they are able to purchase the spare capacity from BC Hydro. The current cost of them doing so is relatively low because it is based on the cost of BC Hydro's existing hydro generating facilities, all of which have a low cost of generation. It is important to note that the existing BCTC tariff under which they sell operating reserve is due to be terminated in December 2009. After that date the cost of Operating Reserve will be more market based.

The future cost of Operating Reserve will most likely be tied to the cost of marginal capacity. BC Hydro in their 2007 Conservation Potential Review[8] study indicated that the cost of marginal capacity for the Southern Interior is $58,700 per MW per year. This cost was based on the cost of adding a generating unit to the BC Hydro Mica Power Project (Mica 5). This unit would provide mostly capacity and very little energy. Another method for determining the cost of marginal capacity is to base it on the cost[9] of a simple cycle gas turbine plant; the capital of such a plant is $ 1,090,000 per MW and the fixed operating cost is $35,230 per MW per year, which combined translates to $16.70 per MW per hour.

The exhibit below compares these different marginal cost estimates with the current BCTC cost on the same basis.

Exhibit 10.1 - Cost of Capacity versus Cost of Operating Reserve

Current BCTC Costs, $/MW/hr	Simple Cycle Combustion Turbine Plant, $/MW/hr	BCH CPR 2007 Costs, $/MW/hr
6.25	16.70	6.70

It is important in considering the cost of capacity to consider the gap between demand and supply that is developing in British Columbia and the whole Western Electricity Coordinating Council

[8] BC Hydro's 2007 Conservation Potential Review – November 2007, note to External Review Panel dated May 29, 2007
[9] An estimate for a simple cycle gas turbine plant is provided in Appendix 7, BC Hydro's IEP, reference 4

region. Refer to Section 6 in this report: WECC 2006 Power Supply Assessment. The cost from BCH's CPR information is considered at the low-end of the estimate; BC Hydro in analyzing conservation potential opportunities recommended that a value of $19.40 per MW per hour be used. The margin between 6.70 and 19.40 was to account for a number of factors including:

- The cost of obtaining capacity for different regions is different. The $19.40 is based on the most expensive region from BC Hydro's perspective (Vancouver Island).
- Margin to ensure that all reasonable conservation measures would be considered.

It is suggested that the value of $16.70 per MW per hour based on the cost of a Simple Cycle Combustion Turbine Plant (SCCT) be used as the cost of capacity for Planning Purposes. An SCCT can be built within one-year in an urgent supply situation as part of a sub-station complex. Its costs are well defined with a large number of suppliers readily available. Other capacity sources may be available such as additional units at existing hydro-generating facilities at lower prices, however with the pending shortfall in capacity within the region, it is suggested that the low-cost sources will not represent the future marginal cost.

11. BC Hydro Capacity Planning Reserve

In determining FortisBC's Planning Reserve, the Planning Reserve that BC Hydro has in place is a good reference point. In a recent report to the BCUC, BC Hydro indicated their Planning Reserve[10] to be as follows:

Dependable Capacity	11,567 MW
Planning Reserves	1,637 MW
Percent Reserve Margin	14.2%

12. Conclusions and Recommendations

The following was concluded:

1. FortisBC is responsible for ensuring that an adequate Operating Reserve is in place at all times to cover its total system load. However, the required spinning and non-spinning reserve amounts do not have to be FortisBC's own resources.

2. The Spinning Reserve requirement for FortisBC's plants and for the power purchases from the Brilliant project is included in the Canal Plant Entitlement Capacity values.

3. The Spinning and Non-spinning Reserve with respect to the "3808" purchases from BC Hydro are included in the purchases from BC Hydro and no other Spinning or Non-spinning Reserve is required with respect to this purchase.

[10] BC Hydro/Alcan 2007 Electricity Purchase Agreement Report, Appendix I, Calculation of Capacity Planning Reserves.

4. The Spinning and Non-spinning Reserve values with respect to Spot Market purchases must be purchased from the seller or sellers of the Spot Market power or purchased from BCTC or supplied by FortisBC's own generation.

5. The Reserve Capacity Margin for the WECC region will decrease over the next 10 to 20 years (exhibit 6.4, Section 6). Accordingly, FortisBC in determining a Planning Reserve should take this development into consideration and provide additional Planning Reserve within its own Resource Plan.

6. The cost of supplying additional Planning Reserve beyond the Operating Reserve that is already in place is estimated to be $16.70 per MW per hour or $146,292 per MW per year and for the recommended additional Reserve amount the estimated cost for 2008 would be $7,860,269.

7. Curtailable Load should not be counted as Planning Reserve unless curtailable load contracts are in place.

Exhibit 12.1 below indicates the Recommended Planning Reserve for milestone years 2008, 2013, 2018, 2023 and 2027.

Exhibit 12.1 - Summary Recommended Planning Reserve (MW)

	2008	2013	2018	2023	2027
Expected Load Forecast Annual Peak Demand (MW)	679.53	749.86	787.96	824.41	851.41
High Load Forecast Annual Peak Demand - BCH 3808 Purchase (MW)	480.79	578.47	631.33	680.50	719.05
R Value from WECC Criteria (5% of High Load Forecast) (MW)	24.04	28.92	31.57	34.03	35.95
Largest Generating Unit (Brilliant unit)	37.33	37.33	37.33	37.33	37.33
Total Planning Reserve Requirement (MW)	**61.37**	**66.25**	**68.90**	**71.36**	**73.28**
Recommended Planning Reserve as Percent	9.0%	8.8%	8.7%	8.7%	8.6%
Reserve Planning Margin Already in Place					
Agreement under Canal Plant Agreement to share Spinning Reserve (MW)	23.04	23.04	23.04	23.04	23.04
Total in Place (MW)	**23.04**	**23.04**	**23.04**	**23.04**	**23.04**
Percent Reserve Planning Margin in Place	3.4%	3.1%	2.9%	2.8%	2.7%
Additional Reserve that Should be Included in Resource Plan (MW)	**38.33**	**43.21**	**45.85**	**48.31**	**50.24**
Additional Reserve Required as a Percent	5.6%	5.8%	5.8%	5.9%	5.9%

Exhibit 12.2 on the following page indicates the Planning Reserve requirement for all the years throughout the Planning Period.

Exhibit 12.2 - Recommended Planning Reserve (MW)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Expected Load Forecast Annual Peak Demand (MW)	679.53	693.24	710.26	726.69	741.89	749.86	757.66	765.31	772.88	780.48	787.96	795.45	802.87	810.18	817.38	824.41	831.34	838.19	844.89	851.41
High Load Forecast Annual Peak Demand (MW)	680.79	697.28	719.99	742.86	764.86	778.47	792.23	800.74	809.81	820.25	831.33	843.57	851.48	860.60	870.09	880.50	892.04	900.48	909.76	919.05
High Load Forecast Annual Peak Demand - BCH 3808 Purchase (MW)	480.79	497.28	519.99	542.86	564.86	578.47	592.23	600.74	609.81	620.25	631.33	643.57	651.48	660.60	670.09	680.50	692.04	700.48	709.76	719.05
R Value from WECC Criteria (5% of High Load Forecast)	24.04	24.86	26.00	27.14	28.24	28.92	29.61	30.04	30.49	31.01	31.57	32.18	32.57	33.03	33.50	34.03	34.60	35.02	35.49	35.95
Largest Generating Unit (Brilliant unit)	37.33	37.33	37.33	37.33	37.33	37.33	37.33	37.33	37.33	37.33	37.33	37.33	37.33	37.33	37.33	37.33	37.33	37.33	37.33	37.33
Total Planning Reserve Requirement (MW)	**61.37**	**62.19**	**63.33**	**64.47**	**65.57**	**66.25**	**66.94**	**67.37**	**67.82**	**68.34**	**68.90**	**69.51**	**69.90**	**70.36**	**70.83**	**71.36**	**71.93**	**72.35**	**72.82**	**73.28**
Resources																				
Annual Average FortisBC Entitlement (MW)	209.98	209.98	209.98	209.98	209.98	209.98	209.98	209.98	209.98	209.98	209.98	209.98	209.98	209.98	209.98	209.98	209.98	209.98	209.98	209.98
Annual Average Brilliant (MW)	122.65	122.65	122.65	122.65	122.65	122.65	122.65	122.65	122.65	122.65	122.65	122.65	122.65	122.65	122.65	122.65	122.65	122.65	122.65	122.65
Annual Average Brilliant Upgrade (MW)	19.83	19.83	19.83	19.83	19.83	19.83	19.83	19.83	19.83	19.83	19.83	19.83	19.83	19.83	19.83	19.83	19.83	19.83	19.83	19.83
Annual Average Brilliant Expansion (MW)	93.33	93.33	93.33	93.33	93.33	93.33	93.33	93.33	93.33	93.33	93.33	93.33	93.33	93.33	93.33	93.33	93.33	93.33	93.33	93.33
Annual Average Waneta (MW)	475.97	475.97	475.97	475.97	475.97	475.97	475.97	475.97	475.97	475.97	475.97	475.97	475.97	475.97	475.97	475.97	475.97	475.97	475.97	475.97
Total Resources (MW)	**921.77**	**921.77**	**921.77**	**921.77**	**921.77**	**921.77**	**921.77**	**921.77**	**921.77**	**921.77**	**921.77**	**921.77**	**921.77**	**921.77**	**921.77**	**921.77**	**921.77**	**921.77**	**921.77**	**921.77**
Reserve Planning Margin Already in Place																				
Agreement under Canal Plant Agreement to share Spinning Reserve (MW)	23.04	23.04	23.04	23.04	23.04	23.04	23.04	23.04	23.04	23.04	23.04	23.04	23.04	23.04	23.04	23.04	23.04	23.04	23.04	23.04
Total in Place (MW)	**23.04**	**23.04**	**23.04**	**23.04**	**23.04**	**23.04**	**23.04**	**23.04**	**23.04**	**23.04**	**23.04**	**23.04**	**23.04**	**23.04**	**23.04**	**23.04**	**23.04**	**23.04**	**23.04**	**23.04**
Additional Reserve that Should be Included in Resource Plan (MW)	**38.33**	**39.15**	**40.29**	**41.43**	**42.53**	**43.21**	**43.90**	**44.32**	**44.78**	**45.30**	**45.85**	**46.46**	**46.86**	**47.32**	**47.79**	**48.31**	**48.89**	**49.31**	**49.77**	**50.24**

13. References

1/ Canal Plant Agreement, effective date July 1, 2005, Parties to the Agreement were British Columbia Hydro and Power Authority, FortisBC Inc., Teck Cominco Metals Ltd., Brilliant Power Corporation, Brilliant Expansion Power Corporation, Waneta Expansion Power Corporation.

2/WEEC Standard BAL-STD-002-0-Operating Reserves

3) Power Purchase Agreement Made as of 1st Day on October 1993. Between BC Hydro and West Kootenay Power. First Revision of Supplement No.3 Effective October 1, 1993. Commission Order G-85-93.

4) BC Hydro – 2006 Integrated Electricity Plan

5) Discussions with Bruce Prior, Consultant, September 10 to September 28, 2007

6) Discussion with Tim Newton, Western Electricity Coordinating Council Director, September 14, 2007.

7) Discussion with Stephen Tran, British Columbia Transmission Corporation, September 26, 2007

8) Discussion with Doug Robinson, British Columbia Hydro, September 27, 2007.

Fortis BC
20 Year Resource Adequacy Study

REV	DATE:	COMMENTS
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Fortis BC Generation Resource Adequacy Report

Final Report November 30, 2007.

Executive Summary

A reliability analysis was undertaken of the Fortis BC system to determine resource adequacy requirements for the next twenty years. Several scenarios were defined with different generation mixes representing likely options. A defacto reliability standard was used as the target reliability for Loss of Load Estimation of LOLE. The target is 0.1 day /year – a widely accepted reliability criterion used in North America.

This study did not model the spot or short term market – this is considered to be beyond the scope of this study and indeed, likely beyond the current ability of reliability analysis techniques. Purchases are all assumed to be made in advance of each year in the study period and on a firm basis. (It is not known what the likelihood or probability is of being able to make these purchases.)

Therefore in this study a LOLE can be taken to mean either a genuine loss-of-load following an outage, in a future where there are no surpluses available in the market or, in the case where there are surpluses available, a need to go to that market on a spot or short-term basis. Meeting the LOLE criterion would mean a rare need to go to that market in this latter case.

The best performing option is where all new generation is purchased from reliable BC Hydro sources. This option exhibited the lowest planning margins needed to meet load growth, with good performance in high load growth scenarios (ie. lower planning margins in year 2027). Fortis required 224 MW of new generation to meet the LOLE target in the year 2008, 330 MW by 2017, and 417 MW by 2027. Planning margins are low at 11.5%, 9.6%, and 8.5%. See the Table on page 23 for a summary of the results.

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Introduction

The FortisBC power system has a dependable capacity of about 555 MW from 19 generator units totalling about 355 MW, including the Brilliant units under the Brilliant Power Purchase Agreement with Columbia Power), and also a firm power purchase agreement with BC Hydro for 200MW. Based on its load and demand-side management (DSM) forecast data, the peak load will reach about 780 MW in 2013. Expected reduction from DSM in 2013 is expected to be about 10 MW.

This results in a generation shortage of about 215 MW in 2013 (i.e., a negative planning margin), meaning that the FortisBC resources are unlike many utilities in Canada which plan firm long term resources with total dependable capacity which exceeds the expected peak demand by some positive margin so as to achieve some acceptable loss-of-load expectation (LOLE)

FortisBC's existing practise to mitigate the generation shortage is to make short term power purchases from Teck Cominco Metals (TCM), BC Hydro (BCH) and the Mid-Columbia (Mid-C) market in the United States. Since these purchases are from surpluses in the region which are diminishing over time, FortisBC is concerned that this practise may not be sustainable in which case it will have to augment its long-term firm resource portfolio.

This study determines the planning margins that would be needed to achieve an acceptable loss-of-load expectation (LOLE) under scenarios in which the existing resources are augmented by various long-term resources. Options examined include unit-contingent purchases from TCM, BC Hydro, the market, and also from new CCGT plants.

In this study, reliability assessment will be performed for FortisBC power system with use of Risk_A software originally developed by BC Hydro considering various system conditions and load forecast variations. The reliability index Loss-of-load Expectation (LOLE), in days, while generation supply being unable to serve its daily peak demand will be calculated under various long-term firm resource scenarios. In case of the LOLE in excess of a criterion of one day in a ten-year period, the capacity planning margin needed to meet that criterion will be computed.

Background

RISK_A is a software tool developed for system planning engineers to perform reliability analysis for a single-area power system; it is based on a sequential Monte Carlo method [4], a widely accepted method for accurate evaluation of power system reliability indexes. RISK_A simulates operations of a power system by sequentially stepping through years specified and with a time step defined by users, tracks all system transitions that occur, and produces the values as well as histogram distributions of following reliability indexes [1]:

- Loss of Load Frequency (LOLF), or Expected Number of Load Curtailments in occurrences/yr.
- Loss of Load Duration (LOLD) in hrs/occurrence.
- Loss of Load Expectation (LOLE) in hrs/yr.
- Expected Demand Not Served (DNS) in MW/year and Energy Not Served (ENS) in MW hr/year

- Loss of Load Probability (LOLP) or Probability of Load Curtailments.

The generation and load models are used to formulate the appropriate risk model, while transmission constraints will not be modelled for this type of study. The reliability indices LOLE will be analyzed for a period up to a 20-year horizon. The reliability criteria used in the assessment will be LOLE metric less than 1 day in ten years (or 0.1 day/per year) as commonly used in many utilities [2] including BC Hydro [12].

The following approaches will be used in the system modelling. For modelling of generators, the standard techniques described in [4] have been employed, with extensions for seasonal de-ratings of generators. In this study generator de-rates have not been modelled. In the load modeling, Risk_A uses a fixed load curve in a input text file for a simulation period (usually the annual load curve), with a sampling interval that matches simulation time step specified by users, in this study 1 hour was used.

Purchases from interconnected systems were modeled with equivalent generators as described below in the case descriptions.

Loss of Load Expectation (LOLE)

The loss of load expectation (LOLE) is one of the basic indices in the resource adequacy assessment methodology. The LOLE is the average number of days or hours in a given period of *T* (usually one year) in which the daily peak load or hourly load is expected to exceed the available generating capacity. This can be expressed mathematically as

$$\text{LOLE(days/yr or hr/yr)} = \sum_{i \in S} p_i T$$

where p_i is the probability of system state *i* and *S* is the set of all system states associated with loss of load. It should be noted that the daily LOLE depends on the comparison between the daily peak load and the available generating capacity [4].

We must highlight that the meanings and calculations of LOLE in d/yr (DLOLE) or hr/hr (HLOLE) are quite different and cannot be directly related to each other (ie. 2.4 hr/yr does not equate to 0.1 d/yr) [13]. "Different reliability indices are obtained using different load models. The LOLE index in hours is evaluated using hourly load values. The LOLE index in days is evaluated using daily peak load values." The index of 0.1 d/yr cannot be simply converted into 2.4 hr/yr because the hourly load profile is different than that of the daily peak load. The relationship between the indexes is complex and is dependent on load factor, the number of generating units, the type of generation, and the system size. Typically the ratio of Hourly LOLE to Daily LOLE ranges from 7 to15.

Generation resource adequacies calculated by using the 0.1 d/yr metric are more pessimistic then margins calculated using the hr/yr metric for the same system. It should be noted that the indices are equivalent when a constant peak load is used with a load factor of 1.

To prove that DLOLE in d/yr are equal to HLOLE in hr/yr divided by 24, we offer the following treatment. Considering Multistep Model of Annual load Curves as defined in reference [4]; pp. 93

One technique for modelling an annual load curve in practice is called the multistep model [4]. With this concept we can prove the DLOLE can be derived by the hourly HLOLE using the multistep model of an annual load curve.

Assume that a load curve is divided into N level steps and $i-th$ step includes N_i load points, the probability of the $i-th$ step is

$$P_i = N_i/8760$$

The annual reliability indices considering the multistep model of the annual load curve can be obtained by

$$\mathrm{LOLE} = \sum_{i=1}^{N} \left(\mathrm{LOLE}_i \times P_i\right)$$

In our case, $N = 365$, $N_i = 24$, which gives

$$\mathrm{LOLE} = \sum_{i=1}^{365} \left(\mathrm{LOLE}_i \times \frac{24}{8760} \right) = \frac{1}{365} \sum_{i=1}^{365} \mathrm{LOLE}_i$$

HLOLE is the system hourly value, and LOLE_i is the hourly LOLE obtained with a flat load duration curve whose peak value is that of $i-th$ step of multistep model.
It is noted that the ratio between the HLOLE (hrs/yr) and the DLOLE (days/yr) is 24 when the annual load factor is unity. To prove that the DLOLE is equal to the HLOLE / 24 for a daily load factor of 1 for a 1 year period, from Equation (4), we have

$$\mathrm{LOLE}/24 = \frac{1}{365} \sum_{i=1}^{365} \mathrm{LOLE}_i/24$$

Thus

$$\mathrm{LOLE}/24 = \frac{1}{365} \sum_{i=1}^{365} \mathrm{DLOLE}_i = \mathrm{DLOLE}$$

Risk_A calculates hourly LOLE by accumulating the hours where generation is insufficient to meet capacity. DLOLE is calculated by using daily peak load for every hour of the day and calculating LOLE in hours for 8760 hours. The DLOLE d/yr results are presented here with the HLOLE hr/yr results included in Appendix D for comparison purposes.

Data Preparation

The data supplied by Fortis BC included over ten years of historical hourly system load readings, single line diagram, twenty year load forecast with estimated Demand Side Management program savings, the generation unit forced outage rates and duration data, and a number of scenarios that are likely for a supply of new generation. All data sources have been included on the CD-ROM for future reference.

Conditioning of the data is important for the preparation and formulation of the cases. An annual chronological load curve is necessary and the one used in this study is discussed below.

The forced outage data also had to be formulated into a format that the Risk_A program would accept. This is also described below.

Load Duration Curve

The load duration curve is a critical part of the data supplied to the Risk_A solution engine. A chronological hourly data file is needed for each year of study; 8760 entries in free format text. These readings are per unitized or normalized to its peak value. Fortis BC provided over 10 years of historical system hourly data from 1997 to May of 2007. Ten years (1997 to 2006) hourly load readings were numerically averaged over each year, to create an average representative load duration curve. The year 2000 and 2004 leap days were ignored in this calculation. The load factor for average annual hourly load curve is 62%.

The peak reading of each day was taken as the maximum load for that day and used 24 times for the hourly time step as per the LOLE calculation (Equation 1). This was necessary to produce the correct results for Daily LOLE calculations consistent with the definition of an LOLE equal to 0.1 day/yr.

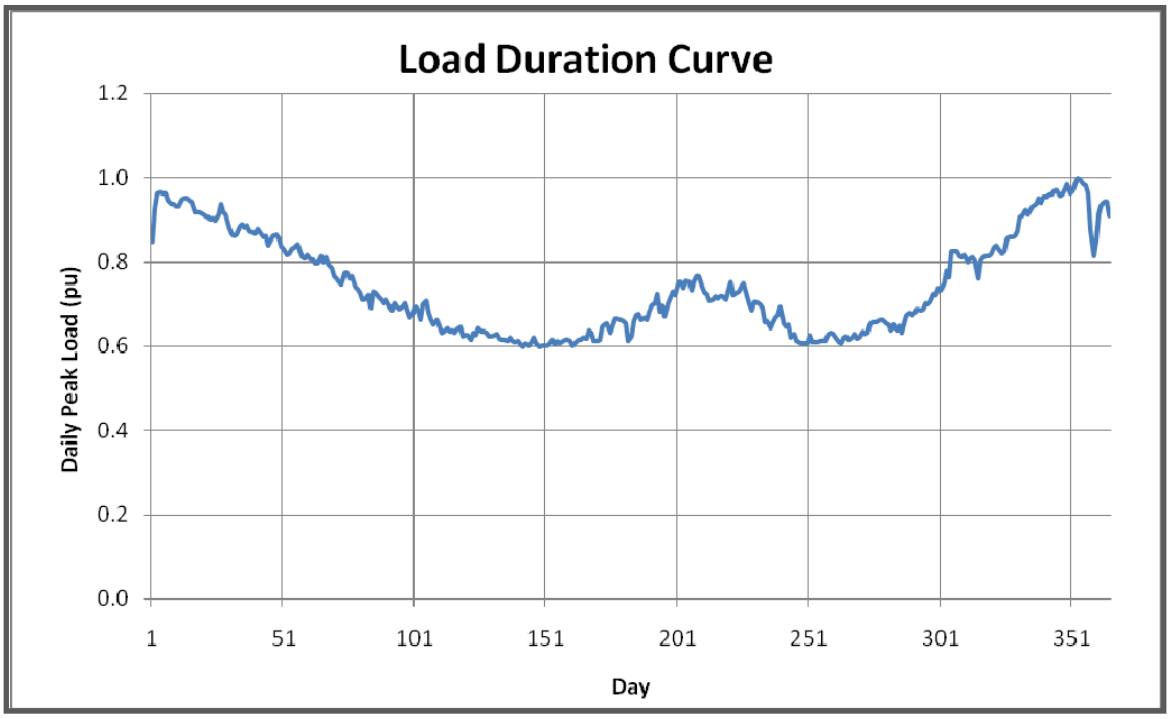

Figure 1: Load Duration Curve

Generation Outage Data

The Fortis BC generations units are run occasionally when needed to optimize river flows for the entire BC Hydro system. The equivalent capacity is available from BC Hydro when the plants are not running thus the effect is similar to having all units available for service when needed. The unit capacities are listed below and a reduction of 4.5% to account for spinning reserve has been applied. The Table 13 in Appendix B provides all details for unit capacities, forced outages rates, and maintenance rates.

Load Forecast Data

Fortis BC has provided a twenty year load forecast with load uncertainty modeled with low, expected, and high load indices. The probability of the load meeting the expected is 80%, with a 10% probability for both the low and high loads. This data is shown in the Appendix A: Load Forecast.

A Demand Side Management program is in place at Fortis BC which expects to reduce their generation requirements by 23 MW by the year 2027. This has been factored into this study by reducing the load forecast by this amount to determine the new generation requirement to make up the difference.

Case Scenarios

The following scenarios were determined to provide an overview of options practically available to Fortis BC to meet their future load demands. These scenarios are grouped into three areas, with three options each. There are twenty years of load to be modeled all with low, expected, and high variants for a total of 15 variants for each case.

CASE	DESCRIPTION
1	Base Case – TeckCominco only
2	Base Case – TeckCominco with 50MW from MID-C, 50MW from BC Hydro
3	Base Case – TeckCominco with 100MW from MID-C 1, 100MW from BC Hydro.
4	Base Case – CCGT only
5	Base Case – CCGT with 50MW from MID-C, 50MW from BC Hydro
6	Base Case – CCGT with 100MW from MID-C 1, 100MW from BC Hydro.
7	Base Case – BC Hydro only
8	Base Case – BC Hydro with 50MW from MID-C, 50MW from BC Hydro
9	Base Case – BC Hydro with 100MW from MID-C 1, 100MW from BC Hydro

Table 1: Case Scenarios

Case 1 base case models a long term purchase from TeckCominco (TCM) on a unit commitment basis. The reliability of the machines needs to be modelled with their full forced outage data to be realistic for this option. Since we don't know which generator will be used to supply Fortis BC, an aggregate forced outages rates were calculated based on data supplied. The magnitude of the purchase was varied as necessary to achieve the one day in ten years LOLE criterion.

Case 2 and Case 3 models a purchase from TCM, plus a share from Market 1 (MID-C) and Market 2 (BC Hydro). The Risk Analysis tool does not model the probability that the market transaction will be successful, only that the market transaction is in place, then forced out on it's FOR and duration. As there are a number of strong connections to BC Hydro and the purchase is expected to be from the BCH system rather than any specific units, the forced outage rates for the BCH purchases were modelled as ideal (FR equal to 0.0, and FT equal to 0.0). The MID-C market was assumed to supply the purchase on a unit-contingent basis from surplus gas turbines generators. The forced outage rates associated with this transaction used all CCGT units from the CEA Equipment Reliability Information System Annual Report for 2005 [11].

Case 4, 5, and 6 are similar to Cases 1 – 3 except that a new Combined Cycle Combustion Turbine is used instead of TCM.

Cases 7, 8, and 9 model a purchase of generation capacity from BC Hydro with similar participation from the MID-C and PowerEx (BC Hydro) markets.

Market Model – Literature Review

To determine methods for modeling market reliability in generation resource adequacy studies, a scientific literature search was performed and the results are discussed here.

Reliability analysis is usually conducted on separate segments of the power system with evaluation of generating facilities, transmission systems, and distribution system performed independently with different indices or metrics for each. The reliability indices obtained for each segment are then used to make decisions based on their performance. This kind of analysis assumes that the other parts of the system are independent and capable of performing their intended functions. To study the effects of the market environment, the segments include business related dependencies (such as energy price, long term contracts, ancillary services, transmission constraints and fixed transmission rights). Today, reliability evaluation is limited to physical systems with

measurable data. A great deal of research is needed to adequately characterize the reliability of the market.

References and literatures are more focused on the new challenges arising due to the market environment [5] [6] [7] [8] [9] [10]; it seems there is lack of well developed methods or theory on how to perform reliability evaluation in the deregulated market environment.

Thus, to model the MID-C market in the U.S., it is assumed that the purchase has been made from surplus gas turbines. The forced outage rates associated with this transaction were derived with average values for all listed CCGT units from the ERIS report [11].

Model Development

The model used with the Risk_A program contains details about the generation available, the new generation needed from either purchases or new generators, and the system load. The transmission system is model as ideal without consideration to the transmission system reliability or constraints. This practice is consistent for Hierarchical Level 1 studies for generation resource indices as defined by Roy Billinton and Wenyuan Li (BC Hydro) [1][4].

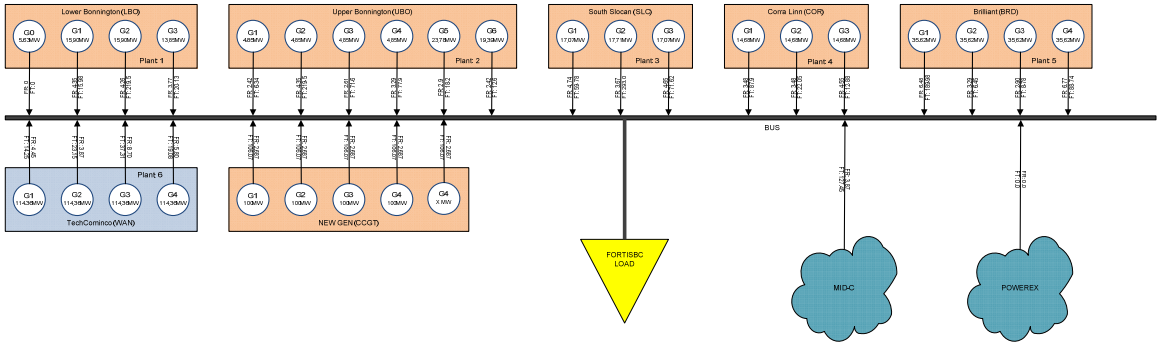

Figure 2: Reliability System Diagram

Data files

Input to the simulations in the form of text files defined by the Risk_A Program Operations manual [1]. Generators use a “generator record” while the load uses a “customer record”. All generators and loads terminate on a bus record modeling the transmission system and providing connection from the generation to the load.

Many input files were prepared for each scenario and study year. The files were named ***caseXe_yN.txt*** where the case number ***X*** denotes 1 through 9, the letter ***e*** for expected load (l=low,e=expected, h=high), and the year ***N*** (0 – 19).

Risk_A program details

The Risk_A program is a command line tool that takes two type of input files, the hourly load curve for each load, the network description file, then runs a simulation based on programmed rules of sequential Monte Carlo simulation methods. Several output files are produced, a DNS or demand not served file, and ITR or iteration detail file, a log file of all program internal operations, and the STS file or Statistics file that contain the important output for determination of LOLE. The amount of new generation was adjusted until for each simulation until the LOLE was less or near 2.4 hours / year which equates to 0.1 day/yr when daily peak loads are used with a load factor of 1 for each day. These results were tabulated together with the amount of generation to calculate Generation Resource Planning margins.

Results

The results portray the required generation to meet the NERC defacto standard of 1 day in a 10 year period, or 0.1 day per year. Risk_A calculate LOLE indices in hours thus 0.1 day is equivalent to 2.4 hours when the load data is conditioned and daily peak loads are used for each hour. This forms the target index for all simulations.

With expected load in a year, and a specified amount of new generation and existing generation, the reserve needed to meet or exceed the 0.1 day per year target was computed for all cases, and in representative years (every five years of the study period). This data is captured in the following tables and charts contained in the case result sections.

CASE 1 Results

The case 1 scenario models all the existing Fortis BC long term firm resources with its reliability indices, DSM load reductions, and the required firm generation purchase from the TCM Waneta plant on a unit-contingent basis in order to reach a target of 0.1 day/year LOLE. In this case, Fortis required 305MW of generation from TCM to meet the target in the year 2008, 424MW by 2017, and 526MW by 2027. (The latter is hypothetical since the Waneta maximum dependable output is 479 MW.) Margins required to meet criteria range from 22.9% to 20.5%

Observed trends on whether the planning margin increases, decreases, or stays approximately the same depends wholly on the scenario. When the planning margin decreases, we can conclude that the proportion of new generation added has a higher reliability and thus less is needed to meet the 0.1 day/yr LOLE target. If the planning margin increases, the opposite is true and the new generation is less reliable than the existing mix and more is required. This makes sense when we add a large portion of CCGTs that have poorer performance than hydro units that are only used occasionally as in the Fortis BC case.

COMMON ELEMENTS			CASE 1: TCM only					
Year	Fortis BC	BCH3808	Low	Margin	Expected	Margin	High	Margin
2008	368.8	200.0	304	22.9%	305	22.9%	306	22.8%
2009	368.8	200.0						
2010	368.8	200.0						
2011	368.8	200.0						
2012	368.8	200.0	348	22.2%	370	22.0%	394	21.3%
2013	368.8	200.0						
2014	368.8	200.0						
2015	368.8	200.0						
2016	368.8	200.0						
2017	368.8	200.0	390	21.7%	424	21.1%	472	20.7%
2018	368.8	200.0						
2019	368.8	200.0						
2020	368.8	200.0						
2021	368.8	200.0						
2022	368.8	200.0	431	21.0%	478	20.9%	544	20.4%
2023	368.8	200.0						
2024	368.8	200.0						
2025	368.8	200.0						
2026	368.8	200.0						
2027	368.8	200.0	472	20.8%	526	20.5%	617.5	20.7%

Table 2: Case 1 DLOLE Results

The TCM trend line is a linear curve fit of the 5 data points used for charting purposes. The chart below shows the entire generation mix with area curves against the expected load forecast curve. The new generation required flattens as TCM only has 479MW of dispatchable unit commitment.

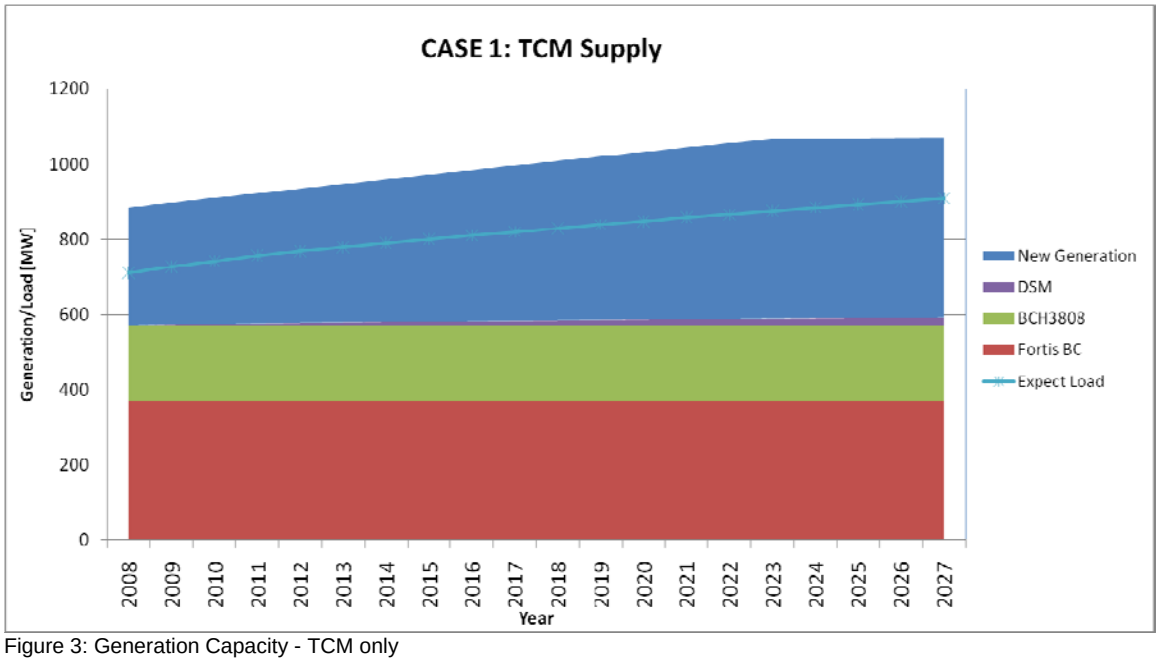

Figure 3: Generation Capacity - TCM only

As most case result charts are very similar, only case 1 is shown here for illustrative purposes and all charts are included in Appendix D.

CASE 2 Results

The case 2 scenario is the same as Case 1 except with additional firm purchases of 50MW from the MID-C market and 50MW from Powerex (BC Hydro marketing subsidiary). As in Case 1, the results show the required generation from TCM needed in order to reach the target of 0.1 day/year LOLE.

COMMON ELEMENTS			CASE 2: 100MW + TCM					
Year	Fortis BC	BCH3808	**Low**	**Margin**	**Expected**	**Margin**	**High**	**Margin**
2008	368.8	200.0	298	22.1%	300	22.2%	301	22.1%
2009	368.8	200.0						
2010	368.8	200.0						
2011	368.8	200.0						
2012	368.8	200.0	351	22.5%	369	21.9%	395	21.5%
2013	368.8	200.0						
2014	368.8	200.0						
2015	368.8	200.0						
2016	368.8	200.0						
2017	368.8	200.0	390	21.7%	424	21.1%	471	20.6%
2018	368.8	200.0						
2019	368.8	200.0						
2020	368.8	200.0						
2021	368.8	200.0						
2022	368.8	200.0	430	20.9%	475	20.5%	535	19.4%
2023	368.8	200.0						
2024	368.8	200.0						
2025	368.8	200.0						
2026	368.8	200.0						
2027	368.8	200.0	471	20.7%	519	19.7%	603	19.2%

Table 3: Case 2 DLOLE Results

In this case, Fortis required 300MW of generation to meet the target in the year 2008, 424 MW by 2017, and 519MW by 2027, with planning margins of 22.2%, 21.1%, and 19.7%. For the expected load, this case has approximately the same performance as Case 1: however, for high load calculation, we see the planning margin range from 22.1% 2008 to 19.2% in 2027. We can conclude that the 50 MW from the MID-C market together with TCM generators have a poorer reliability performance overall. This case is hypothetical since the total maximum dependable output from TCM is 479MW – 503MW (603MW – 100MW from the market) are needed to meet the LOLE target.

CASE 3 Results

The case 3 scenario is as Case 2 except that there are 100MW purchases from the MID-C market and 100MW from Powerex.

COMMON ELEMENTS			CASE 3: 200 MW + TCM					
Year	Fortis BC	BCH3808	**Low**	**Margin**	**Expected**	**Margin**	**High**	**Margin**
2008	368.8	200.0	302	22.6%	305	22.9%	306	22.8%
2009	368.8	200.0						
2010	368.8	200.0						
2011	368.8	200.0						
2012	368.8	200.0	350	22.4%	370	22.0%	402	22.4%
2013	368.8	200.0						
2014	368.8	200.0						
2015	368.8	200.0						
2016	368.8	200.0						
2017	368.8	200.0	395	22.3%	450	24.2%	492	23.1%
2018	368.8	200.0						
2019	368.8	200.0						
2020	368.8	200.0						
2021	368.8	200.0						
2022	368.8	200.0	456	24.0%	496	22.9%	564	22.6%
2023	368.8	200.0						
2024	368.8	200.0						
2025	368.8	200.0						
2026	368.8	200.0						
2027	368.8	200.0	492	23.1%	548	22.9%	622	21.1%

Table 4: Case 3 DLOLE Results

In this case, Fortis BC required 105MW of generation from TCM to meet its targets in the year 2008, 250 MW by 2017, and 348MW by 2027, with margins of 22.9% 24.2% and 22.9%. The results of this case are approximately similar to Case 1 except that there is a small increase in planning margin which then decreases in subsequent years. The Monte Carlos simulation works on non-linear systems and the results for this case have a noticeable maxima at 450MW.

CASE 4 Results

The case 4 scenario is as Case 1 except that the new resources needed to reach the target of 0.1 day/year LOLE are from a new Combined Cycle Gas Turbine (CCGT) instead of TCM.

COMMON ELEMENTS			CASE 4: CCGT only					
Year	Fortis BC	BCH3808	**Low**	**Margin**	**Expected**	**Margin**	**High**	**Margin**
2008	368.8	200.0	330	26.6%	333	26.8%	334	26.8%
2009	368.8	200.0						
2010	368.8	200.0						
2011	368.8	200.0						
2012	368.8	200.0	373	25.5%	405	26.6%	429	25.8%
2013	368.8	200.0						
2014	368.8	200.0						
2015	368.8	200.0						
2016	368.8	200.0						
2017	368.8	200.0	422	25.7%	457	25.1%	509	25.0%
2018	368.8	200.0						
2019	368.8	200.0						
2020	368.8	200.0						
2021	368.8	200.0						
2022	368.8	200.0	465	25.1%	513	24.9%	573	23.6%
2023	368.8	200.0						
2024	368.8	200.0						
2025	368.8	200.0						
2026	368.8	200.0						
2027	368.8	200.0	510	25.2%	559	24.1%	638	22.8%

Table 5: Case 4 DLOLE Results

In this case, Fortis required 333MW of generation from a new CCGT to meet its targets in the year 2008, 457 MW by 2017, and 559MW by 2027, with margins of 26.8%, 25.1% and 24.1% respectively. The large margins are a product of forced outage rates and outage durations for CCGT units. From the ERIS document, the aggregate outage time is much longer than the recorded outage times for Fortis BC hydro units. As load grows, more CCGT generation is needed based on their reliability characteristics. These units were sized with multiple 100MW units, and the balance in a smaller turbine.

CASE 5 Results

Case 5 is as Case 4 except that there are purchases of 50 MW from the MID-C market and 50MW from Powerex.

COMMON ELEMENTS			CASE 5: 100MW + CCGT					
Year	Fortis BC	BCH3808	**Low**	**Margin**	**Expected**	**Margin**	**High**	**Margin**
2008	368.8	200.0	308	23.4%	311	23.7%	313	23.8%
2009	368.8	200.0						
2010	368.8	200.0						
2011	368.8	200.0						
2012	368.8	200.0	351	22.6%	380	23.3%	412	23.6%
2013	368.8	200.0						
2014	368.8	200.0						
2015	368.8	200.0						
2016	368.8	200.0						
2017	368.8	200.0	407	23.8%	440	23.0%	500	24.0%
2018	368.8	200.0						
2019	368.8	200.0						
2020	368.8	200.0						
2021	368.8	200.0						
2022	368.8	200.0	445	22.7%	505	24.0%	569	23.1%
2023	368.8	200.0						
2024	368.8	200.0						
2025	368.8	200.0						
2026	368.8	200.0						
2027	368.8	200.0	500	24.0%	545	22.6%	632	22.2%

Table 6: Case 5 DLOLE Results

In this case, Fortis required 211MW of generation from a new CCGT to meet its targets in the year 2008, 340 MW by 2017, and 445MW by 2027. The largest CCGT unit was 100MW with the balance in a smaller turbine. The planning margins are 23.7%, 23%, and 22.6% respectively.

CASE 6 Results

Case 6 is as Case 5 except with larger purchases from the market and Powerex of 100 MW each.

COMMON ELEMENTS			CASE 6: 200 MW + CCGT					
Year	Fortis BC	BCH3808	**Low**	**Margin**	**Expected**	**Margin**	**High**	**Margin**
2008	368.8	200.0	315	24.4%	320	25.0%	325	25.5%
2009	368.8	200.0						
2010	368.8	200.0						
2011	368.8	200.0						
2012	368.8	200.0	368	24.8%	395	25.3%	432	26.1%
2013	368.8	200.0						
2014	368.8	200.0						
2015	368.8	200.0						
2016	368.8	200.0						
2017	368.8	200.0	427	26.4%	450	24.2%	502	24.2%
2018	368.8	200.0						
2019	368.8	200.0						
2020	368.8	200.0						
2021	368.8	200.0						
2022	368.8	200.0	466	25.2%	505	24.0%	566	22.8%
2023	368.8	200.0						
2024	368.8	200.0						
2025	368.8	200.0						
2026	368.8	200.0						
2027	368.8	200.0	502	24.2%	550	23.1%	641	23.1%

Table 7: Case 6 DLOLE Results

In this case, Fortis required 120 MW of generation from a new CCGT to meet its targets in the year 2008, 250 MW by 2017, and 350 MW by 2027. Planning margins ranged from 25.0% to 23.1% for expected load, and 25.5% to 23.1% for high load scenarios. For the 2027 year, a total of 641 MW of new generation (MID-C, Powerex, and CCGT) is needed to meet reliability targets.

CASE 7 Results

Case 7 models the Fortis BC system with a new generation purchase is from BCH for the entire requirement.

COMMON ELEMENTS			CASE 7: BCH only					
Year	Fortis BC	BCH3808	**Low**	**Margin**	**Expected**	**Margin**	**High**	**Margin**
2008	368.8	200.0	223	11.5%	224	11.5%	225	11.5%
2009	368.8	200.0						
2010	368.8	200.0						
2011	368.8	200.0						
2012	368.8	200.0	262	10.7%	280	10.3%	304	10.0%
2013	368.8	200.0						
2014	368.8	200.0						
2015	368.8	200.0						
2016	368.8	200.0						
2017	368.8	200.0	299	10.1%	330	9.6%	371	9.0%
2018	368.8	200.0						
2019	368.8	200.0						
2020	368.8	200.0						
2021	368.8	200.0						
2022	368.8	200.0	336	9.5%	375	9.0%	432	8.3%
2023	368.8	200.0						
2024	368.8	200.0						
2025	368.8	200.0						
2026	368.8	200.0						
2027	368.8	200.0	371	9.1%	417	8.5%	489	7.6%

Table 8: Case 7 DLOLE Results

In this case, Fortis required 224 MW of new generation to meet its targets in the year 2008, 330 MW by 2017, and 417 MW by 2027. Planning margins are low at 11.5%, 9.6%, and 8.5%. These margins are lower than other scenarios as the total generation from BC Hydro is assumed to have an ideal reliability. This assumption is relatively safe (see caveat below) as examination of the Fortis BC system indicates that there are five connection points to the BC Hydro transmission system. It is unlikely that more two connections will be out of service during peak loading conditions, and that BC Hydro will be carrying the spinning reserve needed to meets its share of the largest contingency in the WECC system.

This ideal reliability assumption needs further examination on the BCTC system for thermal constraints, or other constrained boundaries that may impact the load serving ability of this system to Fortis BC.

CASE 8 Results

Case 8 is as Case 7 except that there are purchases of 50 MW each from Mid-C and from Powerex.

COMMON ELEMENTS			CASE 8: 100MW + BCH					
Year	Fortis BC	BCH3808	**Low**	**Margin**	**Expected**	**Margin**	**High**	**Margin**
2008	368.8	200.0	239	13.7%	242	14.0%	245	14.3%
2009	368.8	200.0						
2010	368.8	200.0						
2011	368.8	200.0						
2012	368.8	200.0	278	12.8%	297	12.5%	320	12.0%
2013	368.8	200.0						
2014	368.8	200.0						
2015	368.8	200.0						
2016	368.8	200.0						
2017	368.8	200.0	315	12.1%	346	11.6%	387	10.9%
2018	368.8	200.0						
2019	368.8	200.0						
2020	368.8	200.0						
2021	368.8	200.0						
2022	368.8	200.0	352	11.5%	391	10.8%	448	10.0%
2023	368.8	200.0						
2024	368.8	200.0						
2025	368.8	200.0						
2026	368.8	200.0						
2027	368.8	200.0	387	10.9%	434	10.4%	506	9.4%

Table 9: Case 8 DLOLE Results

In this case, Fortis required 242 MW of new generation to meet its targets in the year 2008, 346 MW by 2017, and 434 MW by 2027. The planning margins are 14.0%, 11.6%, and 10.4%, all higher than that of case 7 with the added MID-C generation from surplus gas turbines.

CASE 9 Results

Case 9 is as Case 8 except with larger purchases from Mid-C and Powerex

COMMON ELEMENTS			CASE 9: 200 MW + BCH					
Year	Fortis BC	BCH3808	**Low**	**Margin**	**Expected**	**Margin**	**High**	**Margin**
2008	368.8	200.0	287	20.5%	288	20.5%	289	20.4%
2009	368.8	200.0						
2010	368.8	200.0						
2011	368.8	200.0						
2012	368.8	200.0	326	19.2%	344	18.6%	368	18.1%
2013	368.8	200.0						
2014	368.8	200.0						
2015	368.8	200.0						
2016	368.8	200.0						
2017	368.8	200.0	362	18.1%	393	17.3%	434	16.3%
2018	368.8	200.0						
2019	368.8	200.0						
2020	368.8	200.0						
2021	368.8	200.0						
2022	368.8	200.0	399	17.2%	438	16.2%	496	15.2%
2023	368.8	200.0						
2024	368.8	200.0						
2025	368.8	200.0						
2026	368.8	200.0						
2027	368.8	200.0	434	16.4%	481	15.5%	553	14.2%

Table 10: Case 9 DLOLE Results

In this case, Fortis required 288 MW of new generation to meet its targets in the year 2008, 393 MW by 2017, and 481 MW by 2027. Planning margins are 20.5%, 17.3%, and 15.5%.

Conclusions

As can be seen in table below, the planning margins needed to meet a criterion of one day LOLE in a ten year period vary, depending on the type and mix of new generations resources added. The margin varies from a low of 7.6%, (case 7 high load) for the case where all of the new generation added comes from a long term firm system (i.e., not unit-contingent) purchases from BC Hydro, to a maximum of 26.8% (case 4 high load) where all of the new generation comes from CCGTs.

		2008	2012	2017	2022	2027
CASE 1	Low	22.9%	22.2%	21.7%	21.0%	20.8%
	Exp	22.9%	22.0%	21.1%	20.9%	20.5%
	High	22.8%	21.3%	20.7%	20.4%	20.7%
CASE 2	Low	22.1%	22.5%	21.7%	20.9%	20.7%
	Exp	22.2%	21.9%	21.1%	20.5%	19.7%
	High	22.1%	21.5%	20.6%	19.4%	19.2%
CASE 3	Low	22.6%	22.4%	22.3%	24.0%	23.1%
	Exp	22.9%	22.0%	24.2%	22.9%	22.9%
	High	22.8%	22.4%	23.1%	22.6%	21.1%
CASE 4	Low	26.6%	25.5%	25.7%	25.1%	25.2%
	Exp	26.8%	26.6%	25.1%	24.9%	24.1%
	High	26.8%	25.8%	25.0%	23.6%	22.8%
CASE 5	Low	23.4%	22.6%	23.8%	22.7%	24.0%
	Exp	23.7%	23.3%	23.0%	24.0%	22.6%
	High	23.8%	23.6%	24.0%	23.1%	22.2%
CASE 6	Low	24.4%	24.8%	26.4%	25.2%	24.2%
	Exp	25.0%	25.3%	24.2%	24.0%	23.1%
	High	25.5%	26.1%	24.2%	22.8%	23.1%
CASE 7	Low	11.5%	10.7%	10.1%	9.5%	9.1%
	Exp	11.5%	10.3%	9.6%	9.0%	8.5%
	High	11.5%	10.0%	9.0%	8.3%	7.6%
CASE 8	Low	13.7%	12.8%	12.1%	11.5%	10.9%
	Exp	14.0%	12.5%	11.6%	10.8%	10.4%
	High	14.3%	14.3%	10.9%	10.0%	9.4%
CASE 9	Low	20.5%	19.2%	18.1%	17.2%	16.4%
	Exp	20.5%	18.6%	17.3%	16.2%	15.5%
	High	20.4%	18.1%	16.3%	15.2%	14.2%

Table 11: Summary of Planning Margins

Please note that, as explained previously, the study did not model the spot or short term market – this is considered to be beyond the scope of this study and indeed, likely beyond the current ability of reliability analysis techniques. Purchases are all assumed to

be made in advance of each year in the study period and on a firm basis. (It is not known what the likelihood or probability is of being able to make these purchases.)

Therefore in this study a LOLE can be taken to mean either a genuine loss-of-load following an outage, in a future where there are no surpluses available in the market or, in the case where there are surpluses available, a need to go to that market on a spot or short-term basis. Meeting the LOLE criterion would mean a rare need to go to that market in this latter case.

The best performing option is case 7 where all new generation is purchased from reliable BC Hydro sources. This option exhibited the lowest planning margins needed to meet load growth, with good performance in high load growth scenarios (ie. Lower planning margins in year 2027).

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APPENDIX A: LOAD FORECAST

Year	Low Load	Expected	High Forecast
2008	712	713	714
2009	730	732	736
2010	741	749	759
2011	751	765	782
2012	759	778	802
2013	765	790	820
2014	772	801	837
2015	782	812	850
2016	792	823	862
2017	802	834	876
2018	810	845	891
2019	819	855	907
2020	828	865	918
2021	836	876	930
2022	845	885	943
2023	853	895	956
2024	860	905	971
2025	870	914	982
2026	878	923	994
2027	885	932	1006

Table 12: Annual load forecast

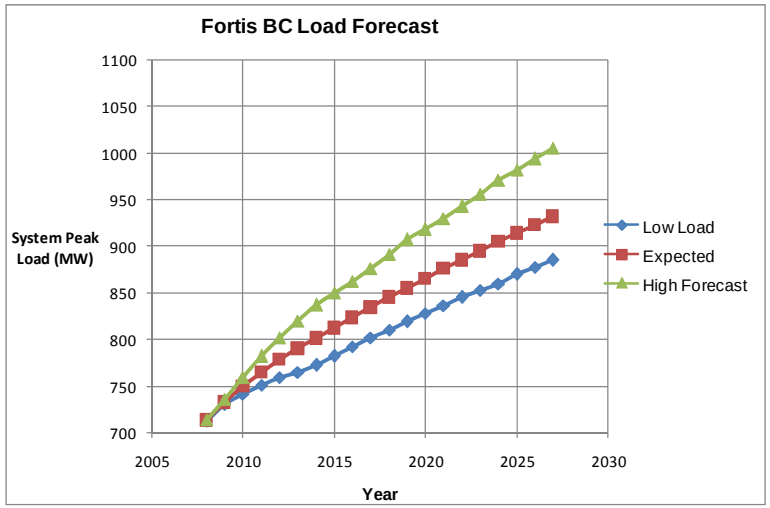

Figure 4: Fortis BC Load Forecast Chart

APPENDIX B: GENERATOR UNIT FORCED OUTAGE DATA

Plant			Generators						
#	Name	Gen. #	Name	MW			Fail		Maint.	
				Norminal	Spin Res.	Net Cap.	FR	Time	Rate	Time
1	Lower Bonnington	0	LBO-G0	5.90	4.5%	5.63	0		No	
		1	LBO-G1	16.65	4.5%	15.90	4.35	15.99		
		2	LBO-G2	16.65	4.5%	15.90	4.26	219.54		
		3	LBO-G3	14.50	4.5%	13.85	3.77	20.13		
				47.80						
2	Upper Bonnington	1	UBO-G1	5.07	4.5%	4.85	2.42	6.34	No	
		2	UBO-G2	5.07	4.5%	4.85	4.35	293.02		
		3	UBO-G3	5.07	4.5%	4.85	2.61	71.62		
		4	UBO-G4	5.07	4.5%	4.85	3.29	77.90		
		5	UBO-G5	24.90	4.5%	23.78	2.90	18.20		
		6	UBO-G6	20.30	4.5%	19.39	2.42	12.61		
				65.50						
3	Soth Slocan	1	SLC-G1	17.88	4.5%	17.07	4.74	59.79	No	
		2	SLC-G2	18.54	4.5%	17.71	3.68	293.02		
		3	SLC-G3	17.88	4.5%	17.07	4.65	71.62		
				54.30						
4	Corra Linn	1	COR-G1	15.37	4.5%	14.68	3.48	87.91	No	
		2	COR-G2	15.37	4.5%	14.68	3.48	22.05		
		3	COR-G3	15.37	4.5%	14.68	4.55	12.88		
				46.10						
5	Brilliant	1	BRD-G1	37.30	4.5%	35.62	6.48	189.99	1. 3 days in two yrs 2. 5 wks in 10 yrs	
		2	BRD-G2	37.30	4.5%	35.62	3.29	6.49		
		3	BRD-G3	37.30	4.5%	35.62	2.90	8.78		
		4	BRD-G4	37.30	4.5%	35.62	6.77	88.74		
				149.20						
6	Waneta	1	WAN-G1	119.75	4.5%	114.36	4.45	14.25	1. 3 days yearly, 2. #3 out 5 wks in 2009	
		2	WAN-G2	119.75	4.5%	114.36	3.87	23.16		
		3	WAN-G3	119.75	4.5%	114.36	8.71	37.31		
		4	WAN-G4	119.75	4.5%	114.36	5.81	19.08		
				479.00						

Table 13: Generator Unit Forced Outage Data

APPENDIX C: GENERATION MIX CHARTS

The following appendix contains the charts of generation resource mix for all scenario cases in this study.

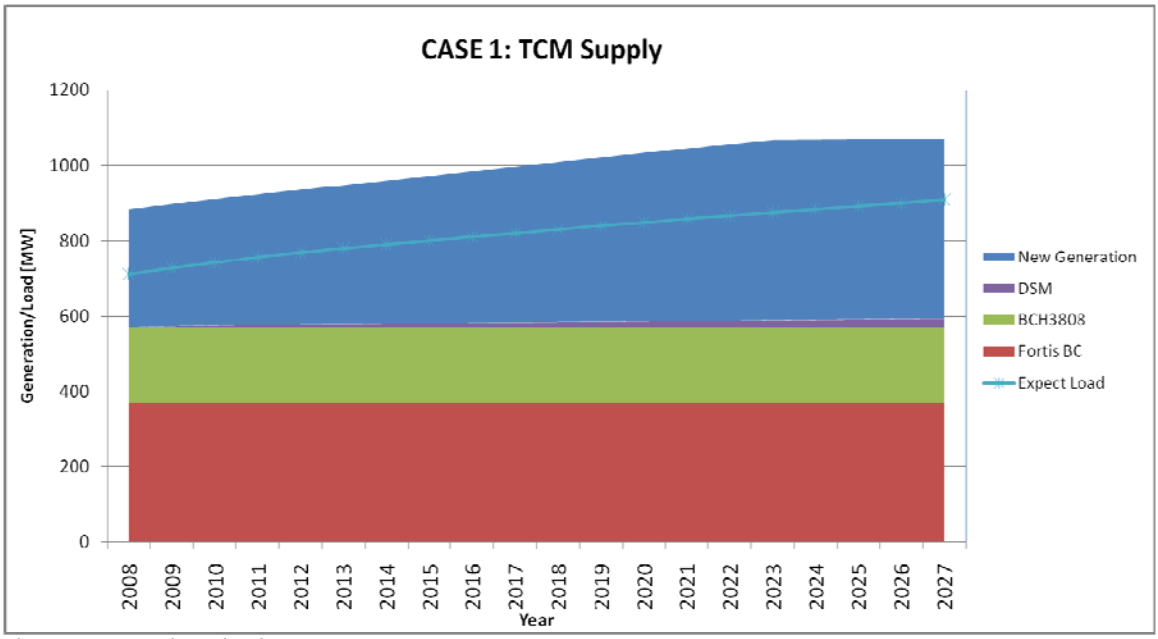

Figure 5: Generation Mix Chart - Case 1

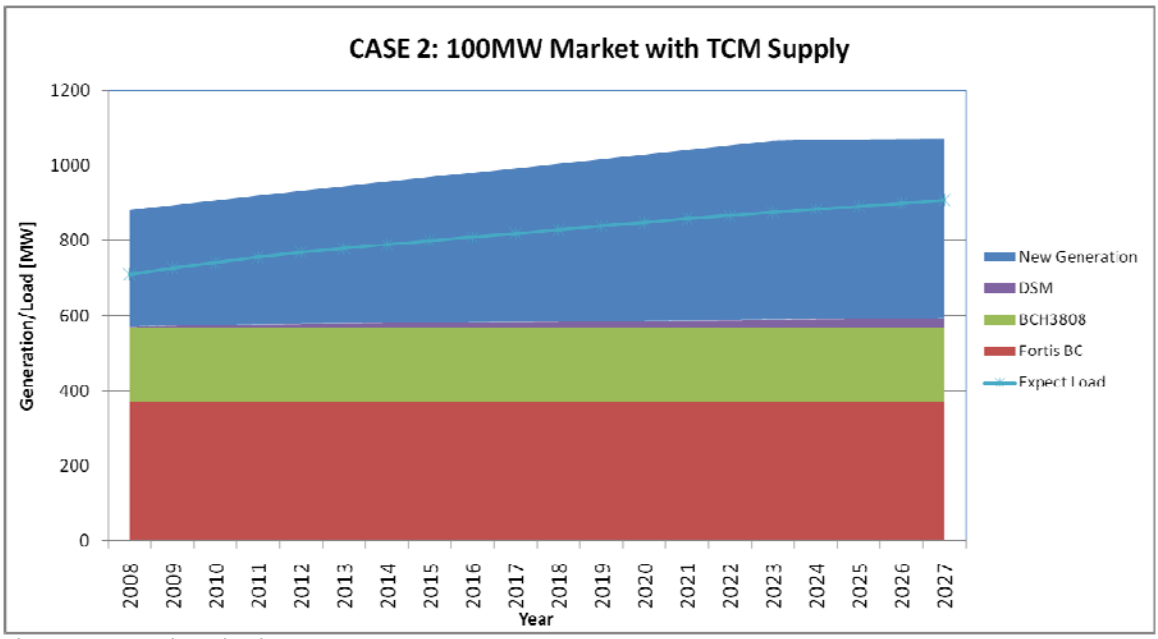

Figure 6: Generation Mix Chart - Case 2

APPENDIX C: GENERATION MIX CHARTS

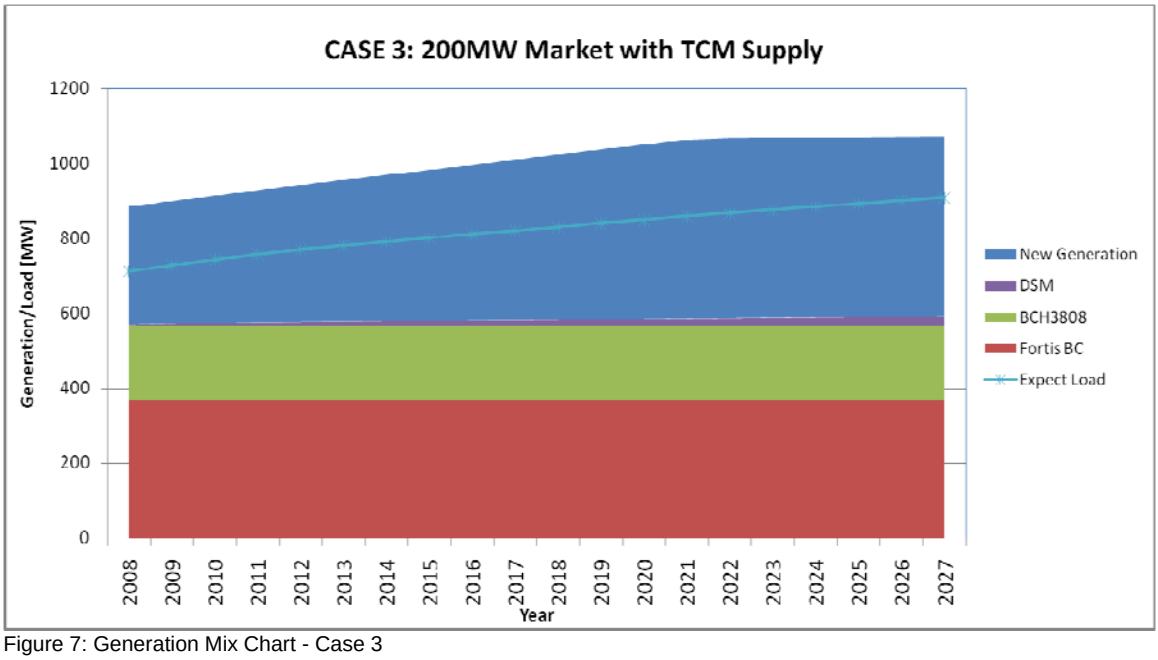

Figure 7: Generation Mix Chart - Case 3

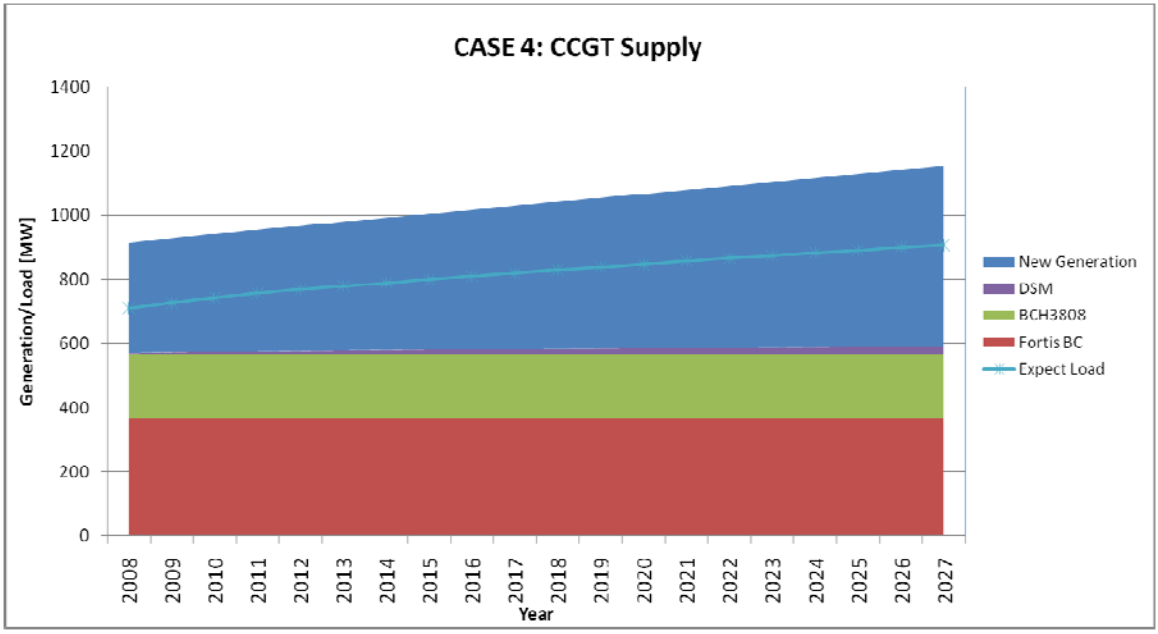

Figure 8: Generation Mix Chart - Case 4

APPENDIX C: GENERATION MIX CHARTS

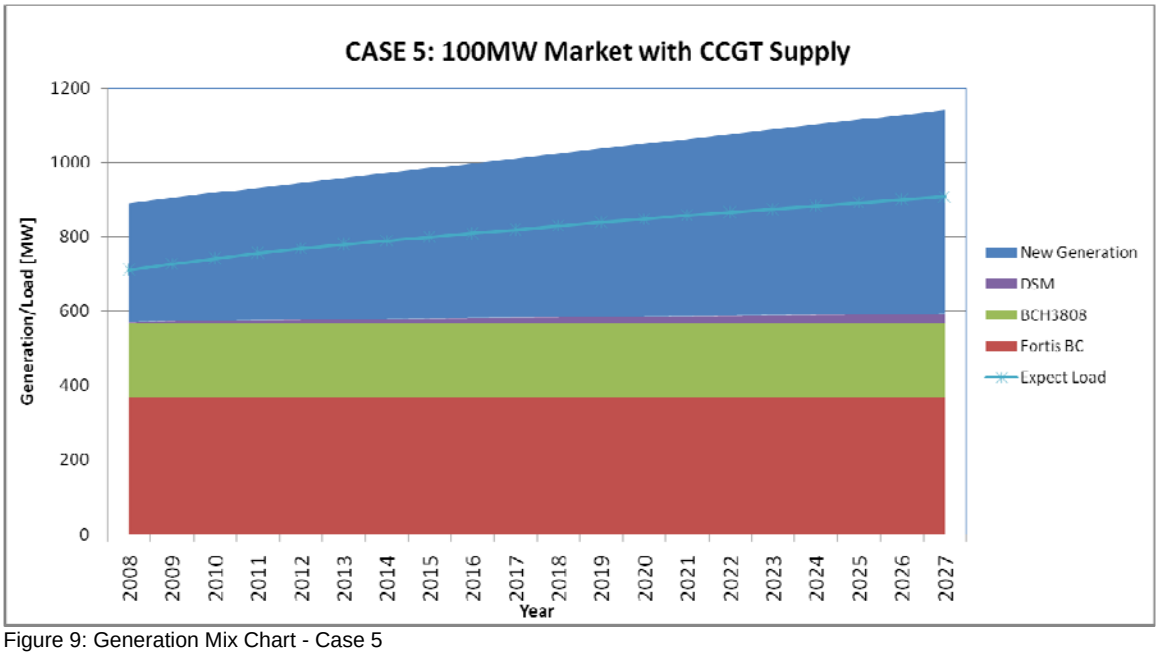

Figure 9: Generation Mix Chart - Case 5

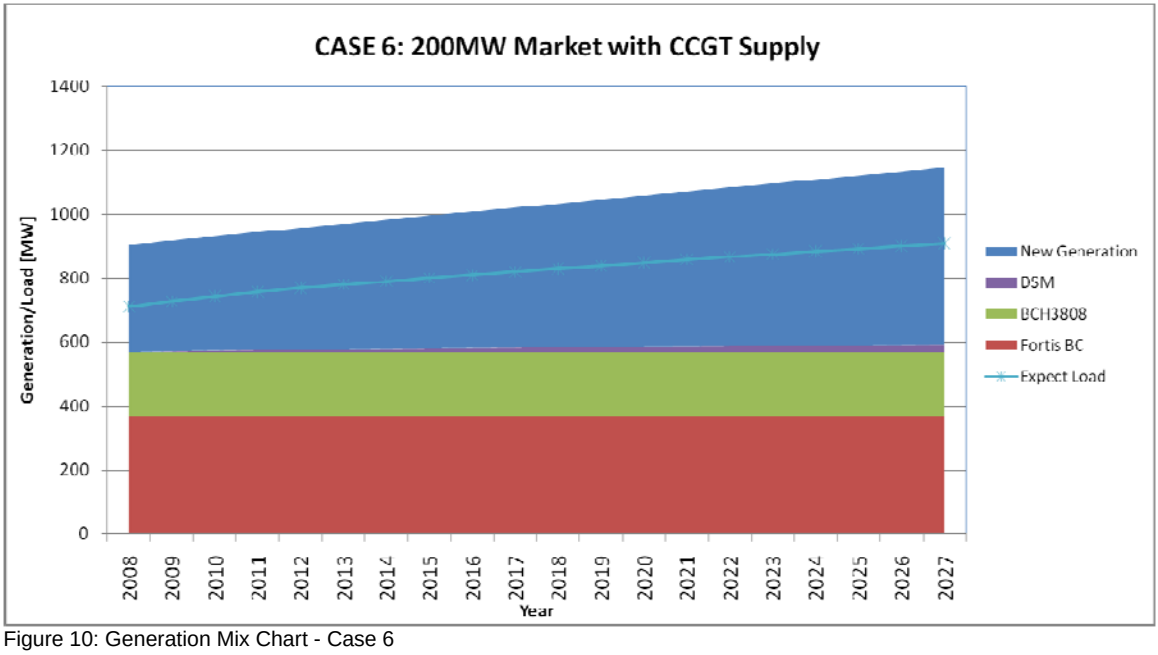

Figure 10: Generation Mix Chart - Case 6

APPENDIX C: GENERATION MIX CHARTS

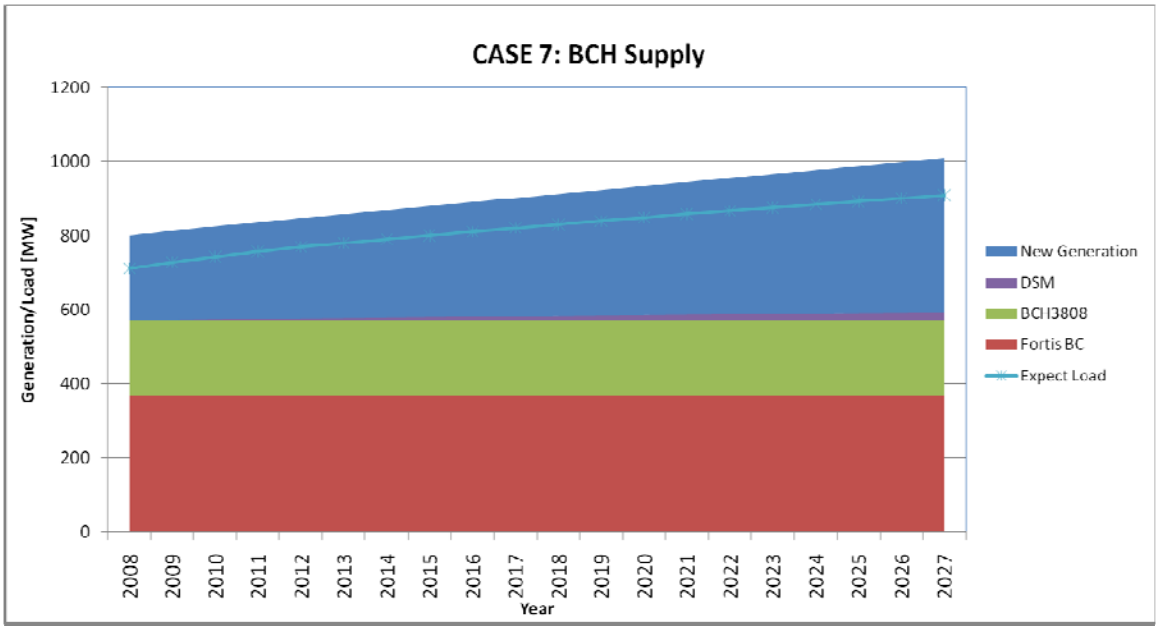

Figure 11: Generation Mix Chart - Case 7

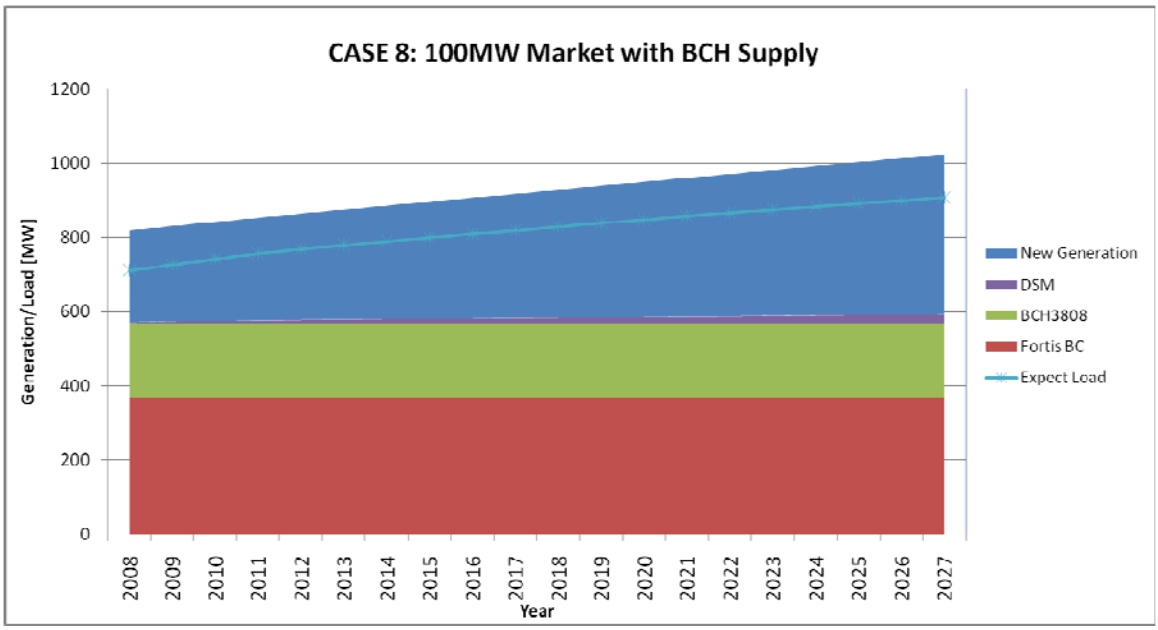

Figure 12: Generation Mix Chart - Case 8

APPENDIX C: GENERATION MIX CHARTS

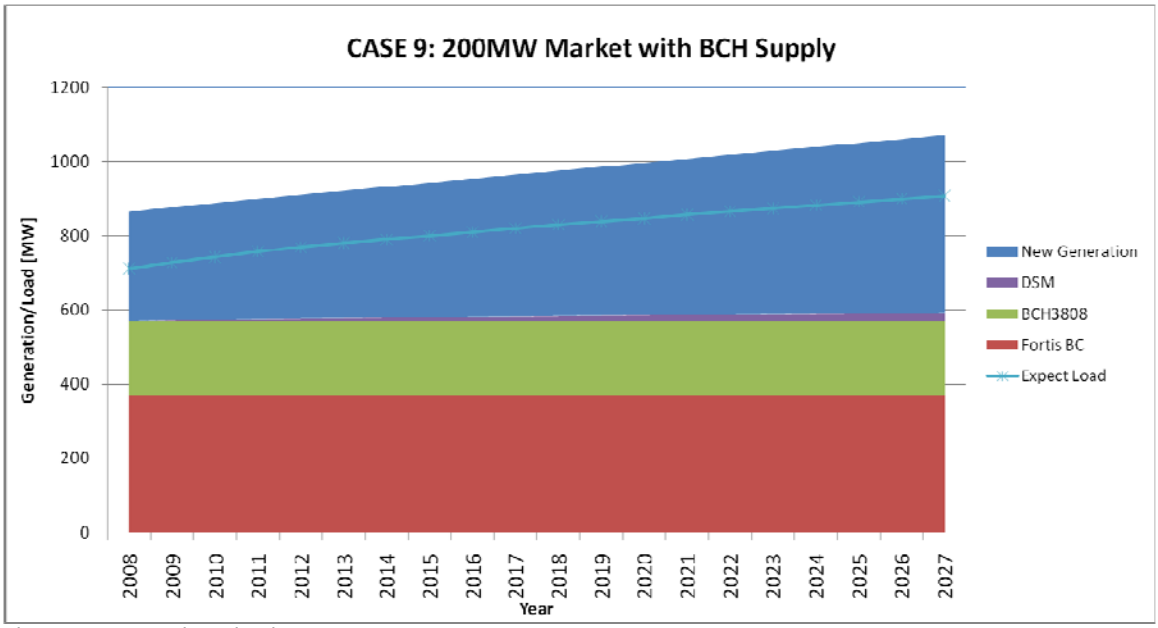

Figure 13: Generation Mix Chart - Case 9

APPENDIX D: GENERATION RESERVES WITH HLOLE

COMMON ELEMENTS			CASE 1: TCM only					
Year	Fortis BC	BCH3808	**Low**	**Margin**	**Expected**	**Margin**	**High**	**Margin**
2008	368.8	200.0	250	15.3%	251	15.3%	252	15.3%
2009	368.8	200.0						
2010	368.8	200.0						
2011	368.8	200.0						
2012	368.8	200.0	288	14.2%	306	13.7%	332	13.5%
2013	368.8	200.0						
2014	368.8	200.0						
2015	368.8	200.0						
2016	368.8	200.0						
2017	368.8	200.0	327	13.7%	365	13.9%	404	12.8%
2018	368.8	200.0						
2019	368.8	200.0						
2020	368.8	200.0						
2021	368.8	200.0						
2022	368.8	200.0	371	13.8%	409	12.9%	473	12.7%
2023	368.8	200.0						
2024	368.8	200.0						
2025	368.8	200.0						
2026	368.8	200.0						
2027	368.8	200.0	405	13.0%	455	12.7%	529	11.7%

Table 14: Case 1 HLOLE results

COMMON ELEMENTS			CASE 2: 100MW + TCM					
Year	Fortis BC	BCH3808	**Low**	**Margin**	**Expected**	**Margin**	**High**	**Margin**
2008	368.8	200.0	236	13.3%	236	13.2%	238	13.3%
2009	368.8	200.0						
2010	368.8	200.0						
2011	368.8	200.0						
2012	368.8	200.0	277	12.7%	294	12.1%	328	13.0%
2013	368.8	200.0						
2014	368.8	200.0						
2015	368.8	200.0						
2016	368.8	200.0						
2017	368.8	200.0	322	13.0%	356	12.8%	398	12.1%
2018	368.8	200.0						
2019	368.8	200.0						
2020	368.8	200.0						
2021	368.8	200.0						
2022	368.8	200.0	363	12.8%	400	11.9%	468	12.2%
2023	368.8	200.0						
2024	368.8	200.0						
2025	368.8	200.0						
2026	368.8	200.0						
2027	368.8	200.0	399	12.3%	447	11.8%	525	11.3%

Table 15: Case 2 HLOLE results

APPENDIX D: GENERATION RESERVES WITH HLOLE

COMMON ELEMENTS			CASE 3: 200 MW + TCM					
Year	Fortis BC	BCH3808	**Low**	**Margin**	**Expected**	**Margin**	**High**	**Margin**
2008	368.8	200.0	246	14.7%	238	13.4%	249	14.8%
2009	368.8	200.0						
2010	368.8	200.0						
2011	368.8	200.0						
2012	368.8	200.0	288	14.2%	305	13.6%	339	14.4%
2013	368.8	200.0						
2014	368.8	200.0						
2015	368.8	200.0						
2016	368.8	200.0						
2017	368.8	200.0	334	14.6%	359	13.1%	411	13.7%
2018	368.8	200.0						
2019	368.8	200.0						
2020	368.8	200.0						
2021	368.8	200.0						
2022	368.8	200.0	374	14.1%	405	12.4%	476	13.1%
2023	368.8	200.0						
2024	368.8	200.0						
2025	368.8	200.0						
2026	368.8	200.0						
2027	368.8	200.0	411	13.7%	454	12.6%	536	12.4%

Table 16: Case 3 HLOLE results

COMMON ELEMENTS			CASE 4: CCGT only					
Year	Fortis BC	BCH3808	**Low**	**Margin**	**Expected**	**Margin**	**High**	**Margin**
2008	368.8	200.0	255	16.0%	256	16.0%	257	16.0%
2009	368.8	200.0						
2010	368.8	200.0						
2011	368.8	200.0						
2012	368.8	200.0	304	16.3%	323	15.9%	347	15.4%
2013	368.8	200.0						
2014	368.8	200.0						
2015	368.8	200.0						
2016	368.8	200.0						
2017	368.8	200.0	342	15.6%	377	15.3%	422	14.9%
2018	368.8	200.0						
2019	368.8	200.0						
2020	368.8	200.0						
2021	368.8	200.0						
2022	368.8	200.0	382	15.1%	426	14.9%	489	14.5%
2023	368.8	200.0						
2024	368.8	200.0						
2025	368.8	200.0						
2026	368.8	200.0						
2027	368.8	200.0	422	15.0%	471	14.4%	552	14.1%

Table 17: Case 4 HLOLE results

APPENDIX D: GENERATION RESERVES WITH HLOLE

COMMON ELEMENTS			CASE 5: 100MW + CCGT					
Year	Fortis BC	BCH3808	**Low**	**Margin**	**Expected**	**Margin**	**High**	**Margin**
2008	368.8	200.0	236	13.3%	237	13.3%	238	13.3%
2009	368.8	200.0						
2010	368.8	200.0						
2011	368.8	200.0						
2012	368.8	200.0	285	13.8%	310	14.2%	334	13.8%
2013	368.8	200.0						
2014	368.8	200.0						
2015	368.8	200.0						
2016	368.8	200.0						
2017	368.8	200.0	329	13.9%	364	13.7%	414	13.9%
2018	368.8	200.0						
2019	368.8	200.0						
2020	368.8	200.0						
2021	368.8	200.0						
2022	368.8	200.0	371	13.7%	418	13.9%	481	13.6%
2023	368.8	200.0						
2024	368.8	200.0						
2025	368.8	200.0						
2026	368.8	200.0						
2027	368.8	200.0	414	14.0%	462	13.4%	545	13.3%

Table 18: Case 5 HLOLE results

COMMON ELEMENTS			CASE 6: 200 MW + CCGT					
Year	Fortis BC	BCH3808	**Low**	**Margin**	**Expected**	**Margin**	**High**	**Margin**
2008	368.8	200.0	246	14.7%	247	14.6%	248	14.7%
2009	368.8	200.0						
2010	368.8	200.0						
2011	368.8	200.0						
2012	368.8	200.0	295	15.1%	316	15.0%	346	15.3%
2013	368.8	200.0						
2014	368.8	200.0						
2015	368.8	200.0						
2016	368.8	200.0						
2017	368.8	200.0	341	15.4%	370	14.5%	417	14.3%
2018	368.8	200.0						
2019	368.8	200.0						
2020	368.8	200.0						
2021	368.8	200.0						
2022	368.8	200.0	385	15.4%	429	15.1%	484	13.9%
2023	368.8	200.0						
2024	368.8	200.0						
2025	368.8	200.0						
2026	368.8	200.0						
2027	368.8	200.0	417	14.4%	474	14.8%	552	14.1%

Table 19: Case 6 HLOLE results

APPENDIX D: GENERATION RESERVES WITH HLOLE

COMMON ELEMENTS			CASE 7: BCH only					
Year	Fortis BC	BCH3808	**Low**	**Margin**	**Expected**	**Margin**	**High**	**Margin**
2008	368.8	200.0	187	6.4%	188	6.4%	189	6.4%
2009	368.8	200.0						
2010	368.8	200.0						
2011	368.8	200.0						
2012	368.8	200.0	226	5.9%	244	5.6%	267	5.3%
2013	368.8	200.0						
2014	368.8	200.0						
2015	368.8	200.0						
2016	368.8	200.0						
2017	368.8	200.0	262	5.4%	294	5.2%	334	4.7%
2018	368.8	200.0						
2019	368.8	200.0						
2020	368.8	200.0						
2021	368.8	200.0						
2022	368.8	200.0	299	5.0%	337	4.6%	394	4.2%
2023	368.8	200.0						
2024	368.8	200.0						
2025	368.8	200.0						
2026	368.8	200.0						
2027	368.8	200.0	334	4.8%	380	4.4%	452	3.9%

Table 20: Case 7 HLOLE results

COMMON ELEMENTS			CASE 8: 100MW + BCH					
Year	Fortis BC	BCH3808	**Low**	**Margin**	**Expected**	**Margin**	**High**	**Margin**
2008	368.8	200.0	200	8.3%	201	8.2%	202	8.2%
2009	368.8	200.0						
2010	368.8	200.0						
2011	368.8	200.0						
2012	368.8	200.0	238	7.5%	256	7.2%	279	6.9%
2013	368.8	200.0						
2014	368.8	200.0						
2015	368.8	200.0						
2016	368.8	200.0						
2017	368.8	200.0	274	6.9%	305	6.6%	346	6.1%
2018	368.8	200.0						
2019	368.8	200.0						
2020	368.8	200.0						
2021	368.8	200.0						
2022	368.8	200.0	311	6.5%	350	6.1%	405	5.4%
2023	368.8	200.0						
2024	368.8	200.0						
2025	368.8	200.0						
2026	368.8	200.0						
2027	368.8	200.0	346	6.2%	391	5.6%	463	5.0%

Table 21: Case 8 HLOLE results

APPENDIX D: GENERATION RESERVES WITH HLOLE

COMMON ELEMENTS			CASE 9: 200 MW + BCH					
Year	Fortis BC	BCH3808	**Low**	**Margin**	**Expected**	**Margin**	**High**	**Margin**
2008	368.8	200.0	240	13.9%	242	14.0%	241	13.7%
2009	368.8	200.0						
2010	368.8	200.0						
2011	368.8	200.0						
2012	368.8	200.0	278	12.8%	295	12.3%	318	11.8%
2013	368.8	200.0						
2014	368.8	200.0						
2015	368.8	200.0						
2016	368.8	200.0						
2017	368.8	200.0	313	11.9%	343	11.2%	383	10.4%
2018	368.8	200.0						
2019	368.8	200.0						
2020	368.8	200.0						
2021	368.8	200.0						
2022	368.8	200.0	349	11.1%	387	10.4%	442	9.4%
2023	368.8	200.0						
2024	368.8	200.0						
2025	368.8	200.0						
2026	368.8	200.0						
2027	368.8	200.0	383	10.5%	427	9.6%	497	8.5%

Table 22: Case 9 HLOLE results

Resource Options Report

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The analysis work in this report was performed by Willis Energy Services Ltd.

FortisBC staff made some adjustments in late 2008 and early 2009 to reflect recent resource information that was available.

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1 Introduction

The purpose of this Resource Options Report is to provide background information on the different energy and capacity resource options that were considered in developing the FortisBC Resource Plan. In this report the term option refers to a type of generation alternative; for example a combined cycle gas turbine is one generation option while a wind farm is another.

A resource portfolio consists of a package of options that would be required for a Resource Plan. The Resource Options Report discusses how different Portfolios were analyzed and assessed and the reason for selecting the Preferred Resource Strategy (PRS).

2 Resource Options and Portfolios

Prior to building portfolios of potential resources for analysis, FortisBC compiled this Resource Options Report that sets out comparative technical and cost detail on a variety of potential options.

Objectives in compiling this data included:

1. Presentation in a format that minimizes unnecessary complexities,
2. The data provides a baseline of technical information sufficient to describe the potential project, and
3. The options are comparable.

FortisBC has, for the purposes of this strategic planning document, elected to:

1. Replicate much of the technical data and presentation format utilized by BC Hydro in their 2005 Integrated Electricity Plan/Long Term Acquisition Plan (IEP/LTAP), and in BC Hydro's 2008 Long Term Acquisition Plan (LTAP), updated and adjusted where appropriate.

FortisBC's resource decision objective it to define a portfolio of resource options that effectively deals with the following questions:

1. Does it provide complete coverage of FortisBC's forecast energy and capacity gaps, and provide a Planning Margin?
2. What are the environmental impacts?
3. Does it meet the objectives of the 2007 BC Energy Plan? and
4. Is it economical?

The type of resource options considered fall into the following categories:

1. Base Load - operate full-time, providing firm capacity, significant energy, and reliable support for other, intermittent, green energy options. These include:
    a. Combined Cycle Gas Turbine (CCGT)
    b. Large Hydro. A significant hydro plant capable of providing both firm capacity and significant energy.
2. Peaking Plant - operate efficiently upon 10 minutes notice to cover the peak load periods. Peaking plants can also act as Planning Margin assets. These include:
    a. Simple Cycle Gas Turbine (SCGT)
    b. Large Hydro – capacity only
    c. Pumped Storage Hydro facility (PSH)
3. Green - a variety of "green" options, including:
    a. Wind
    b. Small Hydro with Capacity
    c. Small Hydro, Run-of-River
    d. Geo-thermal
    e. Micro Co-generation
    f. Co-generation
    g. Biomass Wood-waste

While a number of other potential resource options remain, FortisBC has not included them in this report as they are either precluded from consideration (such as nuclear), are not considered commercially viable on a scale suitable for FortisBC's consideration, or are not suitable for FortisBC's market. These include coal gasification (IGCC), wave, tidal, fuel cell, and solar.

FortisBC will continue to monitor evolving resource options and include them, as appropriate, in future iterations of its resource planning process.

3 Unit Cost Calculations

In order to facilitate a comparison of the economics of different options, unit cost calculations were required. These calculations include two major components: Unit Energy Cost in $ per MWh (UEC) and Unit Capacity Cost in $ per MW (UCC).

Unit Energy Costs (UEC): Unit Energy Costs are based on the Net Present Value of the Annual Energy Costs for an option over the option's assumed life divided by the Net Present Value of Annual Energy Generated by the Option. The energy costs include capital, the fuel costs, the variable and fixed operating & maintenance costs and the GHG offset costs. The table below is an example utilizing combined cycle gas turbine information.

Unit Energy Costs – CCGT
(Based on 8% Discount)

Year Number	Capital Expenditure ($2009 Million)	Dependable Capacity (MW)	Total Energy Charge ($/MWh)	Annual Energy (GWh)	Annual Energy Costs ($2009 Million)
1	$326.40	236	$88.74	1,652	$146.59
2		236	$86.70	1,652	$143.21
3		236	$85.21	1,652	$140.75
4		236	$84.80	1,652	$140.07
5		236	$83.22	1,652	$137.46
6		236	$81.49	1,652	$134.60
7		236	$80.32	1,652	$132.67
8		236	$79.86	1,652	$131.91
9		236	$80.43	1,652	$132.86
10		236	$81.08	1,652	$133.93
11		236	$81.68	1,652	$134.93
12		236	$80.93	1,652	$133.69
13		236	$79.76	1,652	$131.75
14		236	$80.86	1,652	$133.57
15		236	$81.80	1,652	$135.13
16		236	$83.09	1,652	$137.26
17		236	$84.23	1,652	$139.13
18		236	$85.63	1,652	$141.45
19		236	$86.01	1,652	$142.07
20		236	$88.22	1,652	$145.73
21		236	$87.73	1,652	$144.91
22		236	$88.55	1,652	$146.26
23		236	$89.36	1,652	$147.62
24		236	$90.18	1,652	$148.97
25		236	$91.00	1,652	$150.32
NPV of Capital Costs ($2009 million)					$326.40
NPV of Annual Energy Costs ($2009 million)					1,480
NPV of Annual Energy (GWh)					17,633
Levelized Energy Costs ($2009/MWh)					102.43

Annualized Unit Capacity Costs (UCC): Unit Capacity Costs are based on the Net Present Value of an option's capital costs and fixed operating and maintenance costs over the life of an option divided by the Net Present Value of the capacity provided by the plant over the life of the option. The table below is an example using Combined Cycle Gas Turbine information.

Annualized Capacity Cost – CCGT
(Based on 8% Discount)

Year Number	Dependable Capacity (MW)	Capital Expenditure $2009 million	Fixed Operating & Maintenance Costs $2009 million per year
1	236	$326.4	$3.26
2	236		$3.26
3	236		$3.26
4	236		$3.26
5	236		$3.26
6	236		$3.26
7	236		$3.26
8	236		$3.26
9	236		$3.26
10	236		$3.26
11	236		$3.26
12	236		$3.26
13	236		$3.26
14	236		$3.26
15	236		$3.26
16	236		$3.26
17	236		$3.26
18	236		$3.26
19	236		$3.26
20	236		$3.26
21	236		$3.26
22	236		$3.26
23	236		$3.26
24	236		$3.26
25	236		$3.26
NPV of Fixed O & M ($2009 million)			**$34.2**
NPV of Fixed O & M and Capital Cost ($2009 million)			**$354.2**
NPV of Annual Available Capacity in MWs			**2,519.3**
Annualized Unit Capacity Cost ($2009 million per NPV of Annual Capacity in MW)			**143,569**

While these comparisons are useful, these two components are not interchangeable, and are useful only in comparing “like” resources. While UEC is useful in comparing energy resources such as a Wind resource versus a Combined Cycle Gas Turbine (CCGT) resource, and UCC is useful in comparing capacity resources such as Pumped Storage Hydro versus a Simple Cycle Gas Turbine, the differing types of resources cannot be cross-compared via UEC and UCC. For example, a capacity resource such as a Pumped Storage Hydro facility which provides reliable, firm capacity but relatively low volumes of energy would have a disproportionately high UEC when compared with a Wind resource which provides relatively high volumes of energy yet is not a firm source of capacity. It is also important to note the generic Unit Costs are only guides to comparison. When specific resources are operated to meet specific system demands their forecast Unit Costs may vary from the generic.

4 Resource Options

4.1 Combined Cycle Gas Turbine (CCGT)

Option Type: Base Load

Reference: Data based on information from BC Hydro 2008 LTAP Appendix F-1A

PROJECT DESCRIPTION Combined Cycle Gas Turbine – 250 MW

This information from BC Hydro's LTAP describes a generic Greenfield combined cycle power station located in the southern interior of B.C. The project consists of an F Class 1x1x1 Combined Cycle Gas Turbine (CCGT) configuration with nominal output of 250 MW. Combined cycle generation involves recovery of exhaust heat from a natural gas-fired turbine generator to produce steam for use in a steam turbine generator.

The project consists of the following major equipment:

- One natural gas fuelled General Electric PG7241FA packaged gas turbine generator set with dry low NOx emissions technology (DLN).
- One unfired heat recovery steam generator (HRSG) with three pressure stages and condensate heater equipped with an SCR to achieve NOx emissions not exceeding 3.5 ppm and with space for future retrofit of a CO catalyst.
- One 100 MW (nominal) reheat condensing steam turbine generator set.
- Associated auxiliary systems including cooling towers, water treatment plant and distributed control system (DCS).

TECHNICAL INFORMATION

Installed Capacity (MW)	243
Average Annual Energy (GWh/year)	1,887
Dependable Capacity (MW)	236
Firm Annual Energy (GWh/year)	1,887
Average Heat Rate (GJ/GWh)	7,350

This technical information assumes that the site is located at an elevation of 600 metres and output is based on an ambient temperature of 15°C. The installed capacity provided is net of auxiliary plant losses. Dependable capacity is 97% of this net capacity to account for 3% average degradation over the project life. Availability is assumed to be 91.3% or 8,000 hours per year. Dependable capacity estimates were based on the assumption that a firm fuel contract (transportation and commodity) would be available.

The heat rate estimate is expressed in terms of the higher heating values (HHV) for natural gas which is the basis for natural gas purchases. Over time there will be degradation in the "clean and new" heat rate of the order of 1% to 3% depending on the location of the unit, the maintenance schedule and time between turbine overhauls. The above estimate assumes the clean and new value adjusted for 1.5% average degradation over the project life.

FINANCIAL SUMMARY

Capital Costs ($000s)	$326,400.0
Fixed Operating & Maintenance Cost ($000s/year)	$3,264.0
Variable Operating & Maintenance Cost ($000s/year)	$5.52
Annualized Unit Energy Cost ($/MWh)	**$102.43**
Annualized Unit Capacity Cost ($/MW)	**$143,569**

SCHEDULE CONSIDERATION

Project Life (Years)	25
Project Lead Time (Years)	3

The capital cost is an "all-in" estimate that includes an allowance of $9.2 million for all permitting and infrastructure connection costs (e.g., transmission, gas, water supply and effluent). The capital costs also include an allowance for Selective Catalytic Reduction (SCR) equipment which will reduce the plant's NOx emissions by up to 90%.

Fixed operation and maintenance (O&M) cost estimates were based on information provided within BC Hydro's LTAP. Variable O&M costs are for the power plant only and do not include any allowance for costs associated with fuel (transport or commodity). Fuel transportation costs or gas tolls are assumed to be included in the cost of gas.

Project lead time has been estimated at three years but permitting lead time may take longer depending on site-specific issues.

GHG FOOTPRINT

Meets Eco-Logo Criteria	No
GHG Emission Factor (tonnes CO_2 equivalent/GWh)	365
Upstream GHG Emissions (Tonnes CO_2 equivalent/GWh)	Unknown

JOB CREATION

Construction	400
Permanent	40

Construction period is 20 months. Employment estimates were provided by SNC Lavalin Inc. Thermal Power Division (BC Hydro 2005 Resource Options Report).

UNCERTAINTY

Development	Medium

Social and environmental approval of large natural gas projects can depend on site location. Sites located away from populations are estimated as having medium development risk. Based on recent regulatory and public acceptance experience, the development risk for other sites could be high.

Price Uncertainty	Low

No site specific studies have been conducted; however, the capital cost for CCGT turbines is well established. Therefore, price uncertainty is judged to be low but would be subject to some variation with exchange rates and market conditions. The price uncertainty rating is based on the capital cost and does not include uncertainty in gas prices.

4.2 Simple Cycle Gas Turbine (SCGT)

Option Type: Peak Load

Reference: Data based on information from BC Hydro 2008 LTAP Appendix F-1A

PROJECT DESCRIPTION Simple Cycle Gas Turbine – 45 MW

This project describes a greenfield 45 MW (nominal) General Electric LM 6000 PD Simple Cycle Gas Turbine (SCGT). Plant designs such as this are most effective when run to meet the peak load, compared to a Combined Cycle Gas Turbine (CCGT) that would typically run constantly to meet base load energy requirements. This unit would be equipped with a dry low NOx (DLN) control system.

TECHNICAL INFORMATION

Installed Capacity (MW)	42.3
Average Annual Energy (GWh/year)	67.0
Dependable Capacity (MW)	38.2
Average Heat Rate (GJ/GWh)	9,794

The capacity provided is net of auxiliary plant losses. Installed net capacity is 42.3 MW based on ISO conditions at sea level. Dependable capacity is adjusted for 2% degradation and for ambient conditions assuming 15° C and elevation = 600 m. For thermal peaking projects, it was assumed that the maximum annual dispatch was 20% in order to estimate a firm energy value for calculation of a representative unit energy cost. Expected operation, and hence average energy, is likely to be at 5% dispatch. Firm energy estimates were based on the assumption that a firm fuel contract would be available.

The heat rate estimate is expressed in terms of the higher heating value (HHV) for natural gas which is the basis for natural gas purchases. Over time there will be degradation in the “clean and new” heat rate of the order of 1% to 3% depending on the location of the unit, the maintenance schedule, and time between turbine overhauls. Consistent annual maintenance would limit the heat rate degradation to 1-2%. The above estimate of the average heat rate assumes the clean and new value adjusted by an average degradation of 1% over the project life.

FINANCIAL SUMMARY

Capital Cost ($000s)	$43,860.0
Fixed Operating & Maintenance Cost ($000s/year)	$510.0
Variable Operating & Maintenance Cost ($000s/MWh)	$4.08
Annualized Unit Energy Cost ($/MWh)	**$123.07**
Annualized Unit Capacity Cost ($/MW)	**$115,340**

SCHEDULE CONSIDERATION

Project Life (Years)	30
Project Lead Time (Years)	2

The plant is assumed to be a greenfield project located in the B.C. southern interior. The capital cost is an “all-in” estimate including an allowance of $4 million for all permitting and infrastructure connection costs (e.g. transmission, gas, water supply and effluent). Fixed operation and maintenance costs assume unattended operation and remote supervision with periodic site inspection by operating staff. Variable operation and maintenance costs are for the power plant only and do not include fuel costs.

Unit energy costs for thermal resource options depend largely on the market price of fuel and plant usage, which varies over time. In order to provide a unit energy cost estimate for peaking, a 20% annual dispatch factor was assumed. Unit energy costs for thermal peaking plants tend to be high because dispatch is lower and heat rate is higher compared to base load combined cycle plants.

GHG FOOTPRINT

Meets Eco-Logo Criteria	No
GHG Emissions Relative to CCGT	1.37
GHG Emissions Factor (Tonnes CO_2 equivalent/GWh)	500
Upstream GHG Emissions (Tonnes CO_2 equivalent/GWh)	Unknown

JOB CREATION

Construction	40
Permanent	10

UNCERTAINTY

Development	Medium

Social and environmental approval of small natural gas projects is dependent on site location and utilization rate. Based on recent regulatory and public acceptance experience the development uncertainty is judged to be low to medium.

Price	Minimal

No site specific studies have been conducted. However, this is a proven technology with a large number of similar projects in service in North America. Information from BC Hydro's Fort Nelson facility and information received from BC Hydro's 2004 VICFT are also consistent with the information contained in the database.

4.3 Pumped Storage

Option Type: Load or Generation Shaping

Reference: Data based on information from Devine Tarbell & Associates, April 2008

PROJECT DESCRIPTION Pumped Storage – 200 MW

This project describes a Greenfield Pumped Storage facility. A Pumped Storage Hydro facility (PSH) is a method of storing and producing electricity to supply high peak demands by moving water between reservoirs at different elevations. The costs reflected below are based upon a high-level feasibility study completed for FortisBC by Devine Tarbell & Associates in April 2008. In that study they identified numerous potential sites within FortisBC service territory, of various sizes. Capital costs could be mitigated if the lower reservoir is a pre-existing substantial body of water for which the upper reservoir volume requirements would be negligible.

TECHNICAL INFORMATION

Installed Capacity (MW)	200
Average Annual Energy (GWh/year)	584
Dependable Capacity (MW)	200
Firm Energy (GWh/year)	584
Average Heat Rate (GJ/GWh)	N/A

It is not useful as a base-load facility because, taking into account evaporation losses from the exposed water surface area and conversion losses, only approximately 70% to 85% of the electrical energy used to pump the water into the elevated reservoir can be regained. For example, to produce 175 MW for 12 hours per day, total energy output would be 2.1 GWh per day, but would require between 2.4 and 3.0 GWh per day to refill the higher reservoir each night.

This would be a reliable peaking plant with almost instantaneous response to load; and therefore also very useful to balance intermittent renewable generation (such as wind), or distributed generation resources (such as individual roof-top solar facilities). The basic capacity production equation is: 1 cubic meter of volume, dropped 100 meters, gives 0.0003 MWhr of capacity.

FINANCIAL SUMMARY

Capital Cost ($000s)	$510,000.0
Fixed Operating & Maintenance Cost ($000s/year)	$8,813.0
Variable Operating & Maintenance Cost ($000s/MWh)	$0
Annualized Unit Energy Cost ($/MWh)	**$87.86**
Annualized Unit Capacity Cost ($/MW)	**$256,556**

Relative energy costs/risk is high due to the plant's operation in a peaking capacity. If it was utilized during the HLH in excess of FortisBC needs (for sale), and refilled during LLH's lower prices, then relative costs could be reduced.

SCHEDULE CONSIDERATION

Project Life (Years)	50
Project Lead Time (Years)	3

GHG FOOTPRINT

Meets Eco-Logo Criteria	Yes
GHG Emissions Factor (Tonnes CO_2 equivalent/GWh)	0
Upstream GHG Emissions (Tonnes CO_2 equivalent/GWh)	0

UNCERTAINTY

Development	Medium
Price	Minimal

No site specific studies have been conducted. However, this is a proven technology with a large number of similar projects in-service in North America, and world-wide.

4.4 Geothermal

Option Type: Green

Region: Outside FortisBC

Reference: Data based on information from BC Hydro 2006 Integrated Electricity Plan - Adjusted for Real $2009

PROJECT DESCRIPTION Future Geothermal Potential

The BC Green Energy Study identified three potential future geothermal sites that have a minimum annual energy production potential of approximately 640 GWh. General barriers to geothermal development in BC are primarily due to insufficient data about the available resources.

Costly exploration and confirmation drilling is necessary at the outset of a geothermal project to determine production characteristics and the ultimate commercial production capacity of the resource. Remote locations can also be a development barrier because of the lack of supporting infrastructure such as access roads and transmission lines. This datasheet is based upon three potential sites:
the LakeIse Hot Springs Geothermal Project; the Mount Cayley Geothermal Project; and, the Pebble Creek Geothermal Project.

Geothermal are considered "near commercial" at this time, and therefore provided for informational and future prospect purposes only.

TECHNICAL INFORMATION

Installed Capacity (MW)	85
Average Annual Energy (GWh/year)	640
Dependable Capacity (MW)	85
Firm Energy (GWh/year)	640

The rated capacities for the three potential development sites are based on a 10 MW binary plant using a high temperature hot water resource for Lakelse Hot Springs, a 20 MW single-flash plant using a moderate-temperature hot water resource for Mount Cayley, and a 55 MW double-flash plant using a high-temperature hot water resource for Pebble Creek. The Lakelse Hot Springs, Mount Cayley and Pebble Creek site may have the production capacity for up to 50 MW, 100 MW and 200 MW respectively.

SCHEDULE CONSIDERATION

Project Life (Years)	30
Project Lead Time (Years)	Unknown

GHG FOOTPRINT

Meets Eco-Logo Criteria	Yes
GHG Emission Factor (tonnes CO_2 equivalent/GWh)	0.03
Atmospheric Emissions (metric tonnes/GWh)	Nil

JOB CREATION

Construction	340
Permanent	40

Employment potential was based on estimated job creation figures calculated by Western Geopower Corp. for their proposed South Meager Geothermal Project.

UNCERTAINTY

Development	High
Price	High

Geothermal is new to BC.

ADDITIONAL REFERENCE

Triton Consultants. 2002. Green Energy Study for British Columbia - Phase 2: Mainland
Western GeoPower Corp, South Meagher Geothermal Project website: http://www.geopower.ca

4.5 Wind-FortisBC

Option Type: Green

Reference: Data based on information from BC Hydro 2006 Integrated Electricity Plan – Adjusted for Real $2009. Reliable capacity updated to 2009.

PROJECT DESCRIPTION FortisBC Territory Wind Bundle

There are a number of sites that have wind potential in FortisBC Territory. The potential projects are represented by generic 30 MW projects.

TECHNICAL INFORMATION

Installed Capacity (MW)	30
Average Annual Energy (GWh/yr)	65.7
Equivalent Dependable Capacity (MW)	7.5

The calculation of average annual energy is based on the equivalent dependable capacity rating of 25%. Other losses (including transmission losses are not included).

FINANCIAL SUMMARY

Cost to Build ($000s)	$61,586.0
Operating & Maintenance Cost ($000s/year)	$1,053.0
Annualized Unit Energy Cost ($/MWh)	**$113.55**
Annualized Unit Capacity Cost ($/MW)	**$976,811**

Capital and O&M costs are extrapolated from estimates of better known sites in the Peace Region.

SCHEDULE CONSIDERATION

Project Life (Years)	20
Project Lead Time (Years)	3

GHG FOOTPRINT

Meets Eco-Logo Criteria	Yes
GHG Emission Factor (tonnes CO_2 equivalent/GWh)	0
Atmospheric Emissions (metric tonnes/GWh)	

JOB CREATION

Construction	140
Permanent	8

UNCERTAINTY

Development	Medium

4.6 Biomass Woodwaste

Option Type: Green

Reference: Data based on information from BC Hydro 2006 Integrated Electricity Plan - Adjusted for Real $2009 and Willis Energy files

PROJECT DESCRIPTION Bundle – Biomass Woodwaste

Through various studies and calls for proposals, numerous potential wood-residue biomass projects have been identified across the province. Projects range in size from 10 MW to 80 MW. The smaller ones are associated with sawmill projects, the medium size 10 to 50 MW are generally associated with pulp mills and the large ones are stand alone biomass power projects similar to the existing 65 MW operating facility at Williams Lake. For this analysis a project totaling 80 MW was used. The total firm energy from such a project would be 640 GWh/yr

TECHNICAL INFORMATION

Installed Capacity (MW)	80
Average Annual Energy (GWh/year)	640
Dependable Capacity (MW)	80
Firm Energy (GWh/year)	640

Average Annual Energy based on 91.3% availability (8,000 hr). The installed capacity provided is net of auxiliary plant losses. Dependable capacity is 100% of this net capacity.

FINANCIAL SUMMARY

Cost to Build ($000s)	$177,539
Operating And Maintenance Cost ($000s/year)	$19,388
Annualized Unit Energy Cost ($/MWh)	**$124.98**
Annualized Unit Capacity Cost ($/MW)	**$468,385**

SCHEDULE CONSIDERATION

Project Life (Years)	20
Project Lead Time (Years)	2

GHG FOOTPRINT

Meets Eco-Logo Criteria	Yes
GHG Emission Factor (tonnes CO_2 equivalent/GWh)	0

JOB CREATION

Construction	500
Permanent	30

UNCERTAINTY

Development U	High
Price	Medium-high

There are a number of factors that will affect the price. These include the construction and O&M costs as well as the capacity factor.

4.7 Large Hydro – Capacity

Option Type: Large Hydro

Region: Outside FortisBC

Reference: Data based on information from BC Hydro 2008 LTAP Appendix F-1A

PROJECT DESCRIPTION

A Large Hydro – Capacity Only project envisions generation units utilizing pre-existing reservoirs at existing Large Hydro projects. These could include, for example, Teck's Waneta facility, Columbia Power Corporation/Columbia Basin Trust (CPC/CBT) Waneta expansion project, or any of BC Hydro's Resource Smart Resources. For project modeling purposes, BC Hydro's Mica 5 has been utilized.

The existing Mica Generating Station consists of four 450 MW generating units and empty bays for two additional units. This project describes the installation of the fifth generating unit (Mica 5) at the existing powerhouse. The dependable capacity is less than the installed capacity because of head losses in the winter period when the reservoir is drawn down. The energy associated with this unit is mainly an energy efficiency gain at Mica G.S. since this new, more efficient unit would be preferentially selected to operate ahead of the original four units. The amount of energy gain would be approximately 40 percent less if the Resource Smart project to upgrade Mica Units 1 & 2 were to proceed ahead of Mica 5. Mica Unit 5 would also provide system energy shaping benefits because it would enable BC Hydro to shift more energy generation into higher value periods. Estimates of energy efficiency gains and energy shaping benefits vary with system modeling assumptions particularly load/resource balance and HLH/LLH energy price differentials. Fixed O&M includes allowance for sustaining capital.

The rights to Mica 5 are owned by BC Hydro, however it is a BC Resource, has been well studied and could be readily developed. It is included in FortisBC' Resource Option as it easily identifies the benefits associated with this type of project.

TECHNICAL INFORMATION

Installed Capacity (MW)	500
Average Annual Energy (GWh/year)	130
Dependable Capacity (MW)	465
Firm Energy (GWh/year)	130

FINANCIAL SUMMARY

Direct Capital Cost ($000s)	$337,471
Operating And Maintenance Cost ($000s/year)	$1,000.0
Water Rentals - Capacity ($000s)	$1,889.4
Water Rentals - Energy ($000s)	$275.0
Annualized Unit Energy Cost ($/MWh)	**$236.22**
Annualized Unit Capacity Cost ($/MW)	**$66,039**

Direct Capital Cost excludes Interest during Construction (IDC) and Corporate Overhead.

SCHEDULE CONSIDERATION

Project Life (Years)	50
Project Lead Time (Years)	6

Source: as per BC Hydro 2008 LTAP.

GHG FOOTPRINT

Meets Eco-Logo Criteria	Yes
GHG Emission Factor (tonnes CO_2 equivalent/GWh)	0

JOB CREATION

Construction	315
Permanent	0

UNCERTAINTY

Development Uncertainty	Low

Projects of this type have been developed by BC Hydro. The technology is well understood.

Price	Medium

A detailed design has not been completed.

4.8 Large Hydro – Capacity and Energy

Option Type: Large Hydro

Region: Peace River
Reference: Data based on information from BC Hydro 2006 Integrated Electricity Plan, and the BC Hydro 2008 LTAP - Adjusted for $2009

PROJECT DESCRIPTION

This project envisions a new Large Hydro project with a new, substantial reservoir. Numerous sites have been identified in BC, and updates on the viability of those sites have been provided in BC Hydro's 2008 LTAP. Of the potential sites, Site C, as the location most thoroughly studied, has been selected as the example utilized in this project description.

Site C is a proposed hydroelectric generating station located on the Peace River approximately 7 km southwest of Fort St. John. The project, as currently proposed, includes an earth fill dam across the river with a spillway, power intake structure, powerhouse and switchgear facilities on the river's right bank. The current design has the powerhouse containing six units with a total rated capacity of 900 MW, which would supply approximately 4,600 GWh per year to B.C Hydro's system

With respect to FortisBC Resource Plan, the cost and characteristics of this project are useful to consider as a terms of reference.

TECHNICAL INFORMATION

Installed Capacity (MW)	912
Average Annual Energy (GWh/year)	4,600
Dependable Capacity (MW)	912
Firm Energy (GWh/year)	4,000

It is assumed that the capacity provided by large hydro electric projects with storage is 100% dependable for meeting winter peak.

FINANCIAL SUMMARY

Cost to Build ($000s)	$3,381,300.0
Operating And Maintenance Cost ($000s/year)	$4,386
Water Rentals - Capacity ($000s)	$3,615.0
Water Rentals - Energy ($000s)	$25,859.0
Annualized Unit Energy Cost ($/MWh)	**$67.00**
Annualized Unit Capacity Cost ($/MW)	**$300,804**

SCHEDULE CONSIDERATION

Project Life (Years)	70
Project Lead Time (Years)	11

Capital Cost is based on averaging the range $5 billion and $6.6 billion from BC Hydro's Peace River Site C Hydro Report, Summary: Stage 1 Review of Project Feasibility December 2007.

GHG FOOTPRINT

Meets Eco-Logo Criteria	Uncertain
GHG Emission Factor (tonnes CO_2 equivalent/GWh)	0

JOB CREATION

Construction	5,110
Permanent	25

UNCERTAINTY

Development	Medium

Projects of this type have been developed by BC Hydro. The technology is well understood.

Price	Medium

A detailed design has not been completed.

ADDITIONAL REFERENCE

BC Hydro Peace River Site C Hydro Project Feasibility Review: Stage 1 Completion Report

4.9 Small Hydro – Run of River

Option Type: Green

Reference: Data based on information from BC Hydro 2006 Integrated Electricity Plan - Adjusted for Real $2009.

PROJECT DESCRIPTION

There are a number of potential small hydro sites within FortisBC territory. Data below is generic at this time, lacking site-specific details. New "run-of-the-river" small hydro sites provide the majority of their energy during the spring freshet season - a seasonal time that does not match FortisBC's current needs. Further, given the lack of reservoir at these facilities, there is little dependable capacity. An additional fact is that there is limited potential for such sites to be located near FortisBC's primary load growth within the Okanagan, driving up potential transmission impacts/costs.

TECHNICAL INFORMATION

Installed Capacity (MW)	38
Average Annual Energy (GWh/yr)	149
Equivalent Dependable Capacity (MW)	0

The calculation assumes a 40% capacity factor.

FINANCIAL SUMMARY

Cost to Build ($000s)	
Operating And Maintenance Cost ($000s/year)	Low
Annualized Unit Energy Cost ($/MWh)	**$122**
Annualized Unit Capacity Cost ($/MW)	

SCHEDULE CONSIDERATION

Project Life (Years)	40
Project Lead Time (Years)	5

Relative costs take into consideration recent BC Hydro CFT quotes as well as transmission costs and also that a large portion of the power would not be available when Fortis needs the power.

GHG FOOTPRINT

Meets Eco-Logo Criteria	Yes
GHG Emission Factor (tonnes CO_2 equivalent/GWh)	0
Atmospheric Emissions (metric tonnes/GWh)	

JOB CREATION

Construction	TBD
Permanent	TBD

UNCERTAINTY

Development	Medium
Price	Medium-high

Small Hydro, Run-of-River projects are not considered prudent solutions for FortisBC at this time.

4.10 Small Hydro – with Capacity

Option Type: Green

Reference: Information from proposed IPP facility (Banks Energy Inc. – Info TSX Exchange Report)

PROJECT DESCRIPTION

There is the potential for small hydro projects with a storage reservoir in FortisBC's market. They would require considerable further study and engineering development. The values below are based on a project that was investigated by an Independent Power Developer in the 1992 to 2000 period, and improved to C$2009 levels based upon best estimates. More accurate data would require substantial study.

TECHNICAL INFORMATION

Installed Capacity (MW)	40.0
Dependable Capacity (MW)	37.2
Average Annual Energy (GWh/yr) (based on 44% capacity factor)	154

FINANCIAL SUMMARY

Cost to Build ($000s) based on $2500 per kW	$148,000
Operating And Maintenance Cost ($000s/year)	162
Annualized Unit Energy Cost ($/MWh)	**$87.92**
Annualized Unit Capacity Cost ($/MW)	**$337,992**

SCHEDULE CONSIDERATION

Project Life (Years)	40
Project Lead Time (Years)	3

GHG FOOTPRINT

Meets Eco-Logo Criteria	Yes
GHG Emission Factor (tonnes CO_2 equivalent/GWh)	0
Atmospheric Emissions (metric tonnes/GWh)	

JOB CREATION

Construction	TBD
Permanent	TBD

UNCERTAINTY

Development	Medium
Price	Medium-high

4.11 Micro-Cogeneration

Option Type: Base Load

Region: FortisBC
Reference: Data based on information from BC Hydro 2006 Integrated Electricity Plan - Adjusted for Real $2009

PROJECT DESCRIPTION Small Gas Cogeneration

Cogeneration is the simultaneous production of electrical and thermal energy from a single fuel. Cogeneration involves thermal power production and a steam/thermal host to use the excess heat produced from the generating process. Steam/thermal hosts for small-scale gas cogeneration can include green houses, hospitals and other institutions such as universities. By using waste heat in a process that requires heating, the efficiency of cogeneration plants is 90% or greater, compared to 50% efficiency for CCGTs. There may be potential for these projects in the FortisBC service territory.

TECHNICAL INFORMATION

Installed Capacity (MW)	25
Average Annual Energy (GWh/year)	175
Dependable Capacity (MW)	25
Firm Energy (GWh/year)	200
Average Heat Rate (GJ/GWh)	4.800

The 25 MW capacity is assumed to consist of 5 projects with 5 MW installations. Actual sizes of these projects will vary. The 25 MW installed capacity is net of auxiliary plant losses. Dependable capacity is 100% of this net capacity and availability is assumed to be 91.3% or 8,000 hours per year.

Heat rate for the purpose of electricity generation is 9,600 GJ/GWh. However, 80% of revenue generated from waste heat is assumed to be used to offset the cost of electricity generation. Therefore the equivalent heat rate for the plant is 4,800 GJ/GWh. Cogeneration plants are not as dispatchable as CCGTs as there may be times when it is not economic to run the plant for generating electricity but the plant must still be run for the steam requirement.

SCHEDULE CONSIDERATION

Project Life (Years)	25
Project Lead Time (Years)	2

GHG FOOTPRINT

Meets Eco-Logo Criteria	Uncertain
GHG Emission Factor (tonnes CO_2 equivalent/GWh)	0.61
Atmospheric Emissions (metric tonnes/GWh)	130,000

UNCERTAINTY

Development	Low

These projects have lower permitting risks than a CCGT primarily because cogeneration is a clean resource and tends to have lower emissions and land impacts than a large scale thermal project. The projects are also small and would be installed on existing sites.

Price	Low-Medium

Natural gas price represents the biggest price risk factor. These projects will likely not proceed without a tolling arrangement.

While Micro-co-generation projects have value, and will be encouraged in FortisBC's market, they do not provide utility scale solutions.

4.12 Cogeneration

Option Type: Base Load

Region: FortisBC

PROJECT DESCRIPTION

There is potential for larger scale co-generation projects. Suitable sites are ones which have a large existing thermal load. For project description purposes, Teck's Trail facility is useful as an example. Such a facility uses large amounts of natural gas for a process heating requirement. A cogeneration plant would generate electricity as a byproduct of the process heat generation requirement.

The information is not based on any site costing but reflects information from other industrial cogeneration sites, as provided by Willis Energy Services.

TECHNICAL INFORMATION

Installed Capacity (MW)	50
Average Annual Energy (GWh/year)	350
Dependable Capacity (MW)	50
Firm Energy (GWh/year)	350
Average Heat Rate (GJ/GWh)	4.800

SCHEDULE CONSIDERATION

Project Life (Years)	25
Project Lead Time (Years)	2

GHG FOOTPRINT

Meets Eco-Logo Criteria	Uncertain
GHG Emission Factor (tonnes CO_2 equivalent/GWh)	0.61
Atmospheric Emissions (metric tonnes/GWh)	260,000

UNCERTAINTY

Development	Low

These projects have lower permitting risks than a CCGT primarily because cogeneration is a clean resource and tends to have lower emissions and land impacts than a large scale thermal project. Depending upon the facility, there may also be opportunity to lower the facilities native emissions. The projects would be installed on existing sites.

Price	Low-Medium

Natural gas price represents the biggest price risk factor. These projects will likely not proceed without a tolling arrangement.

These projects represent potential utility scale solutions and will be encouraged by FortisBC.

5 Resource Options Summary

The table below is a summary of the key characteristics for the options that were examined in the development of different portfolios. It must be noted that in order to meet all of FortisBC's capacity and energy requirements for some options multiple units (e.g., SCGT or Wind), or combinations of the units presented below, were required in the portfolio development.

Summary of Resource Option Characteristics

RESOURCE OPTIONS	*Option Type*	*CAPACITY (MW)*		*Firm Energy (GWh / year)*	*GHG Emission Factor (tonnes / GWh)*
		Dependable	*Installed*		
Combined Cycle Gas Turbine	Base Load	236.0	243	1,887	365
Combined Cycle Gas Turbine	Base Load	48.5	50	294	365
Simple Cycle Gas Turbine	Peak Load	97.8	103	171	500
Simple Cycle Gas Turbine	Peak Load	38.2	42.3	67	500
Biomass Woodwaste	Green	80.0	80	640	0.0
Small Hydro with Capacity	Green	37.2	40	154	0.0
Wind	Green	7.5	30	66	0.0
Pumped Storage Hydro facility	Load or Generation Shaping	200.0	200	584	0.0

The table below is a tabulation of the Unit Energy and Capacity cost for the different options that were considered in the Portfolio analysis.

Unit Energy and Capacity Cost for Resource Options

Resource Options	Dependable Capacity (MW)	Capital Cost (2009$ millions)	Annualized Unit Energy Cost (2009$/MWh)	Annualized Unit Capacity Cost (2009$/MW/yr)
Combined Cycle Gas Turbine	236.0	326.4	102.43	143,569
Combined Cycle Gas Turbine	48.5	142.8	141.64	343,120
Simple Cycle Gas Turbine	97.8	71.4	na	72,150
Simple Cycle Gas Turbine	38.2	43.9	na	115,340
Biomass Woodwaste	80.0	177.5	124.98	na
Small Hydro with Capacity	37.2	148.9	91.75	342,032
Wind	7.5	61.6	113.55	na
Pumped Storage Hydro facility	200.0	510.0	na	256,556

The table below outlines why some of the resource options were not considered in the Portfolio analysis.

Resource Options	Reasons for Not Including in Portfolio Analysis
Coal (IGCC)	Provincial legislation requires all new coal fired projects to fully sequester the CO2 they generate. At this time sequestration technology is not developed.
Tidal	Projects are not in FortisBC market
Geothermal	Projects being investigated to date are not in FortisBC service territory and economics and technology are uncertain.
MicroCogen	Not considered system-scale for inclusion in Resource Planning. FortisBC will continue to consider opportunities as they arise.
Cogeneration	Insufficient site-specific technical information available.

Economic Running Of Simple Cycle Gas Turbine (SCGT)

Submitted to

FORTISBC

By

Paul Willis

Willis ENERGY SERVICES LTD.

September 25, 2008

Economic Running of SCGT

Introduction

The purpose of this analysis is to determine whether FortisBC should increase the run time of the proposed three Simple Cycle Gas Turbine (SCGT) units to achieve economic benefits. The Resource Plan model runs indicate the amount of time that the SCGTs will need to be operated to meet system capacity needs starting in 2012. The units could be operated in addition to these times for economic benefit. The economic benefit arising when the fuel and variable operating and maintenance costs are less than the revenue that could be obtained from selling the electricity generated by the units.

In order to determine this additional run time, this analysis investigated the Pacific Northwest electricity and natural gas markets and used the Resource Plan model to calculate the number of economic run hours.

As a reference, the historic operating times for BC Hydro's Burrard Thermal Plant were reviewed. BC Hydro does operate this plant for capacity and economic dispatch reasons. The fuel to electricity efficiency for Burrard is approximately the same as a SCGT plant and therefore its historic run times provide information as to the amount of time that a plant with this efficiency would be operated for economic dispatch reasons.

Conclusions

This analysis indicated that SCGT generating units are most suited to operate for capacity reasons in today's energy market. The calculated economic run times were essentially the same as the times when the units would be operated for capacity reasons. Accordingly it was concluded that from a revenue projection perspective, assuming a long-term economic benefit from economic dispatch of the SCGT units could not be justified. Over the planning period there will probably be times when the units could be operated for short periods of time for economic dispatch reasons. However, it is not feasible to estimate the amount of time that this would occur and it is probable that it will be for a small percentage of the time.

Pacific Northwest Market

In the Pacific Northwest, Mid Columbia (Mid-C) and Sumas are the two most important trading hubs for electricity and natural gas respectively. This analysis employed the historical hourly electricity prices at the Mid-C hub and daily natural gas prices at the Sumas hub. The Mid-C hourly price forecast included estimates for super peak, on peak, and off peak periods. The Sumas daily natural gas price forecast was used.

Cost of SCGT generation

There are five main factors used to determine the estimated daily SCGT fuel and variable operation cost:

1. Sumas daily natural gas: US$/MMBtu
2. Daily exchange rate from Bank of Canada: US$ to C$
3. Conversion factor from MMBtu to GJ: 0.947
4. An average heat rate of a SCGT: 9,794 GJ/GWh
5. Estimated natural gas transportation cost: C$0.75 per GJ

The following table compares the hourly Mid-C prices from 2005 to 2007 with the estimated SCGT generation cost based on the above five factors. The comparisons show the number of High Load Hours (HLH) and Low Load Hours (LLH) in each month and calculates the percentage of run time over the maximum available run time.

For all the three years (2005-2007), the annual average run time was estimated to be 6.8%. In 2007, the highest of all three years, the annual average run time was estimated to be 7.9%.

Economic Running of SCGT

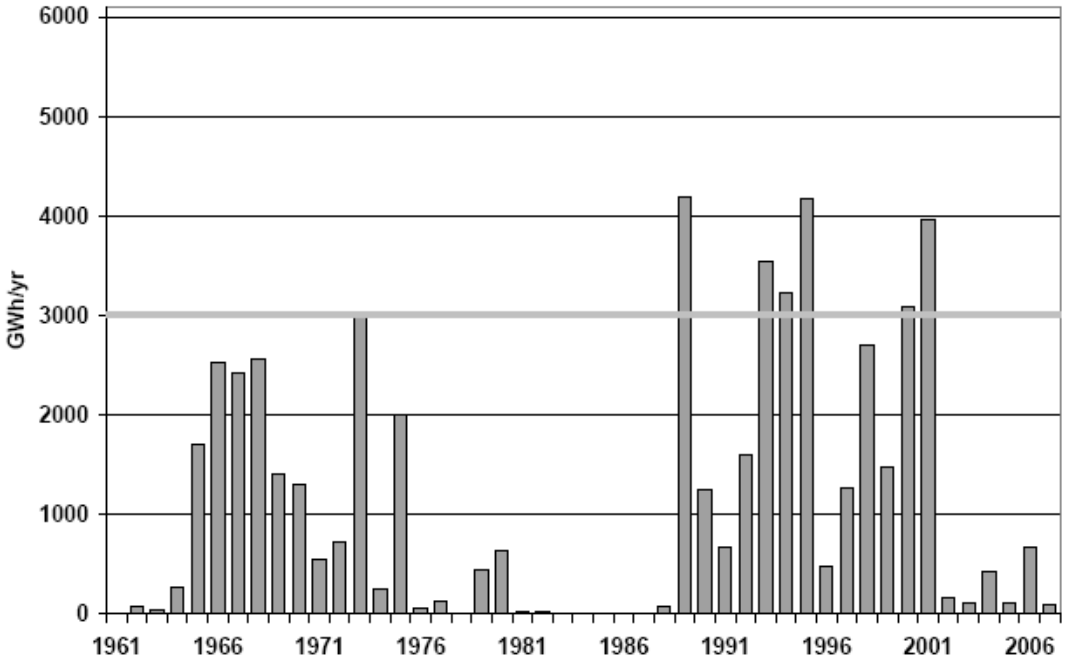
Hours that Mid-C Prices were Greater than SCGT Fuel and Variable O&MCosts (Reference Sumas Daily Gas Prices) 2005 – 2007

Month	No. of Days	Total Hours Avail.	No. of Hours Mid-C price above SCGT Fuel & Variable Operation Cost			No. of Hours Mid-C HLH price above SCGT Fuel & Variable Operation Cost			No. of Hours Mid-C LLH prices were above SCGT Fuel & Variable Operation Cost			Total Percent		
			'05	'06	'07	'05	'06	'07	'05	'06	'07	'05	'06	'07
Jan	31	744	16	0	39	16	0	39	0	0	0	2.2%	0.0%	5.2%
Feb	28	672	0	0	0	03	0	0	0	0	0	0.0%	0.0%	0.0%
Mar	31	744	0	0	3	0	0	3	0	0	0	0.0%	0.0%	0.4%
Apr	30	720	0	6	36	0	6	34	0	0	2	0.0%	0.8%	5.0%
May	31	744	9	42	5	9	42	5	0	0	0	1.2%	5.6%	0.7%
Jun	30	720	10	50	41	10	48	41	0	2	0	1.4%	6.9%	5.7%
Jul	31	744	35	237	101	32	193	100	3	44	1	4.7%	31.9%	13.6%
Aug	31	744	36	74	254	36	74	247	0	0	7	4.8%	9.9%	34.1%
Sep	30	720	6	138	142	6	133	136	0	5	6	0.8%	19.2%	19.7%
Oct	31	744	5	112	9	5	111	9	0	1	0	0.7%	15.1%	1.2%
Nov	30	720	25	14	19	24	13	18	1	1	1	3.5%	1.9%	2.6%
Dec	31	744	133	2	42	115	2	41	18	0	1	17.9%	0.3%	5.6%
Total	**365**	**8,760**	**275**	**675**	**691**	**253**	**622**	**673**	**22**	**53**	**18**	**3.1%**	**7.7%**	**7.9%**

BC Hydro Burrard

Burrard is a six unit, 900 MW natural gas-fired generating plant located on Burrard Inlet near Port Moody. During the 1960s, Burrard operated as a base load plant, but following completion of major new hydro plants on the Peace and Columbia Rivers in the late 1960s and early 1970s, the operation changed to that of a swing plant. That is, the operation varies in response to available energy from the major hydroelectric plants, gas prices, and external market conditions. The following chart was obtained from BC Hydro's 2008 Long Term Acquisition Plan (LTAP). From 2001 to 2006, Burrard did not generate more than 1,000 GWh. The six years' average run time was about 8.6%.

Burrard Actual Annual Generation[1]



FortisBC Resource Planning Model

In the FortisBC Resource Planning model, the annual average run time for capacity reasons from 2012 to 2015 was 8.3%, with 8.9% in 2015. Detailed numbers are show in the following table.

Model Calculations of SCGT Operation

Year	SCGT Operation
2012	7.8%
2013	8.0%
2014	8.5%
2015	8.9%
Average	**8.3%**

[1] Source: BC Hydro 2008 Long Term Acquisition Plan, Figure 5-7.

1 TRANSMISSION REQUIRED FOR NEW RESOURCES

1.1 Introduction

Without knowing either site locations or final resource specifications it is impossible for FortisBC to estimate transmission costs – economic or environmental. Specific costs will be developed via the work recommended in the Action Plan for the Preferred Resource Strategy.

However, there will be a cost associated with delivering the energy from the point of production to the point of consumption within the FortisBC system, and it is important to understand, at least in general terms, what inputs will have to be considered.

Some resource portfolio options may include adding generation within the BCTC system. This overall cost can be divided as follows:

a) Transmission infrastructure additions/upgrades within the BCTC system (directly funded by FortisBC) to deliver the energy to the Okanagan and Kootenay points-of-interconnection,
b) Transmission infrastructure additions/upgrades within the BCTC system (funded through BCTC rates) to deliver the energy to the Okanagan and Kootenay points-of-interconnection, and;
c) Transmission infrastructure additions/upgrades within the FortisBC system to deliver the energy to the end users.

1.2 BCTC Transmission System Upgrades

FortisBC has previously negotiated a General Wheeling Agreement (GWA) with BCTC which allows the company to take advantage of the provincial 500-kV transmission grid to wheel power from the Kootenay generation region to the Okanagan load centre. The maximum wheeling capacity under the current agreement is set at 600 MW; however, the actual nomination may be lower if the full transfer capacity is not required. Table 1 shows the FortisBC nominations for wheeling to the Okanagan Interconnection through to September 2013 (nominations must be made five years in advance).

Table 1 – FortisBC GWA Nomination

	Year	Nominated Wheeling Demand (MW)	Wheeling cap as per GWA (MW)
1	2008/2009	175	230
2	2009/2010	180	264
3	2010/2011	180	298
4	2011/2012	200	332
5	2012/2013	225	366
6	2013/2014	†	400
7	2014+	†	600

Note: Year starts October 1 and ends September 30.
† - Not yet determined

For subsequent years, FortisBC could take full advantage of its rights under the GWA which could provide up to 600 MW of firm transfer capacity to the Okanagan area. BCTC has already modeled these transfers as "Committed Use" in determining the Available Transfer Capacity in their system[1]. Thus, as long as future transfers remain within the 600 MW limit, it is not expected that any major upgrades would be required to the BCTC system. However, BCTC has stated that the in-service dates of previously identified capital projects (such as additional 500 kV line series compensation) could be affected depending on the location, amount and seasonal characteristics of new resources[2]. Further studies and discussions would be required between FortisBC and BCTC to determine the impacts of any new resource additions.

If BCTC system reinforcements beyond those already identified are required, they may be very costly and involve additional 500 kV or 230 kV transmission lines and/or station upgrades. In the case of 230 kV upgrades, the costs would typically be in the range of $100 million to $300 million, depending on the number and length of lines involved. If significant 500 kV additions were required, the costs would begin at approximately $500 million and escalate from there. More modest transmission capacity increases could be accommodated by the installation of series capacitors in existing 500 kV lines (as currently proposed in the BCTC Transmission System Capital Plan). These capacitor installations typically cost between $75 and $100 million.

Due to the nature of these bulk system upgrades it is probable that they would add more transmission capacity than would be strictly required for FortisBC wheeling purposes. The total BCTC capital costs would be apportioned as Direct Assignment costs to FortisBC (costs for facilities or portions of facilities that are constructed by BCTC for the sole use of FortisBC), and Network Upgrade costs (modifications or additions to transmission-related facilities that are integrated with and support BCTC's over-all transmission system) which would be included in the BCTC rate base. The relative cost allocations for any upgrade projects would need to be negotiated between FortisBC and other parties (BCTC, BC Hydro, etc.) and approved by the Commission.

In addition to any capital cost, transfers under the GWA are subject to annual capacity charges which, as of October 2008, are $19,941.03 per MW nominated wheeling demand per year. This charge is escalated by the Statistics Canada BC Consumer Price Index annual rate of inflation for July of the calendar year in which the rate adjustment is made. Based on the current 175 MW nomination, the annual wheeling cost is approximately $3.5 million. If the full GWA capacity was taken, this cost would increase to approximately $12 million annually (not including costs of inflation).

[1] Refer to BC Transmission Corporation F2010 and F2011 Transmission System Capital Plan – response to BCUC IR2 Q1.28.1

[2] Refer to BC Transmission Corporation F2010 and F2011 Transmission System Capital Plan – response to BCUC IR2 Q2.28.1

1.3 FortisBC Transmission System Upgrades

As discussed previously, the required upgrades to the FortisBC transmission system would depend on the location of any new resources. Given that the majority of the FortisBC load is the Okanagan region, transmission costs would be minimized by locating new generation in this area. Following is a relative ranking of resource locations in terms of minimizing overall transmission infrastructure costs.

Table 2: New Resource Related Transmission

Ranking 1 = Least Cost, 7 = Most Cost	**Location of New Resource and Description of Interconnection**
1	North Okanagan – interconnect to Kelowna 138 kV system
2	North Okanagan – interconnect to FortisBC 230 kV system
3	South Okanagan – interconnect to FortisBC 230 kV
4	Similkameen – interconnect to FortisBC 138 kV system
5	Thompson/Okanagan – interconnect to BCTC 230 kV system
5	West Kootenay – interconnect to FortisBC 230 kV system
6	Kootenays – interconnect to BCTC 230 kV system
7	Remainder of province – interconnect to BCTC 500/230 kV system

1.4 Interconnection Costs

The interconnection costs required to integrate new generation sources into the system can be divided into two main categories:

- Station costs – the work required to either construct a new substation or modify an existing station to accept a new incoming transmission line
- Transmission costs – the work required to construct a new transmission line from the generation site to the FortisBC interconnection point

Of these two categories, the station costs are relatively fixed and depend primarily on the interconnection voltage level and whether a new substation site is required or not. Typical interconnection costs range from $1 to 3 million for a 63 kV transmission line termination, to $3 to $10 million for a 230 kV line termination.

The cost of new transmission line infrastructure depends primarily on five major factors:

- Line length;
- Operating voltage level;
- Right-of-way and/or land acquisition costs;
- Unusual construction conditions (i.e. urban environment, high elevation, mountainous terrain, etc.)

- Environmental/permitting costs.

Line construction costs range from $350,000 to $750,000 per km for typical 63 kV, 138 kV or 230 kV single circuit construction.

Note that the above estimates assume that no other significant upgrades or modifications are required to the existing system to accept the new generation resource.

For reference purposes, following are the costs for recently approved or proposed major transmission upgrade projects:

Table 3: Reference - Major Transmission Projects

Utility	Project	Project Summary	Estimated Capital Cost
FortisBC	Okanagan Transmission Reinforcement (OTR)	Construction of approximately 40 km of new single and double-circuit 230 kV lines, one new substation and related station upgrades.	$141 million
BCTC	Vancouver Island Transmission Reinforcement (VITR)	Construction of approximately 70 km of new 230 kV single-circuit overhead line/submarine cable and related station upgrades.	$245 million
BCTC	Interior to Lower Mainland Transmission Project (ILM)	Construction of approximately 250 km of new 500 kV single-circuit line and related station upgrades.	$600 million
BCTC	Central Vancouver Island Project (CVI)	Construction of approximately 12 km of new double-circuit 230 kV line, one new substation and related station upgrades.	$89 million
BCTC	5L71/5L72 Series Compensation Project	Construction of a 500 kV series capacitor station on 5L71 and 5L72 and related station upgrades (proposed project).	$65 million