CANADIAN ACADEMY OF ENGINEERING

REPORT OF THE CANADA POWER GRID TASK FORCE

VOLUME II
BACKGROUND AND ASSESSMENT

ELECTRICITY: INTERCONNECTING CANADA – A STRATEGIC ADVANTAGE

GREEN PAPER

Canadian Academy of Engineering

Electricity: Interconnecting Canada
A Strategic Advantage

Report of the Canada Power Grid Task Force
Volume II – Background and Assessment

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Preface

This is Volume II of the Report of the Canada Power Grid Task Force and was prepared by the members of the CAE Task Force, and Associates, as *Background and Assessment* to the report ‘Electricity: Interconnecting Canada – A Strategic Advantage’. The topics range from the current status of the electrical industry in Canada, planned new transmission interconnections, and some of the key technological drivers and shapers of the industry. It is comprised of the submitted documents with minimum editing.

Annex to Report:

Electricity: Interconnecting Canada A Strategic Advantage

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1. OVERVIEW OF THE ELECTRICITY INDUSTRY IN CANADA

1.1 OVERVIEW

Under the current Canadian constitution each province (or territory) is responsible for the electricity industry within its borders. Many of the provinces have established provincial power authorities (utilities) with economic development mandates. The electricity sector has tended to develop independently and self sufficiently in each province based largely on available resources and geographical features. The federal government, through the National Energy Board (NEB) has limited responsibilities for electricity sector. Specifically, the NEB regulates power exports to the United States and the construction and operation of international and designated inter-provincial transmission lines.

The Canadian electricity industry was traditionally made up of integrated power utilities encompassing all functions from power generation to power delivery to consumers, although this is now changing in several jurisdictions. In many cases the integrated power utilities are increasingly functionally unbundled to accommodate wholesale competition. In most provinces the total number of independent power producers (IPPs) is emerging.

Most of the Canadian electricity industry remains in public ownership. Provincial Crown Corporations still dominate the generation and transmission components of the industry.

This section provides a summary of the electricity generation and consumption for the nation and each of the provinces or territories.

1.2 THE NATION'S ELECTRICITY GENERATION AND CONSUMPTION

In 2007, the total electricity generation in Canada amounted to 617,470 GWh and the nation consumed 592,161 GWh of electricity [1]. The difference between the two numbers is the net export to the USA, i.e. 25,309 GWh. The generation technologies used in Canada include hydro turbine, coal or other fuel fired steam turbine, nuclear fueled turbine, simple cycle and combined cycle gas turbine, internal combustion engine, wind and tidal turbine, solar photovoltaic, etc. It is expected that more electricity would be produced by wind turbine, solar photovoltaic and biomass in the future.

The table below shows the electricity generation and consumption in GWh by province or territory in 2007[1], which are also graphically presented in Figure 1-1 for all 10 provinces. The information for the three territories is not presented in this figure as they are relatively small.

[1] Electric Power Generation, Transmission and Distribution – 2007, Statistics Canada

Province	Generation	Consumption
Newfoundland & Labrador	41,582	11,505
Prince Edward Island	45	1,206
Nova Scotia	12,575	12,860
New Brunswick	17,639	16,410
Quebec	191,962	210,014
Ontario	158,234	153,425
Manitoba	34,403	22,235
Saskatchewan	20,574	20,578
Alberta	67,432	68,073
British Columbia	71,834	74,665
Yukon	355	355
Northwest Territories	686	686
Nunavut	149	149
Total	**617,470**	**592,161**

It could be observed from the table above and Figure 1-1 that most provinces are almost self sufficient. Newfoundland & Labrador and Quebec have a long term power purchase contract that sets up the terms and conditions for sale of power produced by the Churchill Falls hydro station to Quebec. Prince Edward Island purchased more than 95% of its electricity from other jurisdictions through the New Brunswick grid.

Table 1-1 presents detailed 2007 electricity generation in Canada by province or territory and by generation technology[1]. In order to show the impact of electricity generation on greenhouse gases (GHG) emissions, the employed generation technologies are simply divided into two groups, Low GHG Emitting and GHG Emitting. The former includes hydro, nuclear, wind and tidal, solar photovoltaic while the later covers the rest technologies including coal or other fuel fired steam turbine, combustion turbine and internal combustion engine. To illustrate intuitively the electricity generation from the two groups, the results presented for all 10 provinces in Table 1-1 are graphically shown in Figure 1-2 and Figure 1-3. The numbers shown in Figure 1-3 are in percentage.

It could be seen from Table 1-1, Figure 1-2 and Figure 1-3 that in 2007, about 75% of the nation's electricity was produced by the "Low GHG Emitting" generation technologies. Four provinces, Alberta, Nova Scotia, Saskatchewan and New Brunswick were heavily dependent on the "GHG Emitting" generation technologies. Alberta had more than 95% of its electricity produced by the "GHG Emitting" generation technologies. Four provinces produced only about 10% or less of its electricity using the "GHG Emitting" generation technologies. They are Manitoba, Quebec, Newfoundland & Labrador and British Columbia. As the electricity consumption in Prince Edward Island is some 27 times of its domestic generation, the province is not considered as the one with a small percentage of electricity generated by the "GHG Emitting" generation technologies.

The installed capacity by province or territory and by generation technologies is presented in Table 1-2 and Figure 1-4. It could be seen from this table that as of December 2007, the nation had a total installed generating capacity of 124,241 MW, among which 73,437 MW was from hydro and 13,345 MW was from nuclear. Among the provinces and territories, Quebec had the largest amount of installed capacity of more than 41,000 MW, approximately one third of the nation's total installation. Ontario was ranked second with a total installed capacity of more than 32,000 MW.

The table below presents the GHG Emitting steam driven generating capacity under three age categories by province, which is based on the information presented in Electric Power Generating Stations, 2006[2]. The fuels used by the generating units listed in this table include Canadian bituminous coal, imported bituminous coal, subbituminous coal, lignite, petcoke, orimulsion, heavy fuel oil (HFO) and natural gas. The three age categories are (a) under 15 years, (b) from 15 to 30 years and (c) over 30 years. The total GHG Emitting steam driven generating capacity amounted to 25,446 MW and 16,639 MW was over 30 years old.

	GHG Emitting Steam Driven Capacity (MW)			
Province	**< 15 Years**	**15 – 30 Years**	**> 30 Years**	**Total**
Newfoundland & Labrador			490	**490**
Prince Edward Island			65	**65**
Nova Scotia		971	649	**1,620**
New Brunswick	100	639	1,283	**2,022**
Quebec	237		660	**897**
Ontario	610	761	8,045	**9,416**
Manitoba			98	**98**
Saskatchewan	165	946	1,102	**2,213**
Alberta	1,614	2,610	3,284	**7,508**
British Columbia	154		963	**1,117**
Total	**2,880**	**5,927**	**16,639**	**25,446**

1.3 LOAD DIVERSITY

Winter/Summer Peak Demand

The table below shows the annual peak power demand occurrence season in 2008 for all 10 Canadian provinces. Except Ontario encountered its annual peak demand during a summer month, all other nine provinces experienced its annual peak demand during winter months. A national power grid could provide a certain level of benefits to the provincial electric systems encountering peak demand at different times.

[2] Electric Power Generating Stations, Statistics Canada, 2006

Province	Season of Peak Demand
Newfoundland & Labrador	Winter
Prince Edward Island	Winter
Nova Scotia	Winter
New Brunswick	Winter
Quebec	Winter
Ontario	Summer
Manitoba	Winter
Saskatchewan	Winter
Alberta	Winter
British Columbia	Winter

Time Zones and Daily Load Pattern

Canada uses six primary time zones. From east to west they are Newfoundland Time Zone, Atlantic Time Zone, Eastern Time Zone, Central Time Zone, Mountain Time Zone, and the Pacific Time Zone. The following lists the main electric systems/areas/regions covered by each of the six time zones (only the provinces are listed):

1. Newfoundland Time Zone – Newfoundland island
2. Atlantic Time Zone – Labrador, Prince Edward Island, Nova Scotia and New Brunswick
3. Eastern Time Zone – Quebec and Ontario
4. Central Time Zone – Manitoba and Saskatchewan
5. Mountain Time Zone – Alberta
6. Pacific Time Zone – British Columbia

To overview the daily load variation, two days, i.e. February 13 (Wednesday) and 14 (Thursday) of 2008 were randomly selected. The hourly load demands over the two days were collected from main utilities or system operators for seven provinces (except for P.E.I, New Brunswick and Manitoba, which are not available at the time of the report preparation). The provincial hourly loads were aligned in time by taking into account the time zone to which each province belongs.

Figure 1-5 shows the actual provincial hourly load variations in MW over a period of 24 hours. The first hour in the figure corresponds to the first hour in the Newfoundland Time Zone. It was assumed that the time in the Newfoundland Time Zone is one hour ahead of that in the Atlantic Time Zone although the actual difference is only a half hour.

Figure 1-6 shows the normalized hourly load patterns.

It could be seen from Figure 1-5 and Figure 1-6 that for the two largest electric systems, Quebec and Ontario, one had its daily peak in the morning while the other in the evening. The daily peak for the nation occurred in the evening. It could also be seen that the Quebec system had two peaks over the 24 hour period.

1.4 NEWFOUNDLAND

Newfoundland and Labrador Hydro (NLH), a division of the Provincial Corporation NALCOR ENERGY, is the primary power generator for power used in Newfoundland island with an installed capacity of 1,635 MW. NLH is also involved in transmission and distribution. NALCOR ENERGY also has separate business lines for Churchill Falls Generating Station and the Lower Churchill Project. Churchill Falls Generating Station in Labrador has a rated capacity of 5,428 MW and most of the electricity it produces is sold to Hydro-Québec through a long-term power purchase contract. The Lower Churchill Project is still in the development stage and is expected to have a total capacity of over 3,000 MW.

Newfoundland Power, a subsidiary of Fortis (a publically-traded company) operates generation, transmission and distribution on the island of Newfoundland. It purchases the vast majority of its electricity from NLH and generates the rest itself. Its installed capacity in 2008 was 140 MW. Newfoundland Power serves roughly 85% of power customers in Newfoundland island, but does not serve customers in the northern peninsula or centre-south of the island nor in Labrador. Those areas are served directly by NLH.

The Island Interconnected System is currently isolated from other jurisdictions. Any power consumed on the island must be produced on the island. It has lines running at 69, 138 and 230 kV. The transmission system in Labrador is connected to Quebec. Most electricity generated by the Churchill Falls generating station was transmitted to Quebec through this interconnection.

As of December 2007, the total installed generating capacity in the province was 7,353 MW, of which the vast majority was from hydro. In 2007, the province produced 40,048 GWh of electricity while only 11,505 GWh was consumed by the province.

In its 2009 capital budget application[3], NLH predicted that its annual peak would be increased to approximately 1,760 MW by 2020 from the 2008 forecast peak of some 1,560 MW and annual electricity consumption would be increased to some 9,200 GWh from some 8,100 GWh in 2008. The Company prepared generation expansion scenarios and transmission reinforcement plan to meet the expected medium and long term power requirements.

Newfoundland Power filed its 2009 capital budget application on July 11, 2008[4]. This application included 2009 Capital Plan, which provided an overview of the Company's 2009 capital budget together with an outlook for capital expenditure through 2013.

Figure 1-7 and Figure 1-8 shows the net generating capacity installed in the province for domestic use, which were based on the NHL's 2009 capital budget application.

[3] Newfoundland and Labrador Hydro 2009 Capital Budget Application, August 2008.
[4] Newfoundland Power's 2009 Capital Budget Application, July 11, 2008.

1.5 PRINCE EDWARD ISLAND

Maritime Electric, a subsidiary of Fortis Inc. supplies electricity to customers across Prince Edward Island (PEI). This electricity is mainly purchased from off-Island sources and supplied via two submarine transmission cables owned by the Province under the Northumberland Strait. The Company owns and operates transmission, distribution and most generation facilities on the island.

Maritime Electric has an Open Access Transmission Tariff (OATT) in place. As of December 2007, PEI's total installed generating capacity was 201 MW. Over 70% is thermal power and the remainder is wind power. However the thermal power is normally operated in backup mode and is only used when there is an interruption of imported power or under peak load conditions. As a result, only 11% of the electricity generated in PEI in 2007 was from thermal plants. Maritime Electric is required by the provincial government to have 30% of its energy sales sourced from on-island wind farms by 2013.

In 2007, the Island consumed a total of 1,206 GWh of electricity while only produced 45 GWh using its own generating faculties.

Prince Edward Island has a goal of achieving 500 MW of wind power capacity by 2013, which could allow the Island to export power.

1.6 NOVA SCOTIA

Nova Scotia recently opened its electricity wholesale market for competition. The main electricity provider is Nova Scotia Power Inc. (NSPI), which provides over 95% of electricity generation, transmission and distribution in the province. It is an operating subsidiary of Emera Inc., a public entity traded on the TSX. The Nova Scotia Power System Operator (NSPSO) is responsible for operation of the supply system and administration of the wholesale power market. The NSPSO functions independently from other Nova Scotia Power operations.

As of December 2007, the province has a total installed generating capacity of 2,463 MW. In 2007, the province produced an amount of 12,574 GWh of electricity and consumed 12,860 GWh. Over 80% of the generation was from thermal power stations.

Nova Scotia Power's Integrated Resource Plan predicts that the load will increase to 15,028 GWh in 2015, an average annual growth rate of 2%. Hourly peak demand is predicted to increase to 2639 MW in 2015, which is an average annual growth rate of 2.1%.

The 10 Year System Outlook prepared by NSPI in June 2008 predicted that electrical energy demand would increase from 12,338 GWh in 2005 to 15,028 GWh by 2015, which represents an annual energy growth rate of 2% over the period.[5] The load forecast for the hour peak demand showed an increase from 2,143 MW in 2005 to 2,639 MW by 2015, which represents a growth rate of 2.1% per year. These numbers are exclusive of any Demand Side Management (DSM) program effects. The Outlook also presents addition/retirement plans of generation (including renewable power generation and DSM) and transmission resources to meet the growing load demands.

According to the NSPI's 10 Year System Outlook, Figure 1-9 and Figure 1-10 present its firm generating capacity development over the next 10 years.

[5] 10 Year System Outlook, Nova Scotia Power Inc., June 2008

1.7 NEW BRUNSWICK

NB Power, a crown corporation, is the major electric utility in New Brunswick, which has three divisions responsible for power generation, transmission and distribution.

The New Brunswick System Operator (NBSO) was created in 2004 and is responsible for the adequacy and reliability of the electricity system. The NBSO also controls the grid and operates the electricity wholesale market, while NB Power Transmission physically operates and

maintains the transmission system. The NBSO is the Reliability Coordinator for New Brunswick, PEI, Nova Scotia and northeastern Maine.

The province of New Brunswick had a total installed generating capacity of 4,535 MW in 2007. In this year, the province produced a total amount of 17,638 GWh of electricity and consumed 16,410 GWh. The majority of power produced in the province was from thermal generating stations.

The NBSO's 10-Year Assessment[6] predicted that its grid net load demand would increase from 14,284 GWh in 2009/2010 to 15,096 GWh in 2018/2019, an average annual net energy growth rate of 0.6%. Its peak load was expected to increase by average rate of 0.6% per year over the same period, i.e. from 3,000 MW to 3,180 MW. The Assessment presented its development plans of generation and transmission to supply the forecast demands.

Based on the information presented in the NSBO's 10-Year Assessment, Figure 1-11 and Figure 1-12 display the generation resources for the province of New Brunswick.

1.8 QUEBEC

Hydro-Québec is the main power utility in Quebec and is owned by the provincial government. It has three divisions focusing on electricity generation (Hydro-Québec Production), transmission (Hydro-Québec TransÉnergie) and distribution (Hydro-Québec Distribution). It also has a division that acts as primary design-build contractor for generation and transmission projects (Hydro-Québec Équipement).

Hydro-Québec Production generates power for the Quebec market and sells its surpluses on wholesale markets outside Quebec. It has obligation to supply Quebec consumers 165 TWh per year as per the heritage pool contract. It is also active in arbitraging and purchase/resale transactions. Private utilities also supply power on the open market to HQD. Transmission and distribution is regulated on a cost basis. Hydro-Québec TransÉnergie has an Open Access Transmission Tariff (OATT) in place.

As of December 2007, the province had a total installed generating capacity of 41,018 MW, of which most was from water power. In 2007, the province produced a total amount of 191,962 GWh of electricity while its total consumption over the same period was 210,014 GWh. Most of the difference was supplied by the Churchill Falls generating station located in Labrador.

Hydro Quebec published its Strategic Plan 2006-2010 on September 15, 2006, which focused on three main priorities: energy efficiency, complementary development of hydro electricity and wind power (two major renewable resources in Quebec) and technological innovation[7]. The Plan

[6] 10-Year Assessment of the Adequacy of Generation and Transmission Facilities in New Brunswick 2009-2019, New Brunswick System Operator

[7] Strategic Plan 2006-2010, Hydro Quebec, September 15, 2006

indicated that electricity sales in Quebec would reach 182.4 TWh by 2014, an increase of 13.2 TWh over 2005. The annual growth rate would be 0.8% or 1.5 TWh. To provide Quebec with a secure supply of electricity, Hydro-Quebec Distribution produces an Electricity Supply Plan every three years, which represents its customers' forecast electricity needs and proposes means to meet the demand. This plan is reviewed and approved by the Régie de l'énergie and followed up annually.

The bar charts in Figure 1-13 and Figure 1-14 show the generating resources of Hydro-Quebec over 2012 and 2014, which are based on its Strategic Plan and Statistics Canada's Electric Power Generation, Transmission and Distribution – 2007.

1.9 ONTARIO

The Ontario electric system is owned and operated by a mix of provincially owned, municipally owned, investor owned and jointly owned companies. The main players on the Ontario electricity market include the Ontario Power Generation (OPG), Hydro One, Bruce Power, the Independent Electricity System Operator (IESO), the Ontario Power Authority (OPA), municipal distribution utilities, independent power producers, etc. The main functions of some of them are summarized as follows:

The OPG is a provincially-owned electricity generation company, of which hydroelectric, nuclear and fossil fuel stations generate approximately 70% of Ontario's electricity. The OPG has over 22,000 MW installed generation capacity.

Hydro One is a provincially-owned company that operates the majority of Ontario's transmission lines. Hydro One also serves as an electricity local distribution company in some areas of the province.

Bruce Power is Canada's first private nuclear generator, which has eight CANDU reactors in Bruce A and B generating stations with a total capacity of some 6,200 MW.

The IESO manages the reliability of Ontario's power system and forecasts the demand and supply of electricity over short-term. The IESO also operates the wholesale electricity market, while ensuring fair competition through market surveillance.

The OPA was established by the Electricity Restructuring Act, 2004 which sets out the following objectives for the organization[8]:

1. To forecast electricity demand and the adequacy and reliability of electricity resources for Ontario for the medium and long-term.
2. To conduct independent planning for electricity generation, demand management, conservation and transmission and develop integrated power system plans for Ontario.
3. To engage in activities in support of the goal of ensuring adequate, reliable and secure electricity supply and resources in Ontario.
4. To engage in activities to facilitate the diversification of sources of electricity supply by promoting the use of cleaner energy sources and technologies, including alternative energy sources and renewable energy sources.

[8] http://www.powerauthority.on.ca/Page.asp?PageID=122&ContentID=822&SiteNodeID=119&BL_ExpandID=

5. To establish system-wide goals for the amount of electricity to be produced from alternative energy sources and renewable energy sources.
6. To engage in activities that facilitate load management.
7. To engage in activities that promote electricity conservation and the efficient use of electricity.
8. To assist the Ontario Energy Board by facilitating stability in rates for certain types of customers.
9. To collect and provide to the public and the Ontario Energy Board information relating to medium and long term electricity needs of Ontario and the adequacy and reliability of the integrated power system to meet those needs.

As of December 2007, there was a total of 32,166 MW generation capacity installed in Ontario. In this year, the generation fleet produced a total of 158,234 GWh of electricity while the province electricity consumption amounted to 153,425 GWh.

On August 29, 2007, the OPA filed an application for approval of the Integrated Power System Plan (IPSP) with the Ontario Energy Board. The IPSP predicated that Ontario's annual peak demand would increase to 33,677 MW by 2027 from its 2005 level of 25,823 MW, an increase of more than 7,800 MW. The IPSP presented various plans to add more generation capacity and transmission lines to the system to meet the growing demand. It also addressed the issues related to phasing out coal fired generation, increase of renewable power generation, refurbishment/retirement of existing nuclear generating units and addition of new nuclear generating units.

The OPA IPSP described a couple of cases for meeting the growing load demands. Figure 1-15 and Figure 1-16 shows the development of effective generating capacity for 2015 and 2025. Since submission of the IPSP, the Government of Ontario had directed the OPA to revise the IPSP and increase renewable power generation in Ontario.

1.10 MANITOBA

The major utility in Manitoba is Manitoba Hydro, a crown corporation. Manitoba Hydro is a vertically integrated utility responsible for power generation, transmission and distribution in the province.

Despite its monopoly on transmission, Manitoba Hydro has an Open Access Transmission Tariff (OATT) in place that allows transmission customers non-discriminatory access to the system.

The vast majority of electricity in Manitoba is generated from 14 hydro stations, many of which are located in the northern part of the province. The Nelson River HDVC lines run between Lake Winnipegosis and Lake Winnipeg connect the northern stations to the southern load areas.

Power generation in Manitoba is almost entirely hydroelectric. Installed capacity in 2007 was 5,627 MW, of which 104 MW was from private wind power, 22 MW from self producers and the remainder from Manitoba Hydro (5029 MW hydro and the balance thermal). In 2007, the province produced a total of 34,403 GWh of electricity and consumed 22,235 GWh. Manitoba Hydro sells excess power through 12 tie lines to Saskatchewan, Ontario, North Dakota and Minnesota.

As per the 10-Year Development Plan – 2008 prepared by Manitoba Hydro[9], the Company forecasted that its electrical energy requirement would increase to 28,453 GWh in 2017/2018 from 23,596 GWh in 2007/2008, for an average annual growth rate of 1.9%. Its peak demand would increase from 4,225 MW in 2007/2008 to 5,029 MW in 2017/2018, for an average annual growth rate of 1.8%. The Plan proposed additions, enhancements, replacements, and repairs to ensure that the transmission system continues to meet Manitoba Hydro's mandate of serving the province with a reliable supply of electricity as well as meeting the performance requirements of Manitoba Hydro and its neighbouring utilities in Canada and the United States.

1.11 SASKATCHEWAN

SaskPower, a provincial Crown Corporation, is the main electricity supplier in Saskatchewan and is involved in power generation, transmission and distribution. It introduced an Open Access Transmission Tariff (OATT) in 2001.

As of December 2007, the province had a total installed generating capacity of 3,879 MW, of which 3,344 MW was owned and operated by SaskPower. Most generating capacity was from thermal technologies. In 2007, the province produced a total of 20,574 GWh of electricity and consumed 20,578 GWh over the same period.

As per the information presented on the SaskPower's website[10], SaskPower load is expected to grow by 34% over the next 10 years, i.e. between 2008 and 2018. Combined with the need to replace aging generation facilities, SaskPower would need a total of approximately 1,700 MW of new supply by 2020 and approximately 3,700 MW by 2030. On the website, SaskPower lists its short, medium and long term strategies to supply the growing demands.

1.12 ALBERTA

Alberta's electricity system is owned and operated by a mix of investor-owned and municipally owned companies, not by the Alberta government. To ensure Albertans of a long-term, reliable supply of competitively priced electricity, Alberta Energy, on behalf of the Government of Alberta develops, supports and monitors the framework for bringing new generation on-line, competitive electricity markets, and efficient delivery systems.

Alberta's retail electricity market gives consumers a choice of service providers. More than 20 companies are currently competing to sell power to the province's larger commercial and industrial users, who account for roughly two-thirds of all electricity usage in Alberta. With the continued development of the retail market more retail options will be available to smaller consumers such as residential, farm and small commercial customers.

In 2007, the Province of Alberta consumed a total of 68,073 GWh of electricity, with a total installed generating capacity of 11,851 MW and net generation of 67,432 GWh[1].

AESO is the Alberta electric system operator, who is responsible for the safe, reliable and economic planning and operation of the Alberta Interconnected Electric System (AIES).

[9] 10-Year Development Plan – 2008 for Manitoba Hydro's Electric Transmission System, Manitoba Hydro
[10] http://www.saskpower.com/poweringyourfuture/tomorrow/strategies.shtml

The AESO 10-Year Transmission System Plan[11] forecasted that the Alberta would have an annual peak demand of some 13,170 MW to 14,200 MW by 2016/17 depending on the growth of industrial load, comparing with the 2005/06 peak demand of 9,580 MW. The Alberta 10-Year Generation Outlook presented in the AESO 10-Year Plan provided the long-term conceptual outlook for generation development in Alberta. This outlook recognized that generation development is a non-regulated competitive business. It is thus, not possible to forecast the exact timing and location of generation development 10 years into the future. For this reason, the Alberta 10-Year Generation Outlook included scenarios of the types and locations of potential new generation. Figure 1-17 and Figure 1-18 present the expected effective generating capacity in Alberta for 2005, 2016 and 2024, which are based on the information in the AESO 10-Year Transmission System Plan and 20-Year Outlook Document[12].

Alberta Energy published its Provincial Energy Strategy in December 2008[13]. This strategy set future policy direction for clean energy production, wise energy use and sustained economic prosperity related to energy. The strategy contains policies and recommendations that will be implemented by the Department of Energy and other departments.

The Government will develop an implementation plan that will include a monitoring process to facilitate the assessment of the progress towards meeting the policy objectives of the strategy and allow the department to reassess its objectives and strategies on an ongoing basis as conditions evolve. Taking into account the need for departments to prepare, plan and execute their respective policy recommendations, the implementation plan will incorporate three horizons: short-term, medium-term and long-term. Benchmarks and outcomes will be identified over each horizon.

1.13 BRITISH COLUMBIA

The electricity consumption in the province of British Columbia is supplied by public utilities, private utilities, independent power producers (IPPs) and self-producers. Although the electricity market is presently not open for competition, the transmission function has been unbundled from the traditional integrated power utility. Each of the power utilities has its mandates and service area defined. The main players in the provincial electricity market include the British Columbia Hydro and Power Authority (BC Hydro), British Columbia Transmission Corporation (BCTC), Columbia Power Corporation (CPC) and FortisBC. IPPs sell their output to power utilities.

BC Hydro owning approximately 75% of the total installed capacity in the province is a provincial Crown corporation and its primary business activities are the generation and distribution of electricity to the most regions of the province. BCTC is also a provincial Crown corporation that plans, builds, operates and maintains the province's publicly-owned electrical transmission system. CPC, a provincial Crown corporation, owns and administers the hydroelectric power assets (some 330 MW generating capacity) purchased by the Province in the Columbia Basin. FortisBC with a total installed generating capacity some 220 MW is an investor-owned power utility generating and distributing electricity to homes and businesses in the southern interior of British Columbia.

In 2007, the total electricity consumption of the province amounted to some 74,665 GWh, with a total installed generating capacity of some 14,832 MW and net generation of 71,833 GWh[1].

[11] 10-Year Transmission System Plan 2007 – 2016, AESO, February 2007
[12] 20-Year Outlook Document 2005-2004, AESO, June 2005
[13] Launching Alberta's Energy Future, Provincial Energy Strategy

In its 2008 Long Term Acquisition Plan (LTAP) submitted to the British Columbia Utilities Commission (BCUC), BC Hydro forecasted that its energy demand in 2008 would be some 58,700 GWh and it would reach some 77,225 GWh (before implementation of demand side management programs) by 2027. The LTAP also presents its generation development plans to meet the load growth. Figure 1-19 and Figure 1-20 shows the dependable generating capacity of BC Hydro for 2009, 2018 and 2028, which are based on the information presented in the BC Hydro's 2008 LTAP. The generating capacity also includes those contributed by power purchase agreements signed with IPPs.

The Government of British Columbia published its Energy Plan in February 2007[14], which established the following main goals for the electricity sector:

1. Achieving self-sufficiency to meet electricity needs by 2016,
2. Establishing a standard offer program for clean electricity projects up to 10 MW,
3. The BCTC 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,
4. Ensuring adequate transmission capacity by developing and implementing a transmission congestion relief policy,
5. Ensuring the province remains consistent with North American transmission reliability standards,
6. Continuing public ownership of BC Hydro and its heritage assets, and the BCTC,
7. Establishing the existing heritage contract in perpetuity,
8. Investing 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,
9. All new electricity generation projects will have zero net greenhouse gas emissions,
10. Zero net greenhouse gas emissions from existing thermal generation power plants by 2016,
11. Requiring zero greenhouse gas emissions from any coal thermal electricity facilities,
12. Ensuring clean or renewable electricity generation continues to account for at least 90% of total generation
13. 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,
14. No nuclear power,
15. Reviewing BCUC's role in considering social and environmental costs and benefits,
16. Ensuring the procurement of electricity appropriately recognizes the value of aggregated intermittent resources,

[14] The BC Energy Plan, A Vision for Clean Energy Leadership

17. Working with BC Hydro and parties involved to continue to improve the procurement process for electricity, and
18. Pursuing the Government and BC Hydro's planned Remote Community Electrification program to expand or take over electricity service to remote community in British Columbia.

1.14 YUKON

The primary utility in the Yukon Territory is Yukon Energy, a government-owned entity. It is involved in generation, transmission and some distribution in the territory. Yukon Energy also sells power to Yukon Electric, which serves many retail electricity customers in the territory. Yukon's transmission grid consists of 138 kV, 66-69 kV and some lower voltage lines.

The territory had a total installed capacity of 111 MW in 2007. Over the same period, the territory produced and consumed an amount of 355 GWh of electricity.

Yukon is building a new 172 km 138 kV line from Carmacks to Stewart Crossing in the Central Yukon, with a spur line to a new mining facility.

1.15 NORTHWEST

Northwest Territories Power Corporation (NTPC), a Crown Corporation, is responsible for electricity generation and delivery in the Northwest Territories. The territories do not have an integrated electric system and have a total of 28 isolated electric systems. Sources of power generation include hydro, gas and diesel.

As of December 2007, the territories had a total installed generating capacity of 151 MW. The total electricity production and consumption was 686 GWh in 2007.

1.16 NUNAVUT

The Government of Nunavut owns Qulliq Energy Corporation (formerly Nunavut Power Corporation) which is responsible for generating and supplying electricity in the territory. It operates 27 stand alone diesel plants, which are the sole source of electricity in the region. Each community has independent generation and distribution.

In 2007, the territory had a total of 54 MW installed generating capacity. It produced and generated 149 GWh of electricity over the same time period.

Table 1-1: Electricity Generation (GWh) in Canada – 2007

Province	Low GHG Emitting				GHG Emitting				Total
	Hydro	Wind & Tidal	Nuclear	Subtotal	Steam	Internal Combustion	Combustion Turbine	Subtotal	
Newfoundland and Labrador	40,048			**40,048**	1,256	43	235	**1,534**	**41,582**
Prince Edward Island		40		**40**	5			**5**	**45**
Nova Scotia	925	177		**1,102**	11,219		254	**11,473**	**12,575**
New Brunswick	2,803		4,119	**6,922**	8,595	6	2,116	**10,717**	**17,639**
Quebec	181,100	617	4,322	**186,039**	2,562	272	3,089	**5,923**	**191,962**
Ontario	34,336	493	79,750	**114,579**	34,343	2,879	6,433	**43,655**	**158,234**
Manitoba	33,513	325		**33,838**	512	13	40	**565**	**34,403**
Saskatchewan	4,393	579		**4,972**	14,272	1	1,329	**15,602**	**20,574**
Alberta	2,141	716		**2,857**	50,180	492	13,903	**64,575**	**67,432**
British Columbia	64,288			**64,288**	5,009	83	2,454	**7,546**	**71,834**
Yukon	331			**331**		24		**24**	**355**
Northwest Territories	250			**250**		298	138	**436**	**686**
Nunavut				**-**		149		**149**	**149**
Total	**364,128**	**2,947**	**88,191**	**455,266**	**127,953**	**4,260**	**29,991**	**162,204**	**617,470**

Source: Electric Power Generation, Transmission and Distribution – 2007, Statistics Canada

Table 1-2: Installed Generating Capacity (MW) in Canada -- 2007

Province	Low GHG Emitting				GHG Emitting				Total
	Hydro	Wind & Tidal	Nuclear	Subtotal	Steam	Internal Combustion	Combustion Turbine	Subtotal	
Newfoundland and Labrador	6,796			**6,796**	490	24	43	**557**	**7,353**
Prince Edward Island		44		**44**	67		90	**157**	**201**
Nova Scotia	404	53		**457**	1,686		320	**2,006**	**2,463**
New Brunswick	923		680	**1,603**	2,149	14	769	**2,932**	**4,535**
Quebec	37,459	376	675	**38,510**	1,126	129	1,252	**2,507**	**41,017**
Ontario	8,350	414	11,990	**20,754**	9,748	66	1,599	**11,413**	**32,167**
Manitoba	5,029	104		**5,133**	119	10	365	**494**	**5,627**
Saskatchewan	855	171		**1,026**	2,213		640	**2,853**	**3,879**
Alberta	909	439		**1,348**	7,845	104	2,554	**10,503**	**11,851**
British Columbia	12,609			**12,609**	1,769	61	393	**2,223**	**14,832**
Yukon	78	1		**79**		32		**32**	**111**
Northwest Territories	25			**25**		99	27	**126**	**151**
Nunavut				**-**		54		**54**	**54**
Total	**73,437**	**1,602**	**13,345**	**88,384**	**27,212**	**593**	**8,052**	**35,857**	**124,241**

Source: Electric Power Generation, Transmission and Distribution – 2007, Statistics Canada

Figure 1-1: Electricity Generation and Consumption in Canada – 2007

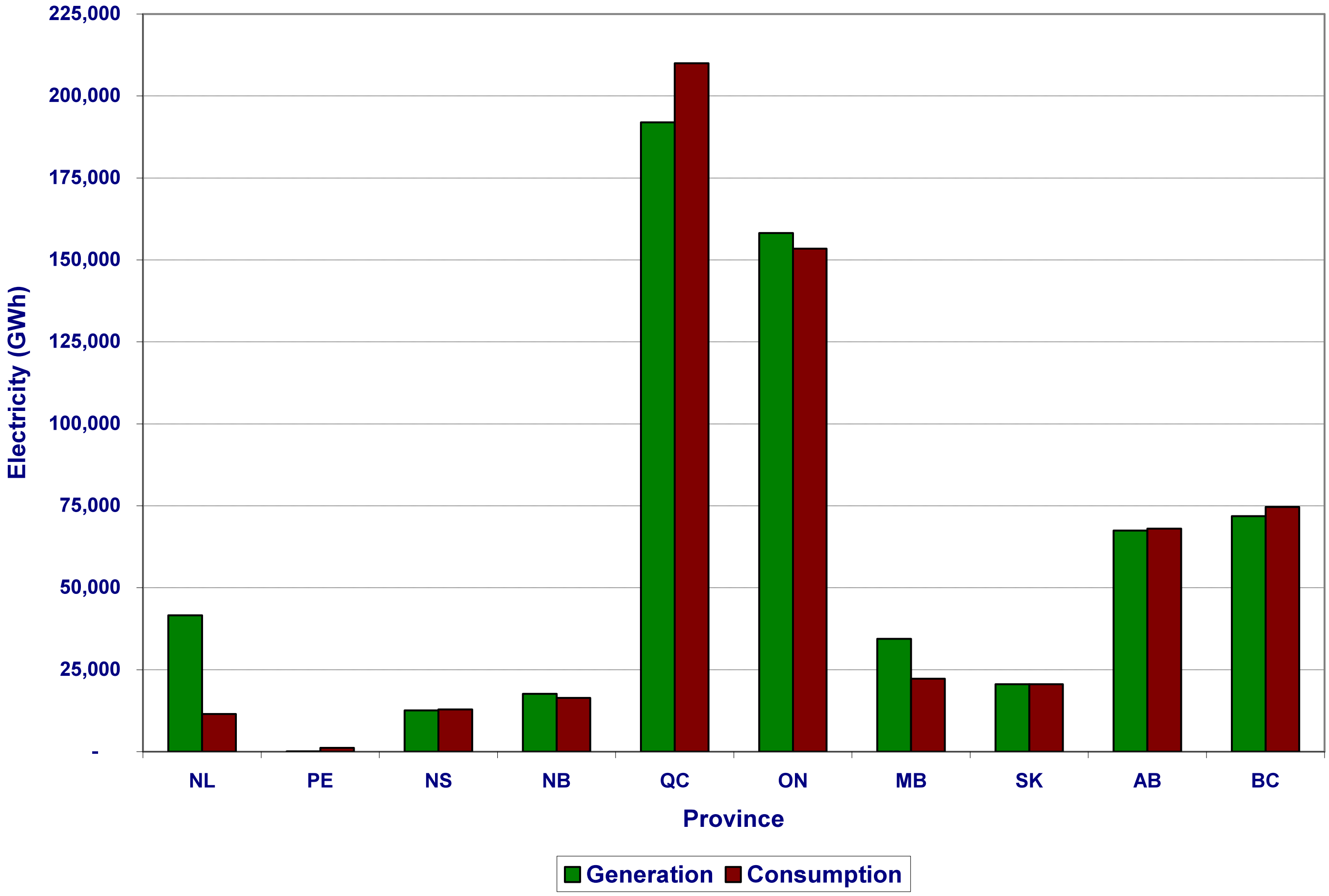


Figure 1-2: Electricity Generation (GWh) in Canada – 2007

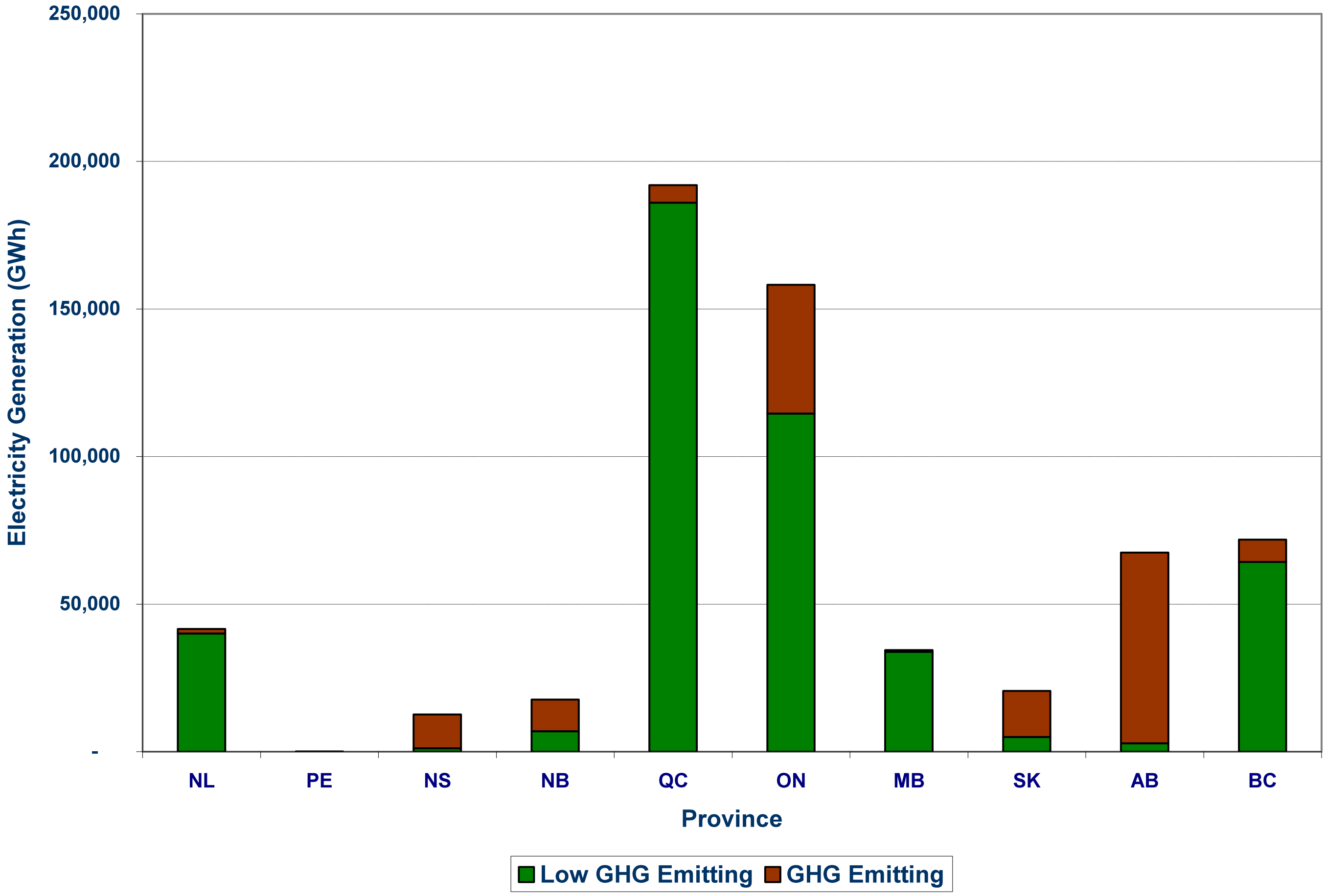


Figure 1-3: Electricity Generation (%) in Canada -- 2007

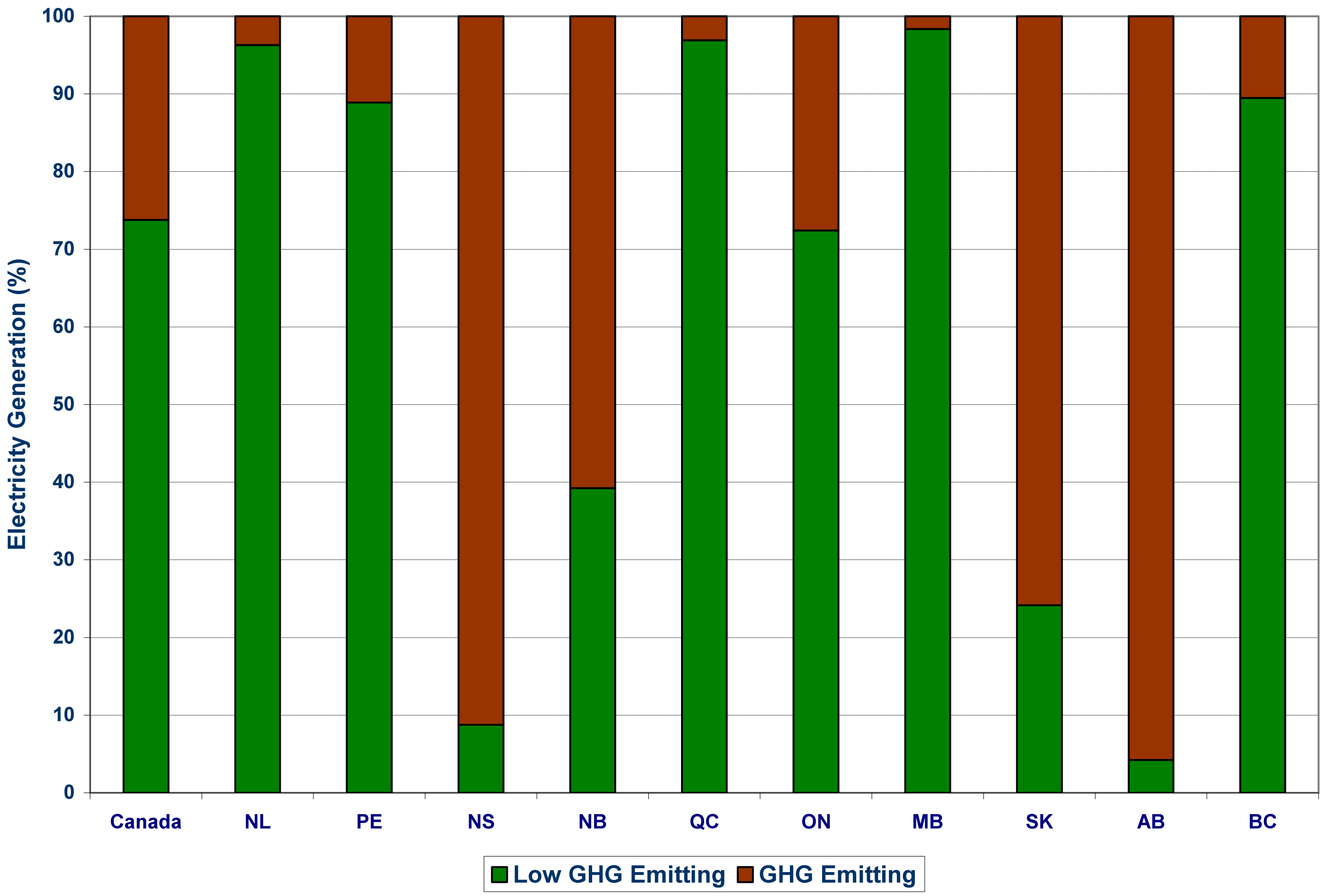


Figure 1-4: Installed Generating Capacity (MW) in Canada -- 2007

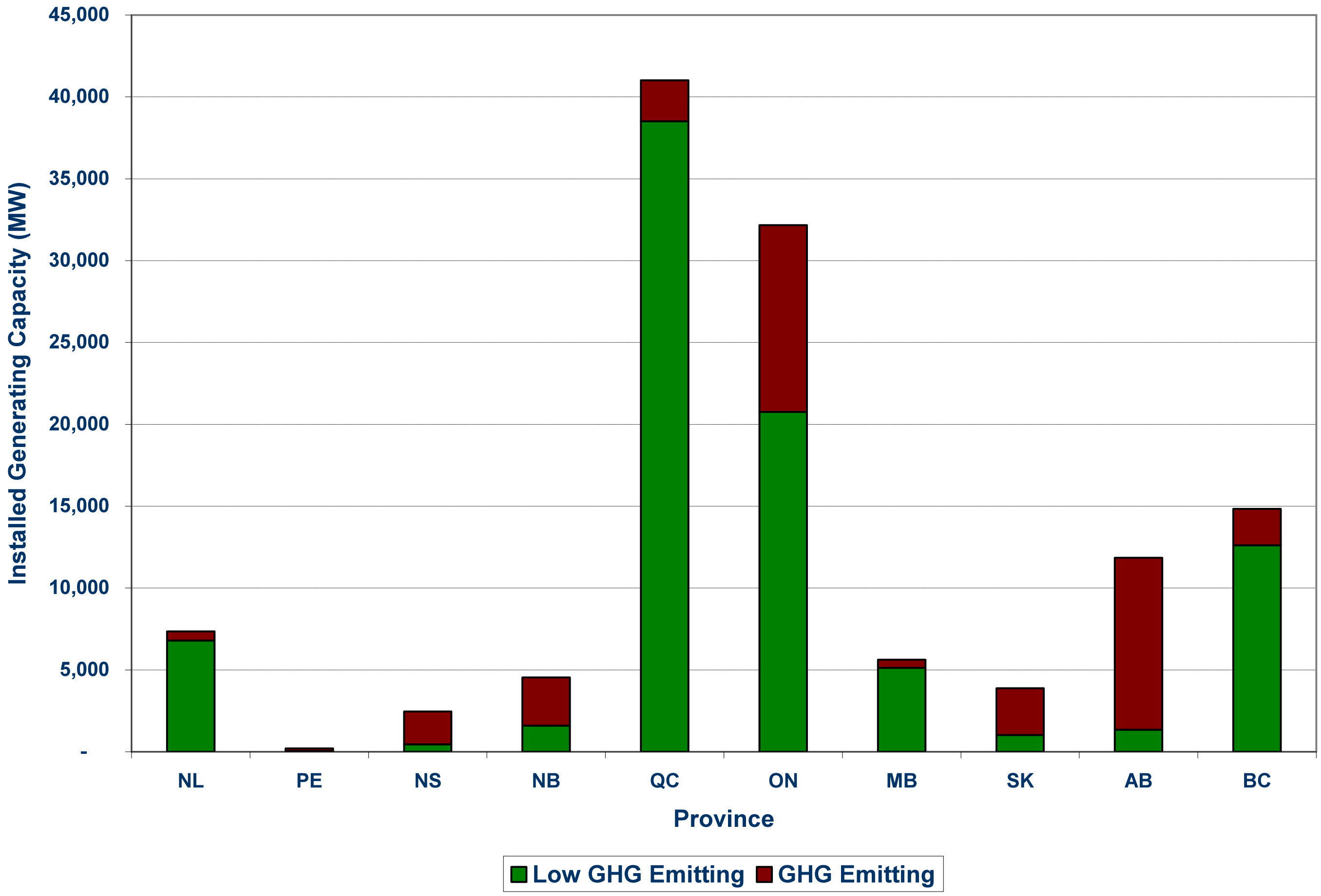


Figure 1-5: Hourly Load Variation (MW) Over 24 Hours

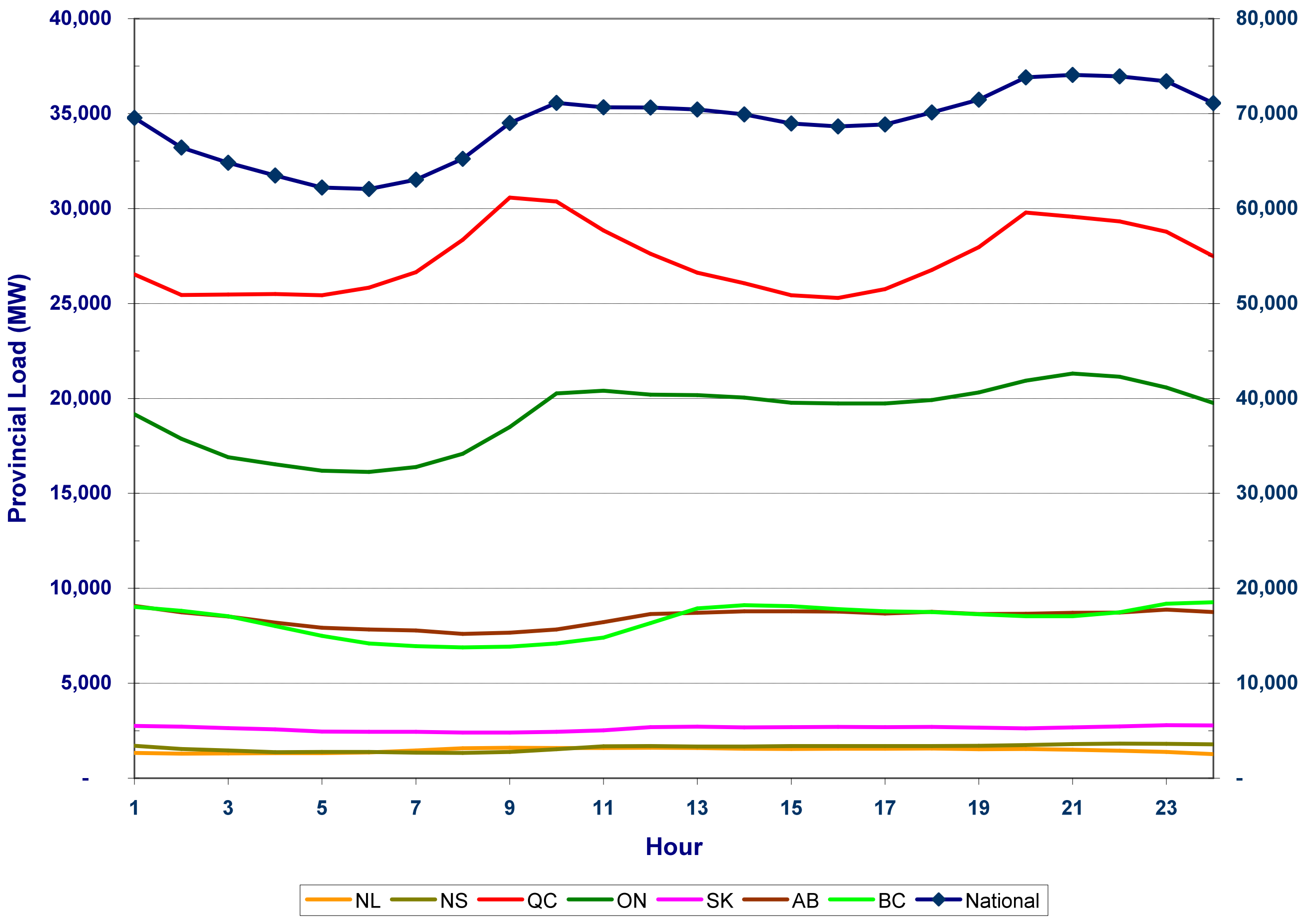


Figure 1-6: Hourly Load Variation (%) Over 24 Hour

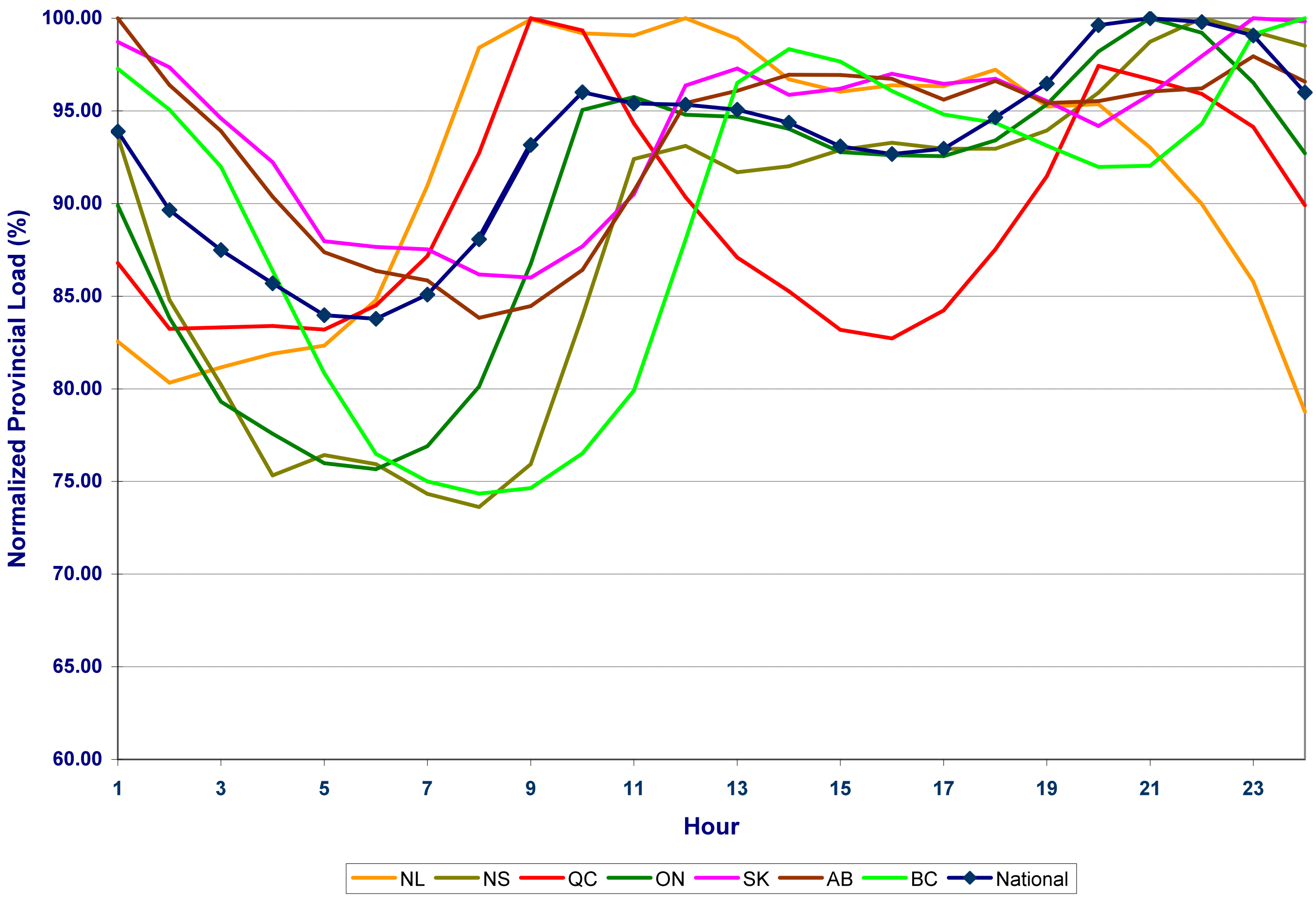


Figure 1-7: Net Generating Capacity (MW) of Newfoundland & Labrador

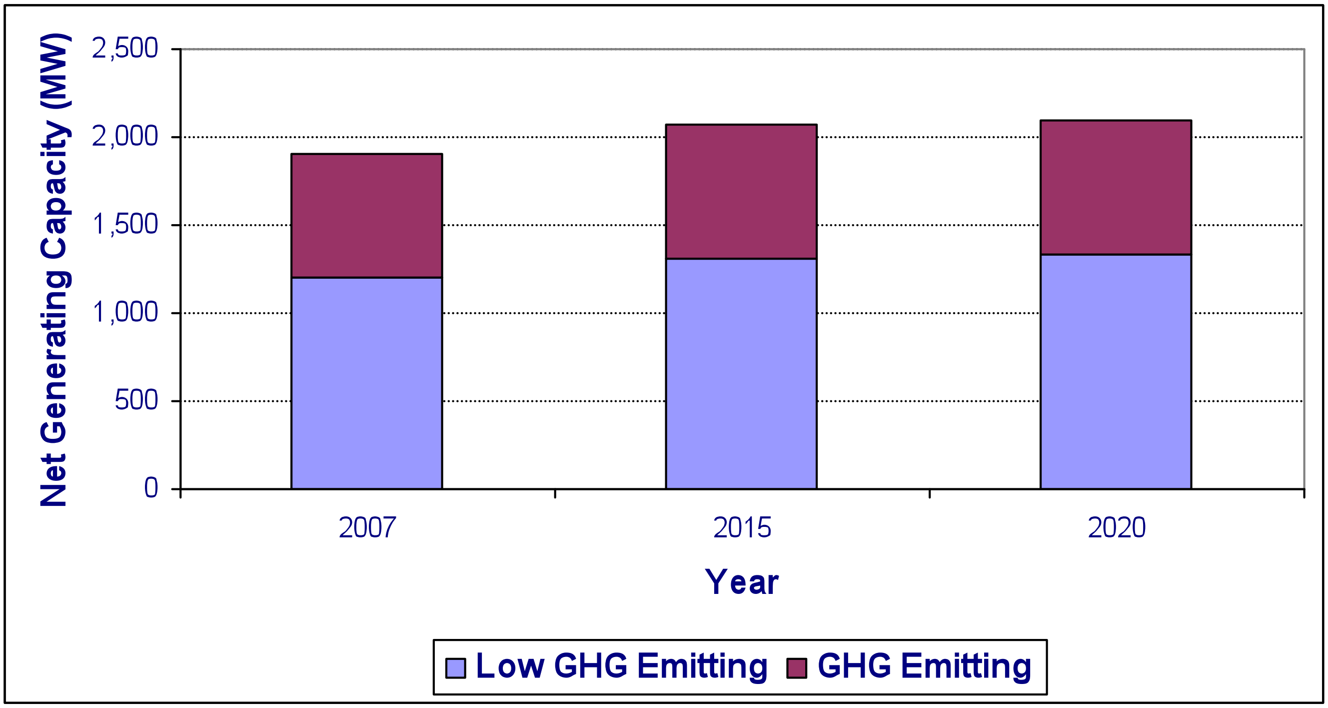


Figure 1-8: Net Generating Capacity (%) of Newfoundland & Labrador

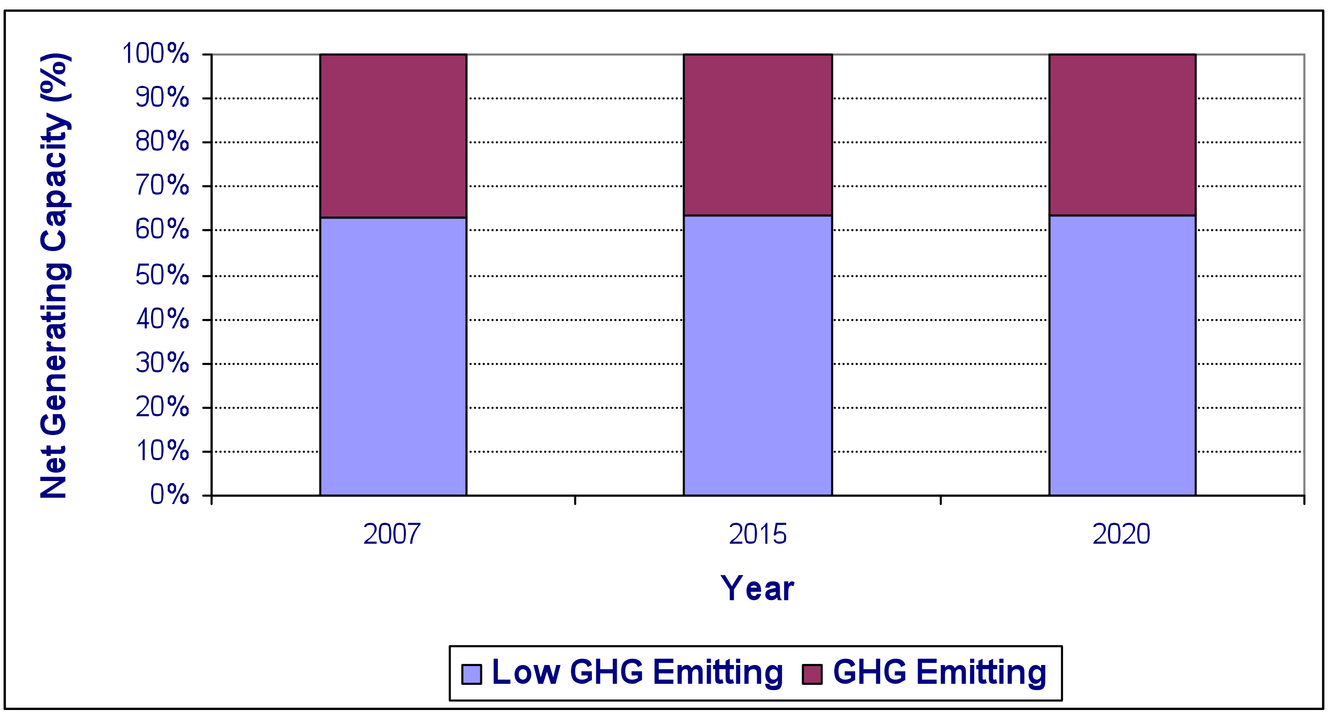


Figure 1-9: Firm Generating Capacity (MW) of NSPI

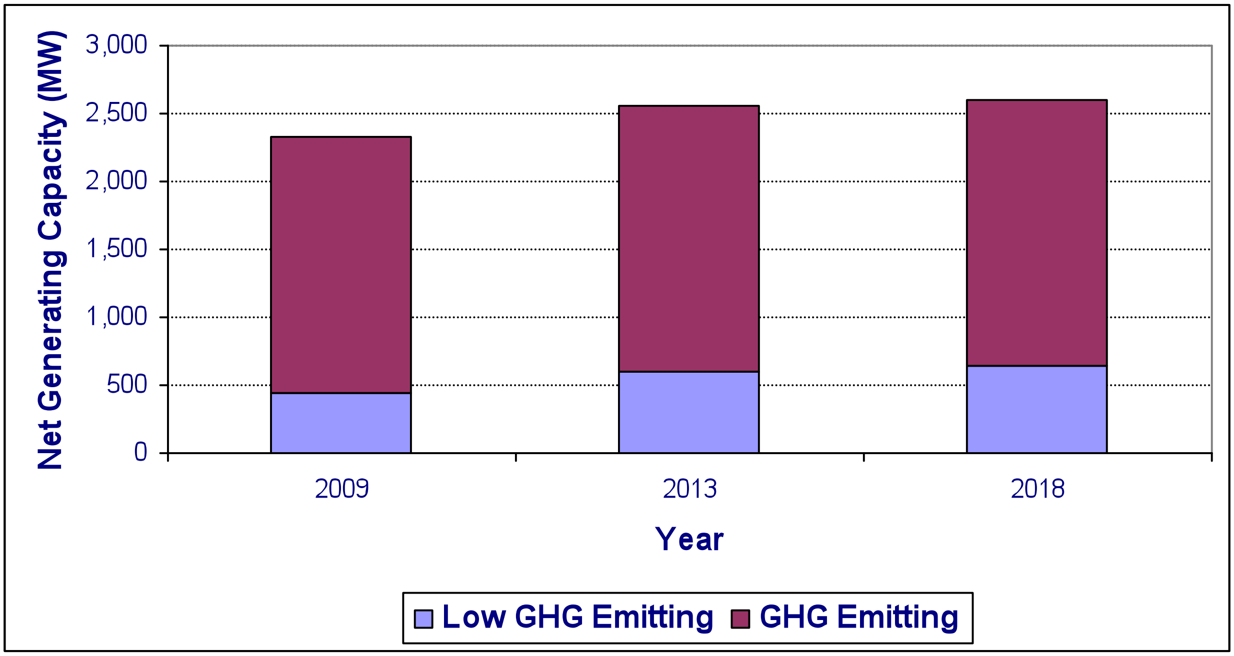


Figure 1-10: Firm Generating Capacity (%) of NSPI

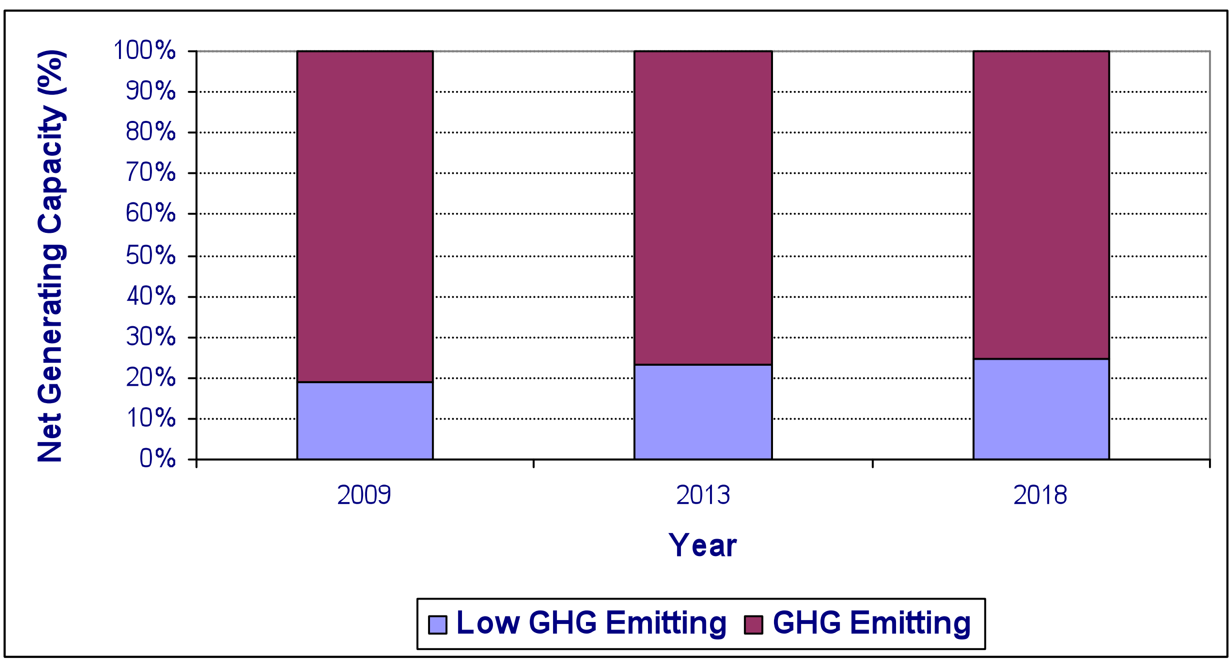


Figure 1-11: Generation Resources (MW) in New Brunswick

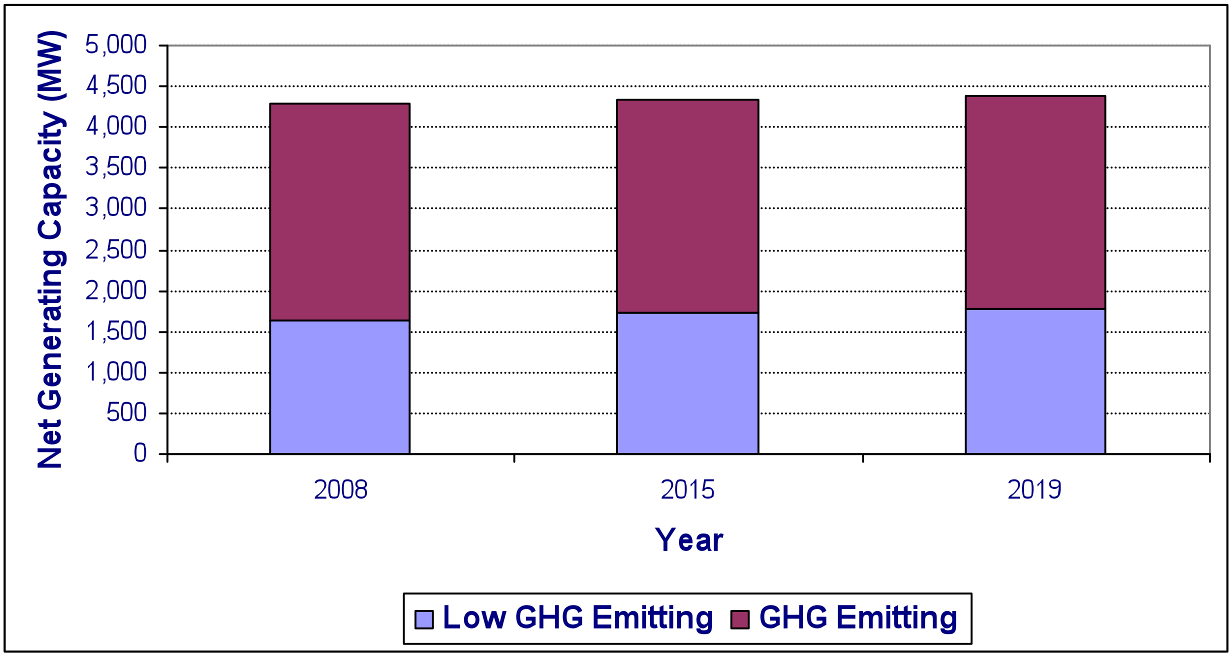


Figure 1-12: Generation Resources (%) in New Brunswick

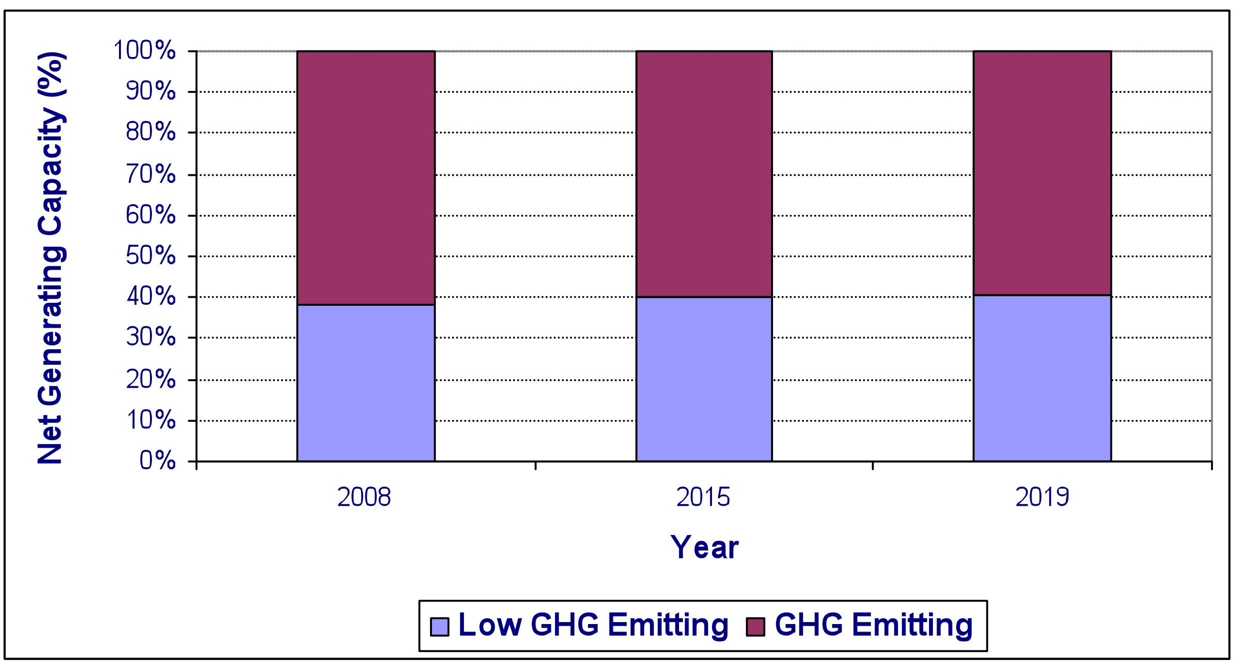


Figure 1-13: Generating Resources (MW) of Hydro-Quebec

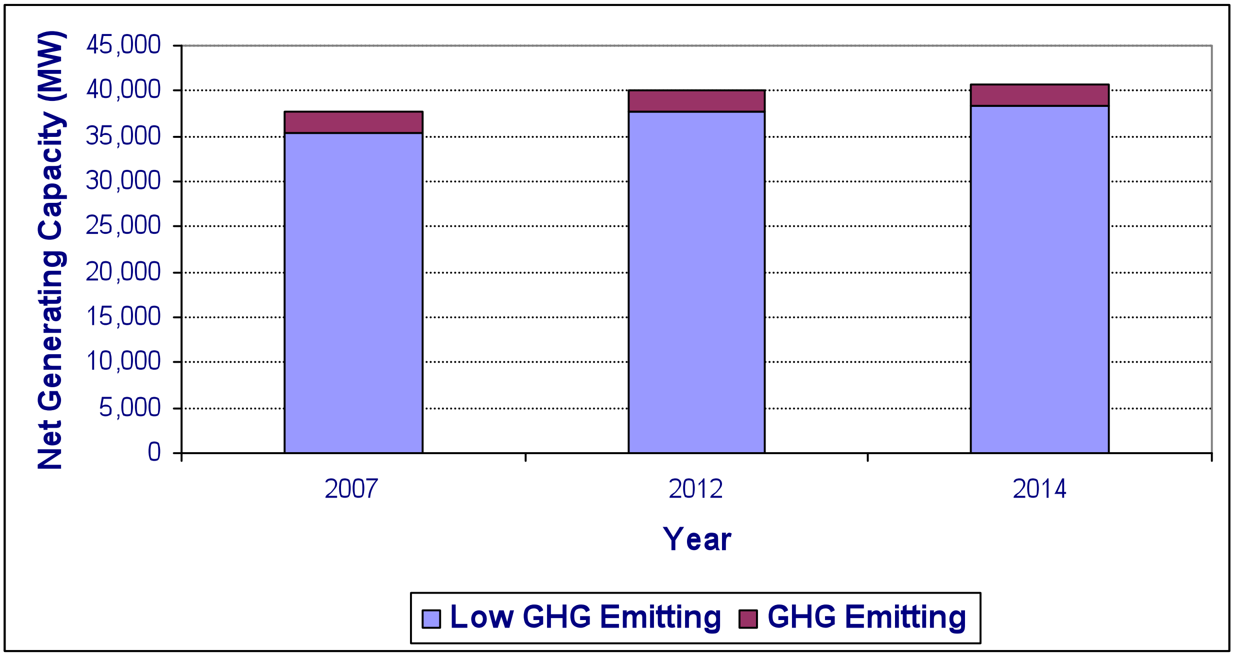


Figure 1-14: Generating Resources (%) of Hydro Quebec

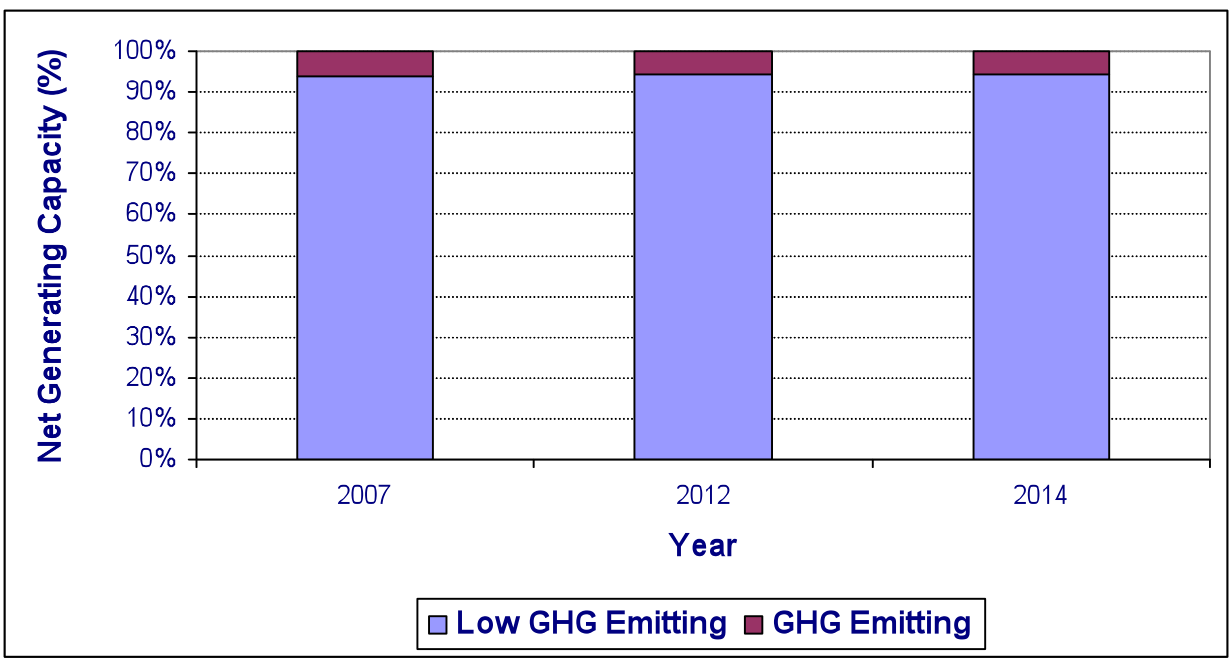


Figure 1-15: Effective Generating Capacity (MW) of Ontario

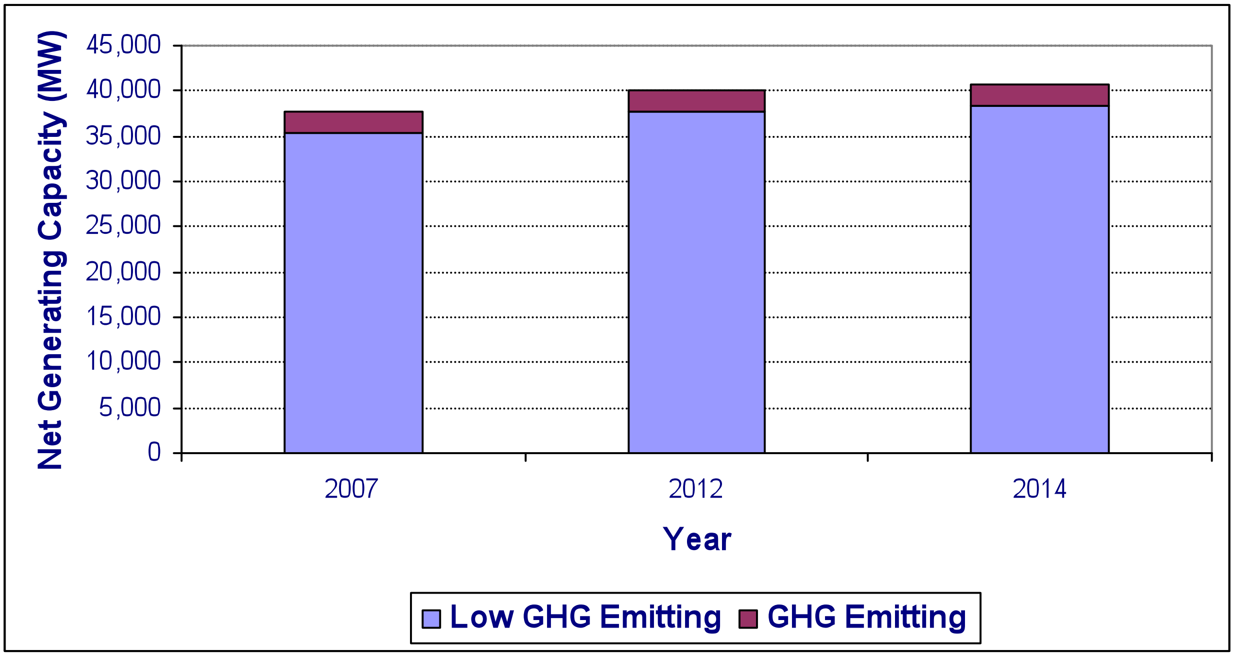


Figure 1-16: Effective Generating Capacity (%) of Ontario

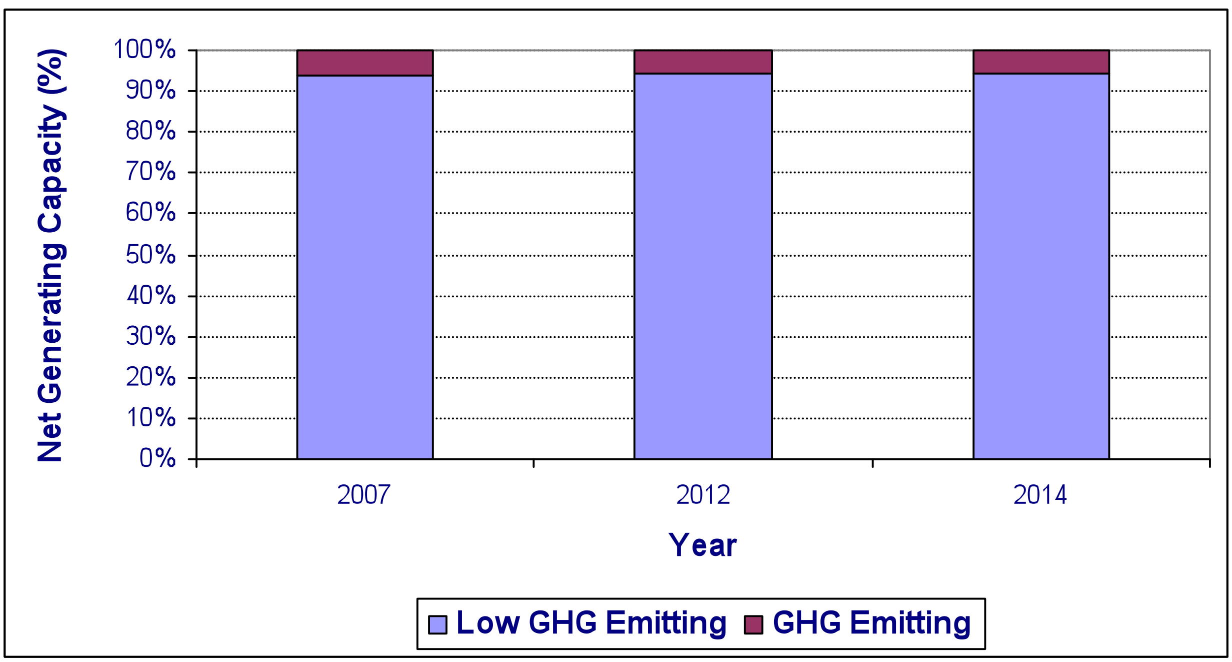


Figure 1-17: Effective Generating Capacity (MW) of Alberta

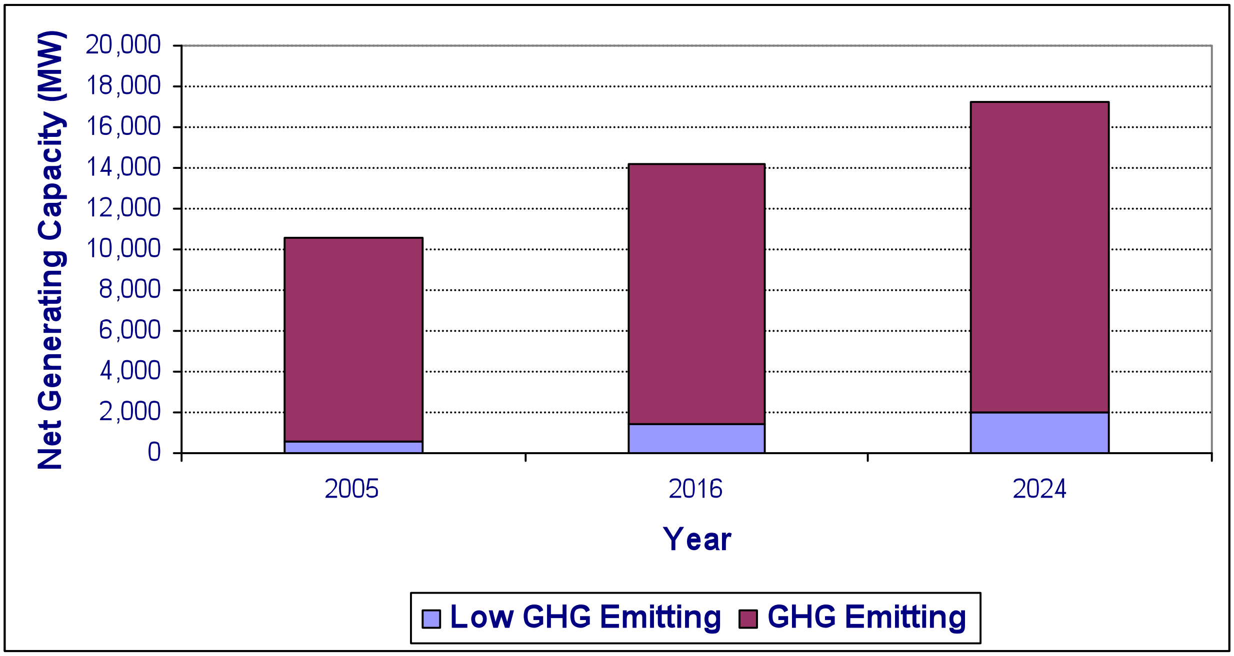


Figure 1-18: Effective Generating Capacity (%) of Alberta

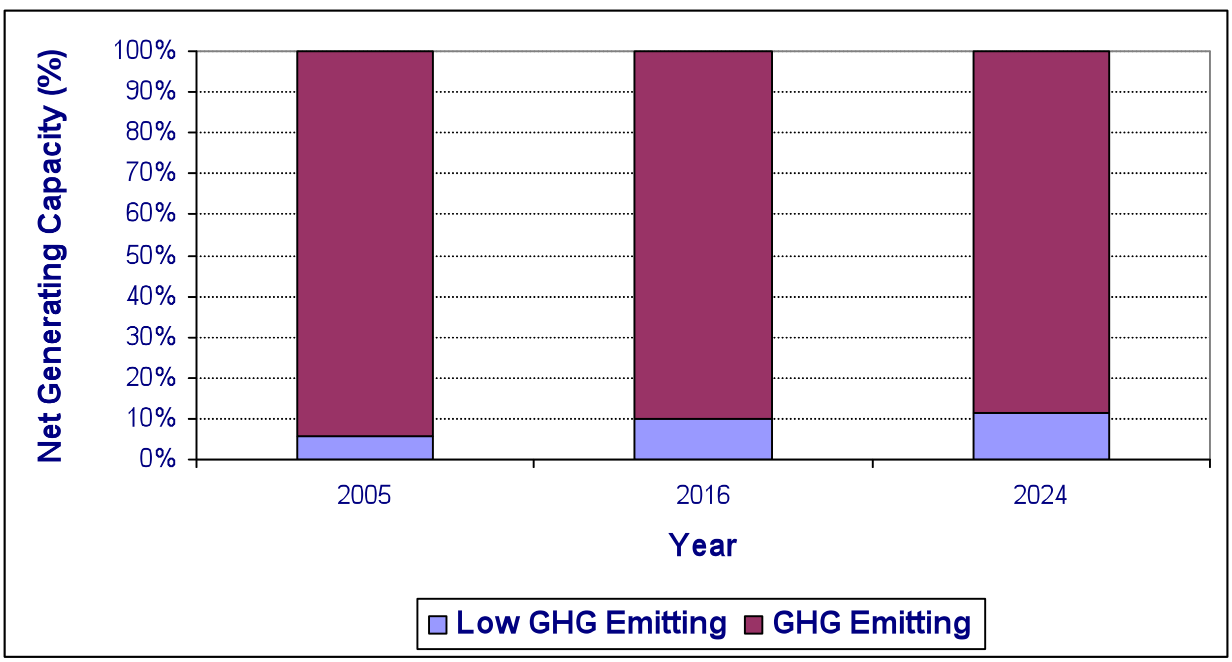


Figure 1-19: Dependable Generating Capacity (MW) of BC Hydro

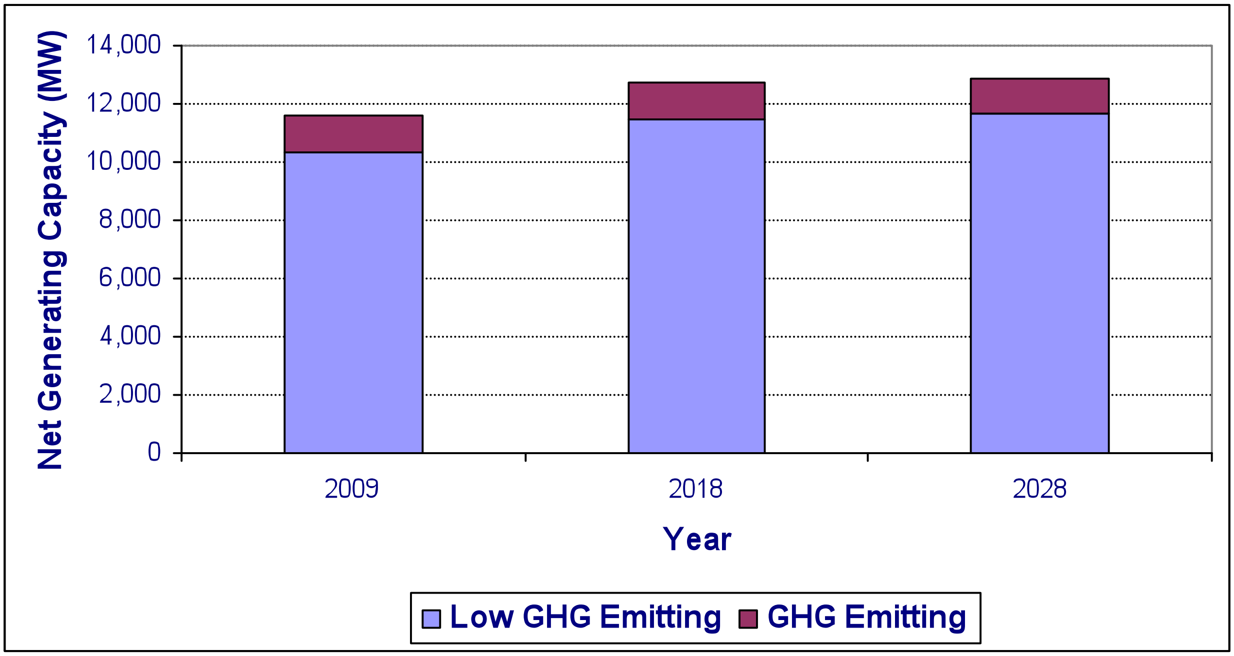
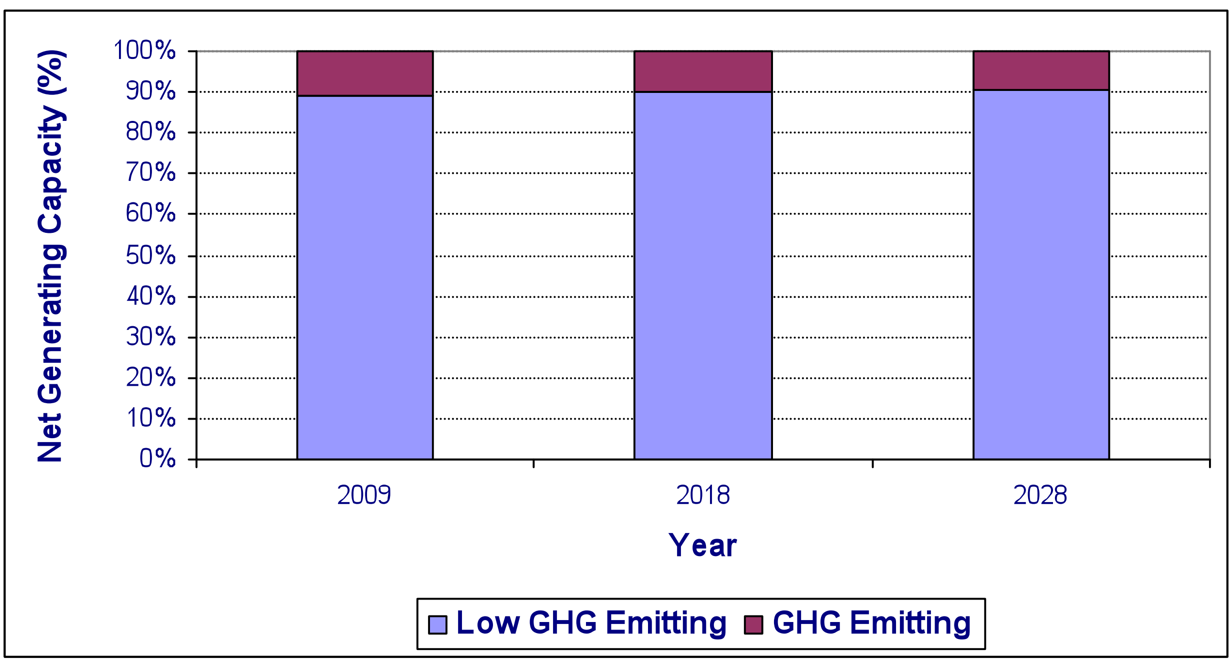


Figure 1-20: Dependable Generating Capacity (%) of BC Hydro



2. EXISTING AND PLANNED INTERCONNECTION PROJECTS

2.1 OVERVIEW

Figure 2-1 shows the existing interconnection transmission lines between two provinces and between a province and a state. It could be seen from this figure that many provinces currently have stronger interconnections in a north-south direction in order to allow for lucrative electricity trade with the United States, rather than in an east-westerly direction that would allow for a pan-Canadian electricity market to emerge. As interconnections between provincial grids often have small transfer capabilities, they do not allow for enough electricity to be sent across provincial borders to make up for large deficits in neighbouring provinces. For example, the interconnection between Ontario and Manitoba only has a transmission capacity of some 250 MW – equivalent to a small power plant. However, Manitoba's interconnection to the United States has an export capacity of some 2,150 MW – equivalent to a very large hydro generation station. Ontario can export up to some 4,000 MW to the United States and can import up to 3,300 MW from the United States.

2.2 NEWFOUNDLAND

Currently, Labrador is interconnected with Quebec, which allows it to sell power from the Churchill Falls generating station while the Newfoundland's Interconnected Island System is isolated from any other power grids.

NALCOR ENERGY has carried out a few studies on the development of Lower Churchill hydro project, which could have an installed capacity of approximately 3,000 MW. NLH has also conducted studies to interconnect the Island of Newfoundland with Labrador using HVDC to send power to the island from Labrador.

Figure 2-2 shows the existing and committed interconnection lines between various jurisdictions and Figure 2-3 shows the existing, committed and potential interconnection lines between various jurisdictions.

2.3 PRINCE EDWARD ISLAND

PEI currently has two 138 kV submarine connections to New Brunswick (100 MW each), which are owned by the Province and managed by Maritime Electric.

PEI intends to develop its wind power for export, which could require an additional interconnection circuit to New Brunswick. The current submarine cables do not have enough capacity for large scale of wind power export. The growth of domestic load demand could also trigger the requirement of additional interconnection circuit. However, one overhead line could run along utility corridors with the Confederation Bridge to New Brunswick, rather than development of more submarine cable.

2.4 NOVA SCOTIA

Nova Scotia is connected to New Brunswick through one 345 kV circuit and two 138 kV circuits that allow 350 MW of export capability and 300 MW of import capability. Any power transferred to or from other jurisdictions (e.g. Quebec, New England) must go through New Brunswick. Currently, transfer capability is constrained by Nova Scotia's system, not New Brunswick's.

A Maritimes Area Technical Planning Committee was established in 2008 to consider regional transmission plans and potential new interconnection lines or expansion of the existing interconnection. The committee has representatives from NSPI, NBSO, NB Power Transmission, Maritime Electric Co. and Northern Maine Independent System Administrator.

2.5 NEW BRUNSWICK

New Brunswick is interconnected to neighbouring power systems in Quebec, Nova Scotia, Prince Edward Island, New England, Northern Maine, and Eastern Maine. In 2007/2008 a second 345 kV interconnection circuit was added between New Brunswick and New England. The two interconnection circuits with Quebec are through High Voltage Direct Current (HVDC) stations and there is ability at each to radially connect a portion of the New Brunswick load directly to the Quebec system.

The table below shows the maximum transfer capability between New Brunswick and its neighbouring systems:

System	Import Capability (MW)	Export Capability (MW)
Quebec	1,000	720
New England	550	1,000
Nova Scotia	350	300
PEI	124	222
Maine	105	115

Although there are no interconnection circuits committed/planned to the New Brunswick system, NBSO has coordinated and participated in the studies for the following interconnection lines:

1. A second 345 kV circuit to Nova Scotia
2. An addition circuit to PEI
3. Increase of transfer capability to Maine
4. Increase of transfer capability to New England
5. Routing through New Brunswick of 740 MW of hydro power from the lower Churchill project in Newfoundland and Labrador

2.6 QUEBEC

As of December 31, 2006, Quebec has a total of 18 interconnection circuits to Ontario, Newfoundland and Labrador, New Brunswick, New York and New England. These circuits could provide a total export capacity of more than 7,100 MW and import capacity of more than 9,575 MW as listed in the table below:

System	Import Capability	Export Capability
Labrador	5,200 MW	0 MW
New Brunswick	785 MW	1,200 MW
Ontario	720 MW	1,295 MW
New England	1,870 MW	2,305 MW
New York	1,000 MW	2,125 MW

For future power transfer, an additional 1250 MW interconnection circuit to Ontario is currently under construction.

Although Hydro Quebec does not have any other committed/planned interconnection projects, the Company has assessed the capacity of its interconnections with neighbouring systems and examined ways to increase it.

2.7 ONTARIO

Ontario is part of a bigger North American electricity market and is interconnected with Manitoba, Quebec, New York, Minnesota and Michigan, through which, it is connected to other provinces and states. Among all of its interconnections, Ontario has the ability to import and export between 4,000 MW and 5,000 MW[15]. The following provides a summary on these existing interconnections[16]:

The Ontario-Manitoba interconnection consists of two 230 kV circuits and one 115 kV circuit. Ontario and Manitoba are synchronously connected on the two 230 kV circuits but are not on the 115 kV interconnection. The transfer-in and transfer-out capabilities of the interconnection are up to 343 MW and 275 MW respectively.

The Ontario-Minnesota interconnection has only one 115 kV circuit, which is synchronously connected to the two system. Through this circuit, Ontario could import up to 90 MW or export up to 140 MW.

The Ontario-Michigan interconnection includes two 230/345 kV circuits, one 230/115 kV circuit and one 230 kV circuit. At the present time, there is one phase angle regulator in service at Keith transmission station and two others, located at Lambton are by-passed. Ontario could import up to 1,750 MW from Michigan or export up to 2,200 MW to the state.

[15] The Ontario Reliability Outlook, Volume 2 Issue 1, March 2007, IESO
[16] Ontario Transmission System, June 23, 2006, IESO

The Ontario-New York Niagara interconnection consists of 60 Hz and 25 Hz at various voltage levels. For the 60 Hz interconnection, there are two 230/345 kV circuits, two 230 kV circuits and one 115 kV circuit. For the 25 Hz interconnection, there are one 115/69 kV circuit and one 69 kV circuit. Ontario through these circuits could purchase up to 1,650 MW from New York or sell up to 1,950 MW to the state.

The Ontario-New York St. Lawrence Interconnection includes two 230 kV circuits, which are synchronously connected to the two systems. The two interconnection circuits allow Ontario to exchange up to 400 MW with New York.

The Ontario-Quebec North interconnection consists two 115 kV circuits, which are non-synchronously connected to the two systems. Through the two circuits, Ontario could purchase up to 84 MW from Quebec or sell up to 110 MW to Quebec.

The Ontario-Quebec South interconnection includes one 230/345 kV circuit, four 230 kV circuits and two 115 kV circuit, which are non-synchronously connected to the two systems. Through these circuits, Ontario could purchase up to 1,548 MW from Quebec or sell up to 637 MW to the province.

Hydro One (Ontario Provincial Crown Transmission Company) and TransEnergie (Transmission Business Unit of Hydro Quebec) are currently building a 1,250 MW interconnection between Hawthorne transmission station in Ontario and Outouais station in Quebec consisting of a 230 kV line and back-to-back HVDC converters[15]. Work to accommodate the tie, scheduled to be in service in 2009, will also include improvements to the supply to stations in the Ottawa area.

In addition to the existing interconnections and the Ontario – Quebec back-to-back HVDC interconnection circuit under construction, Ontario does not have any other interconnection projects committed or planned. However, there were discussions on power purchases from Manitoba, Quebec and Newfoundland & Labrador. The following is excerpted from the OPA IPSP regarding the potential power purchases.

“The OPA is not recommending transmission reinforcement to enable a purchase of power from Manitoba. At this stage, the feasibility and economics of a potential purchase remain too uncertain. The OPA recommends that this option be further explored, and if the feasibility and economics become more definitive, then transmission development work may need to be undertaken.” Three transmission alternatives had been considered for transferring a large amount of power (1,500 MW or higher) to Ontario from Manitoba, which are (1) an HVDC system connecting northwestern Ontario to northeastern Ontario and then to southern Ontario, (2) an HVDC line that directly connects the Manitoba system at the border to a major network station near the greater Toronto area (GTA), and (3) a combination of HVDC and HVAC systems.

“The OPA is not recommending transmission reinforcement to enable a purchase of power from Labrador or Quebec. At this stage, the feasibility and economics of a potential purchase remain too uncertain. The OPA recommends that these options be further explored, and if the feasibility and economics become more definitive, then transmission development work may need to be undertaken.” The power produced in Newfoundland & Labrador would likely be transferred through the Hydro Quebec system as this is the direct path. However, there is also the possibility that the power could be transferred via an alternative path. The Ontario – Quebec interconnection circuit under construction was justified based on interchange opportunities between Ontario and Quebec. As there is no specific power purchase agreement between Ontario and Quebec related to this new circuit, there is a possibility that this new circuit could provide the path for a purchase from Labrador up to 1,250 MW, the maximum level of the new circuit.

2.8 MANITOBA

The electric system in Manitoba is interconnected to the transmission systems in Saskatchewan, Ontario, North Dakota and Minnesota by 12 interconnection circuits, which are listed as follows:

One 500 kV and three 230 kV transmission lines to the United States, with export capability up to 2,175 MW and import capability up to 700 MW

- One 500 kV and one 230 kV transmission lines to Minnesota
- Two of the 230 kV transmission lines to North Dakota

Three 230 kV and two 115 kV transmission lines to Saskatchewan, with a maximum transfer capability of 500 MW

Two phase-shifted 230 kV transmission lines and one non-synchronous 115 kV transmission line Ontario, with a transfer out capability of up to 275 MW and transfer in capability of up to 200 MW

Manitoba Hydro has been exploring the feasibility of developing new northern hydroelectric generation sites and new interconnection circuits. One on-going interconnection opportunity being explored is a high-capacity interconnection circuit from Manitoba to eastern Ontario, a distance in the order of 1,500 km. In addition, studies will be done to determine if the tie line capacity to the U.S. or Saskatchewan can be increased.

2.9 SASKATCHEWAN

Saskatchewan is interconnected with Manitoba, Alberta and North Dakota via three interconnections which are listed follows:

Three 230 kV and two 138 kV transmission lines to Manitoba

One 230 kV back-to-back HVDC transmission line to Alberta

One phase shifted 230 kV transmission line North Dakota

There were discussions to build a 138 kV merchant interconnection between Saskatchewan and Alberta in the Lloydminster area. However the status of this proposed project is unknown.

2.10 ALBERTA

Alberta has at present transmission interconnections with two other provinces. The interconnection to British Columbia, part of the Western Electricity Coordinating Council (WECC) consists of 500 kV and 138 kV circuits[17]. The export capability of the interconnection to B.C. has been significantly impacted by the heavily loaded intra-provincial transmission lines. Recent planning activities have

[17] 10-Year Transmission System Plan, 2007 – 2016, February 2007, Alberta Electric System Operator

restored some of this capability, especially by reducing the number of hours when exports were eliminated. Even so, the export capability remains significantly lower than it originally was.

A Working Group was formed by the Electricity and Alternative Energy Division of B.C. Energy, Mines and Resources and the Electricity Division of Alberta Energy to address the intertie capability between Alberta and B.C. In mid 2006 the Work Group formed the Alberta-

British Columbia Electricity Transmission Sub-committee with representatives from the BCTC and AESO.

The interconnection to Saskatchewan, part of the Midwest Reliability Organization (MRO) is a back-to-back HVDC terminal. The export capability to Saskatchewan has been reduced to 60 MW from 150 MW due to heavily loaded intra-provincial transmission lines.

The AESO has continued to work on several different initiatives with various parties related to interconnection capacity with neighbouring jurisdictions. These initiatives involve efforts to increase the capability of the existing interconnection as well as looking at future requirements that are either of a regulated or merchant nature or a combination of both.

The existing interconnections to B.C. and Saskatchewan are considered as “regulated” facilities. In addition to the two interconnections, proponents are progressing with two “merchant” interconnection projects. The AESO’s mandate is to facilitate such interconnections while ensuring that the Alberta interconnected electric system can be operated in a safe and reliable manner.

Montana Alberta Tie Ltd. (MATL) is progressing with its project to build a 300 MW, 240/230 kV interconnection between Lethbridge, Alberta and Great Falls, Montana. Its original in-service date of 2007 has been delayed.

The other merchant interconnection line currently proposed is the NorthernLights project being developed by TransCanada Energy Ltd. A Preliminary Assessment Application has been made to the AESO for a ±500 kV HVDC line from the Fort McMurray area to the Celilo area east of Portland, Oregon. The project is proposed to have an approximate rating of 3,000 MW and an anticipated in-service date in mid 2015.

The AESO participated in a study titled “Canada-Northwest-California Transmission Options Study” and carried out under the auspices of the Northwest Transmission Assessment Committee (NTAC) of the Northwest Power Pool (NWPP). The objective of this study was to provide high-level information on the feasibility of potential transmission projects to transfer a variety of new resources out of Canada into the Northwest and California.

2.11 BRITISH COLUMBIA

BCTC submitted its Transmission System Capital Plan F2010 and F2011 to BCUC in November 2008. The information presented in this subsection is excerpted from the BCTC Capital Plan.

The BCTC-operated transmission system is part of the Western Interconnection, which extends from BC and Alberta in the north, to northern Mexico in the south, and includes most systems in the western US. Interties to neighbouring systems provide opportunities for electricity trade, improve the overall reliability of the system, make backup energy resources available in emergencies, and improve control of frequency and power fluctuations. BCTC is a member of the Western Electricity Coordinating Council (WECC).

The BCTC transmission system is interconnected with Alberta by one 500 kV line from Cranbrook to Langdon Substation in Alberta and by two 138 kV lines from Natal Substation near Sparwood to the AltaLink network in Alberta. The current total transfer capability of the three interconnection lines is some 850 MW less transmission reliability margin. A system impact study recently completed by BCTC identified that the firm total transfer capability of the BC to Alberta Path could be increased to 1200 MW with some network upgrades.

The interconnection between the BC system and BPA's system in Washington State includes two interties: the 500 kV Westside Intertie and the 230 kV Eastside Intertie. The Westside Intertie consists of two 500 kV lines from Ingledow to BPA's Custer Substation near Bellingham. The Eastside Intertie has two 230 kV lines. One line runs from Nelway to BPA's Boundary Substation. The second line, owned by TeckCominco and operated by FortisBC, is normally connected between Waneta Generating Station and Nelway, with the final section of the line from Nelway to Boundary open (e.g., not connected). The WECC-approved path rating from BC to the US is 3150 MW while the WECC approved path rating from the US to BC is 2400 MW.

In April 2008, the BCUC approved capital expenditures for a thermal upgrade of the 500 kV circuits of the Ingledow-Custer transmission tie, also referred to as the western tie of the BC-US intertie (Thermal Upgrade Project). The Thermal Upgrade Project will result in an increase in the south-to-north transfer capability of the BC-US intertie.

Sea Breeze Power Corporation is proposing to build a 49-km HVDC Light submarine cable with a planned rating of 550 MW across the Strait of Juan de Fuca, connecting Port 17 Angeles substation on the Olympic Peninsula in Washington State with Pike Lake 18 Substation near Victoria. Sea Breeze Power is currently planning the JDF project to come into service in 2010.

In addition to the Thermal Upgrade Project for the BC-US west tie and Sea Breeze Power project, the following is a list of interconnection studies carried out recently:

BCTC completed a joint study with AESO to examine the economic benefits from a second Alberta-BC tie. The study showed that the present level of interconnection between the Alberta and BC is among the lowest levels for two electric systems of comparable sizes. The report concludes there are future scenarios that warrant the development of additional intertie capacity. The report recommends that BCTC and AESO work with the Alberta and BC governments to develop business models that would result in an equitable sharing costs and benefits from additional intertie capacity.

A WECC Regional Planning Review process to investigate the feasibility of delivering renewable energy to northern California has been completed. The preferred transmission alternative, named the Canada-Northern California (CNC) line consists of a 1,500 MW, 500 kV AC line from Selkirk in BC to Oregon, and a 3,000 MW DC 12 line from Oregon to the San Francisco area. The target in-service date for the CNC line is 2016.

Proposed by TransCanada, the Northern Lights initiative would be a high voltage DC transmission path from northern Alberta to the US, crossing through the southeast corner of BC. To be completed by 2015 or later, this project may give BCTC an opportunity to expand intertie capacity with both Alberta and the US. This proposed project could transmit over 3,000 MW of power to Washington or California markets.

2.12 YUKON

At present there are no existing, committed or planned interconnections to other jurisdiction for the Yukon Territory.

2.13 NORTHWEST

At present there are no existing, committed or planned interconnections to other jurisdiction for the Northwest Territories.

2.14 NUNAVUT

At present there are no existing, committed or planned interconnections to other jurisdiction for the Nunavut Territory.

Figure 2-1: Existing Interconnection Lines Between Jurisdictions

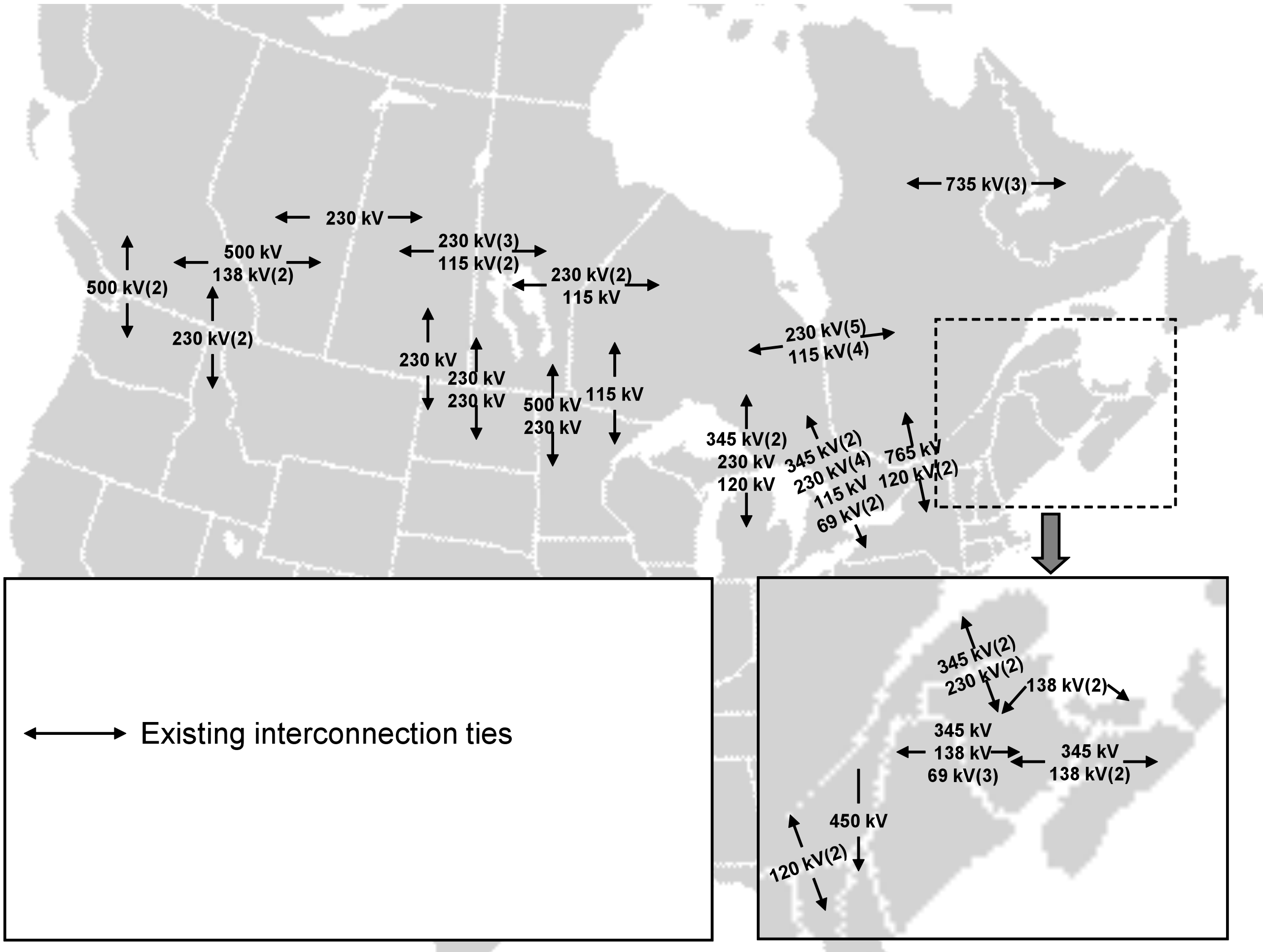


Figure 2-2: Existing and Committed Interconnection Lines Between Jurisdictions

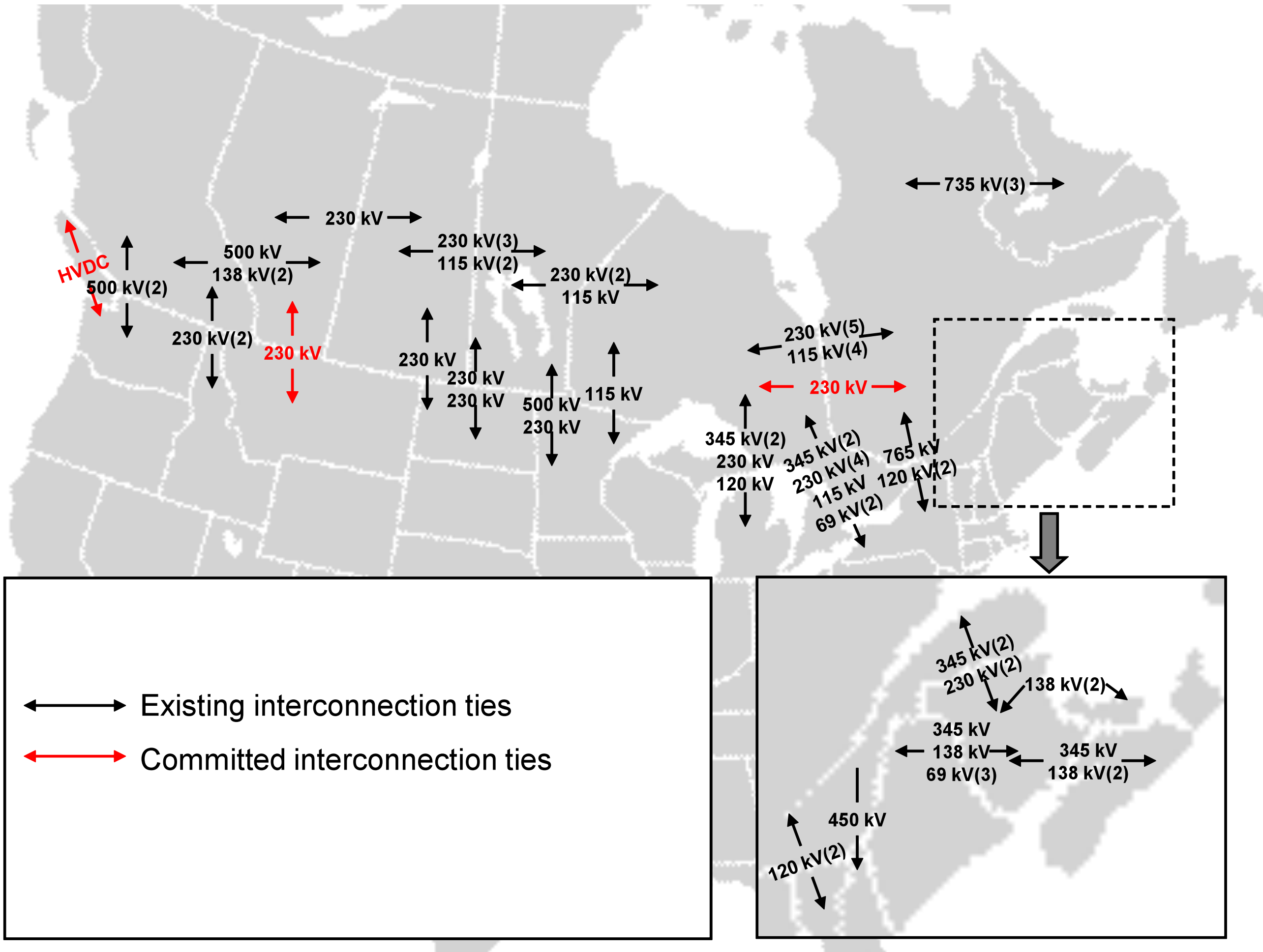
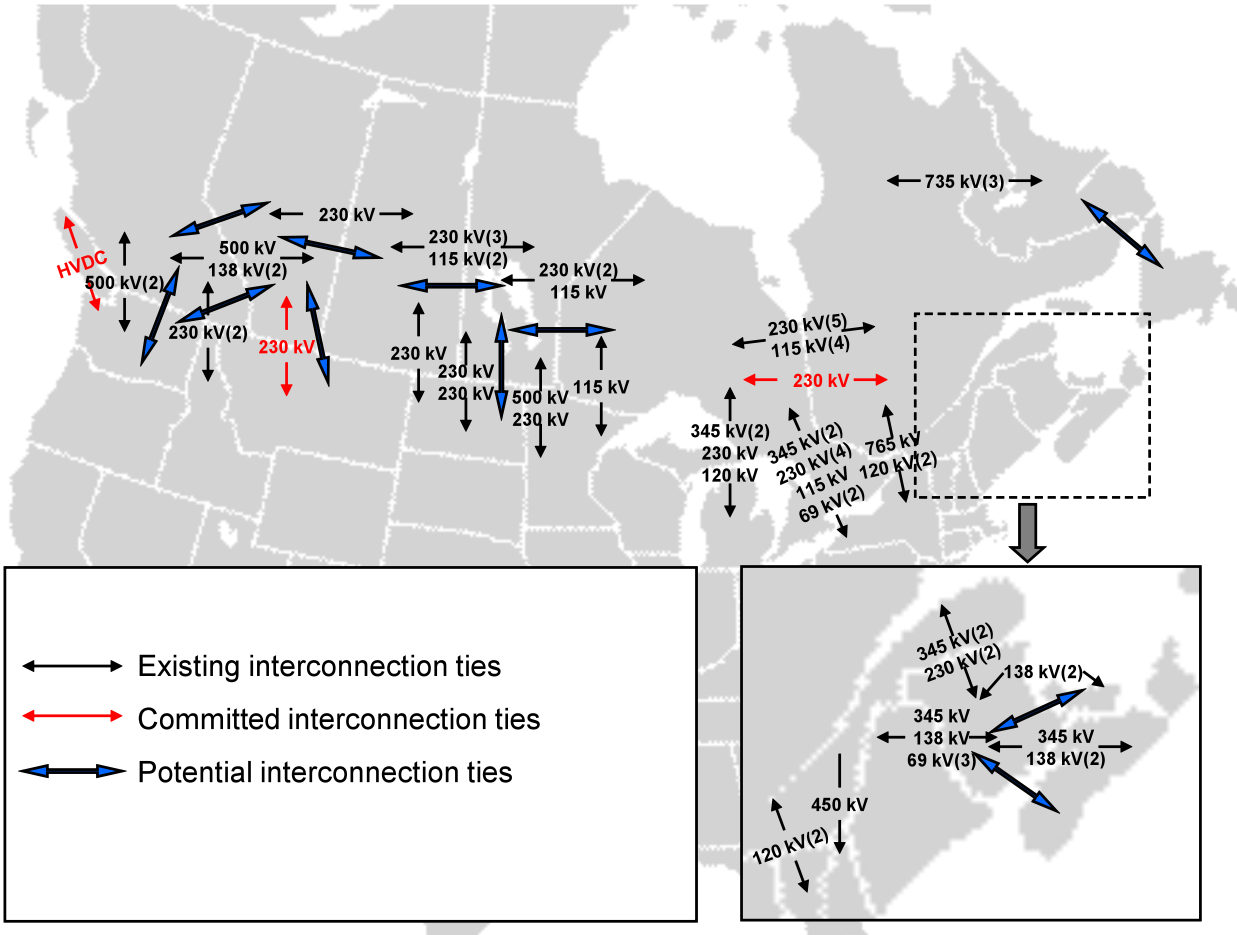


Figure 2-3: Existing, Committed and Potential Interconnection Lines Between Jurisdictions



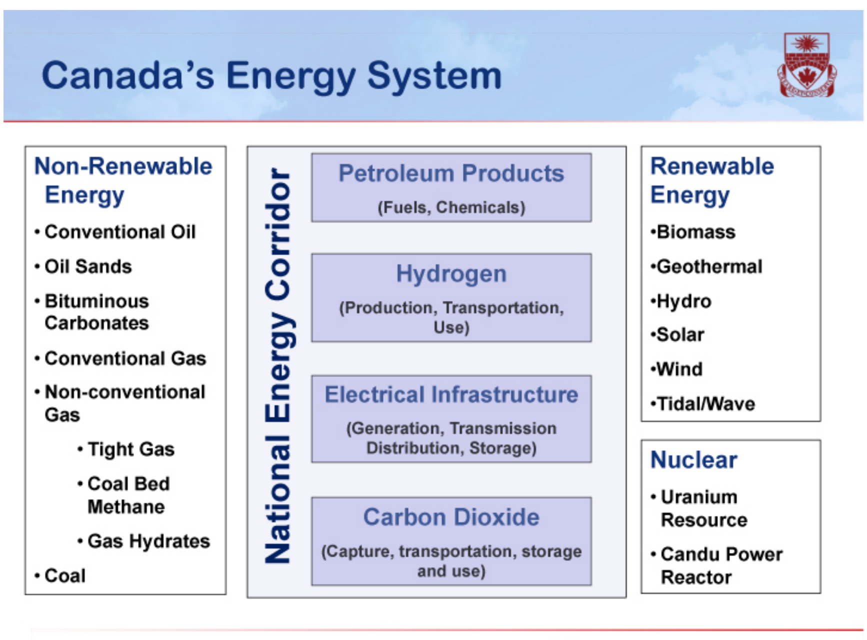
3. NATIONAL GRID – RELATION TO CANADA'S ENERGY CORRIDORS

3.1 ENERGY AS A SYSTEM

The belief that a systems approach will be required to capture the potential of Canada's energy endowment has been well accepted. The following extract from an Advisory Panel report is a recent statement of that need: -In its deliberations, the Panel viewed the Canadian energy economy as an interconnected system, containing large flows and conversions of energy, strong interdependencies between producers and users of energy, and significant exports. In recognition of this, our assessment takes a systems approach to energy technology and to the energy innovation system."[18]

What does a 'systems approach' mean, and how would it be developed and applied?

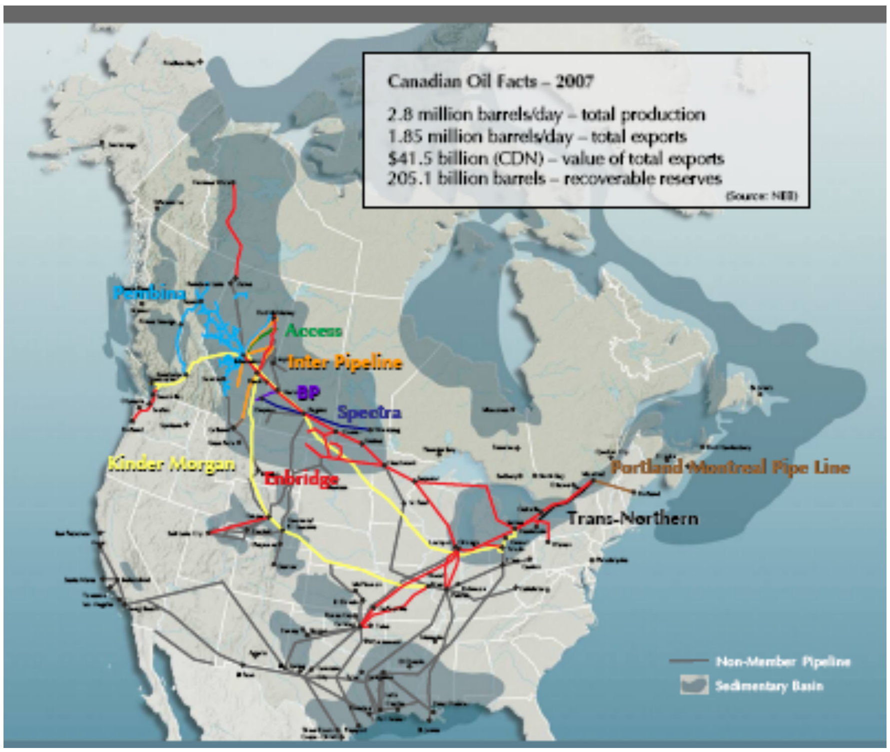
The following chart illustrates the breadth of the Canadian energy resource base and how it connects to the array of energy products and by-products that are produced from the raw resources, including petroleum fuel and chemical products, hydrogen, electricity, and carbon dioxide. These four commodities can be considered as part of an energy corridor, weaving its way across the country, highly interconnected and having different roles and importance in each region. The electrical grid becomes an important spine in this system, supplied by a combination of diverse base load generation facilities, supplemented by regional renewable energy sources.



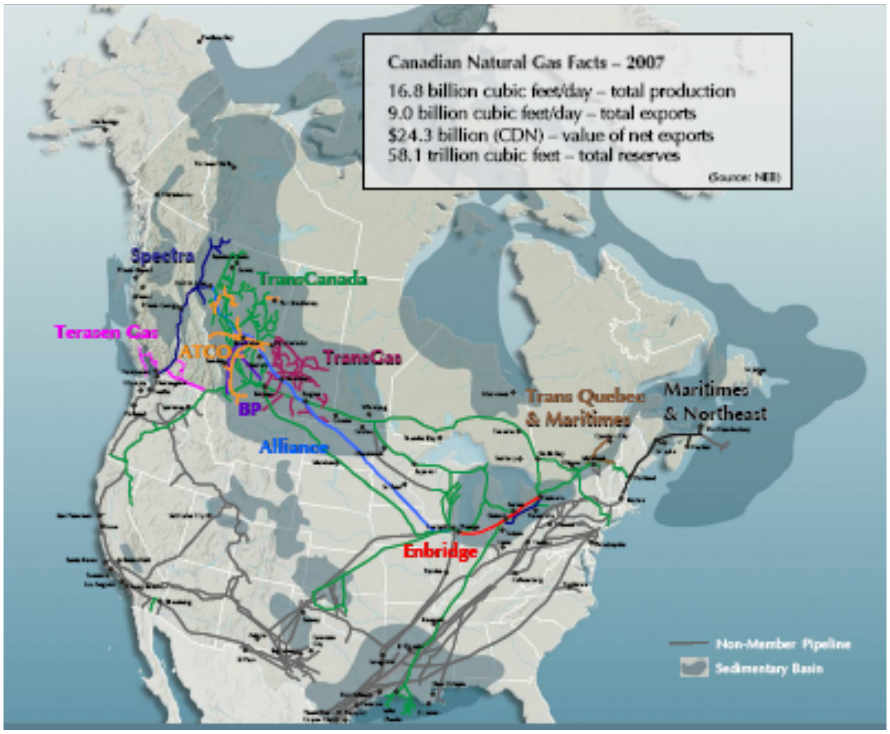
[18] Powerful Connections, Priorities and Directions in Energy Science and Technology in Canada, Report of the National Advisory Panel on Sustainable Energy Science and Technology, 2007

3.2 ENERGY INTERCONNECTIONS

Canada currently has a well developed and mature network for the movement of petroleum products, including oil and gas, as evidenced in following pipeline maps.



Canadian Oil Pipelines
(Information from the Canadian Energy Pipeline Association) (CEPA)



Canadian National Gas Pipelines
(Information from the Canadian Energy Pipeline Association) (CEPA)

In the electrical sector, Canada has more interconnections with the U.S. than it has between provinces.

Source: National Energy Board, Canadian Electricity Exports and Imports: An Energy Market Assessment, January 2003, p. 9.
The numbers indicate the voltage of the power lines from each province to adjoining provinces and the states. If there is more

Canada's Electrical Interconnections
Many North- South Interconnections provide export of 4% of our power to the U.S.

Canada also has many energy corridors where clusters of plants have benefited from the exchange of feedstocks, products and by-products. Two examples are described below.

Alberta Industrial Heartland (AIH), an industrial corridor running north-east of Edmonton, comprising a cluster of over 40 companies involved in the petrochemical, chemical and oil and gas industries with the capital investment approaching $23 billion. There is extensive interchange of products, including hydrogen, methane, ethane, ethylene, oxygen and carbon dioxide. Electrical cogeneration plants have a very high efficiency. The corridor is an integral part of the North American pipeline networks carrying oil, natural gas, ethane, and ethylene to processing plants and markets. A theme of the region is upgrading bitumen, with a plan to increase upgrading capacity from 150,000 bpd to 1.7 million bpd by 2017. The estimated capital expenditure for the area over the next decade is approaching $65 Billion.

The full expansion of all projects currently proposed for the Heartland region (7 bitumen upgraders plus other petrochemical and gasification facilities) would result in an increased electrical demand for the region of approximately 600 to 700 Mwh of capacity. The current electrical system is not designed to support this and, therefore, additional infrastructure will be required before development will occur. In discussing this matter with future developers, they have expressed concerns regarding the lack of electrical transmission infrastructure. What would be preferable would be a system, or at least firm plans for a system, to provide electrical supplies to these developments. Many of the regions in the world that compete with for these types of developments already have the electrical transmission systems in place and can boast a “plug and play” type of infrastructure to potential investors. On the other side of the equation, there is a large potential for the development of Combined Cycle Gas Turbine systems that would utilize syn-gas (a product of petcoke gasification). To make these projects a reality they would need a system to allow them to export their power to other projects sites within the Heartland or to export it to users outside of the Heartland area. There is thus an evolution in the development of energy corridors such as the Alberta Industrial Heartland. At an early stage, the availability of reliable competitive power will be a major attractor for new industrial development. At a later stage of development, the corridor may have excess power for export outside the corridor, from by-products and/or renewable energy projects.

Sarnia-Lambton Petrochemical and Refining Complex is a corridor of integrated petroleum and petrochemical industries, lying along the St. Clair River. North America’s first oil well was discovered near Sarnia 150 years ago, which led to the construction of one of Canada’s first oil refineries in the 1920s. The site was selected for the manufacture of synthetic rubber to support the war effort during World War II. Large pipelines were constructed to bring Alberta oil to Sarnia, leading to Sarnia becoming the country's largest and most diverse cluster of chemical, plastics, allied manufacturing, petrochemical, and research and development facilities. There is extensive exchange of products and by-products among companies, with a growing capability for electrical cogeneration. Advances in chemistry, biotechnology engineering, and environmental pressures are making it attractive to expand into renewable energy opportunities.

Within Sarnia-Lambton, a strategic initiative is underway to work with the traditional petrochemical and refining sector to facilitate development of existing and future investment opportunities in a sustainable manner. Within the regional complex, local companies are strategically marketing their plant sites to attract complementary manufacturing activities that can benefit through access to existing infrastructure, services and raw materials. Efforts are underway to facilitate new sectors that have a logical relationship with the community’s existing infrastructure, which has traditionally supported the petrochemical and refining complex and the agriculture community. The concept of the "Biohybrid Economy – merging the hydrocarbon based economy with the industrial bioeconomy – is strongly supported by the various community partners. Within the Biohybrid Economy, there is potential to replace or supplement materials currently based on hydrocarbons with those made from renewable resources – biofuels, renewable chemicals and biocomposites and bioplastics. There is also a strong focus on development of the Cleantech Sector (solar, wind, fuel cells, batteries, energy conservation).

For these strategic sectors, a key location requirement for the attraction of new investment is the availability of reliable and competitively priced electricity. With the considerable volume of local generation that is available, reliability is not an issue. However, the region is at a disadvantage given the higher pricing structure of the Ontario electricity market when compared to competing jurisdictions (Alberta, Quebec, U.S. Gulf Coast). Into the future, this disadvantage will increase further due to changes in the supply mix that are being driven by provincial energy policy.

A national electricity grid will assist Sarnia-Lambton to overcome this impediment to new investment if an economic mechanism can be developed that would provide more competitively priced power within the region. The traditional power generation sector offers significant potential for investment as Sarnia-Lambton has the attributes (large tracts of industrial land, large volumes of water and natural gas) to accommodate additional new electrical generation facilities. However, within Hydro One's high voltage transmission system there are capacity limitations that restrict the export of electricity out of the region and no plans are in place to address these limitations. A national grid will alleviate this barrier to new generation investment if it had the ability to export locally generated power.

The design of new and upgraded electricity transmission infrastructure should take into account the needs and potentials of Canada's energy corridors, as part of the value proposition. The economic envelope should encompass more than just the ROI of the transmission line itself.

3.3 PLACING THE ENERGY SECTOR IN THE CANADIAN ECONOMY

The concept of energy as an interconnected system is a concept that has not been followed in other sectors of the Canadian economy.

For example in forestry, in spite of being great hewers of wood and makers of paper products, Canada does not make chain saws or paper making machines, and we have lost much of our previous capability in the manufacture of value-added wood products.

In mining, Canada was a former leader in minerals processing technology but much of that capability has disappeared, as well as ownership of the industry.

In aeronautics, we were once a leader in fighter aircraft but with the cancellation of the AVRO arrow A huge pool of talent was lost to the U.S. and it has taken 50 years to regain a foothold in aerospace technology.

In the automotive industry, the free trade agreement with the U.S. led to a Canadian word class excellence manufacturing in quality and cost, but with limited design capability. With the current leadership that is being displayed at several levels, this will remain as an important economic sector but a world leadership position is not realistic.

The lesson from our experiences in these economic sectors is that although we have been blessed by having visionary leaders in the past, we failed to establish a capability across the entire production process. There is an opportunity in the energy sector to develop an integrated capability from resource harvesting to a fully upgraded stream of value-added products.

3.4 THE ENERGY SECTOR AND CLIMATE CHANGE

The global energy sector is the largest emitter of carbon dioxide and will be the first to feel the effects of carbon tariffs, whether they are applied as a carbon tax or as a cap and trade.

Canada's energy use per capita is higher than most of the developed nations due to our cold climate, large land mass and dispersed population. But Canada already has a very low carbon footprint in a sizable fraction of our electricity generation (hydro and nuclear). By integrating low and high GHG emitting energy sectors, the net emission per unit of energy produced would be considerably lower and would help avoid international carbon tariffs on energy exports. One prime example would be the Alberta oil sands where the existing carbon footprint could be reduced through energy integration as illustrated in the following table. This would convert 'dirty' oil into relatively 'clean' oil.

Energy Inputs for Oil Sand Production	Current Processes (high GHG emitters)	With Energy Integration (low GHG emitters)
Heat	Burning coke, resids, coal	Nuclear
Hydrogen	Reforming natural gas	Non-fossil electricity
Electricity	Burning coal	National grid powered by Hydro, Nuclear or Coal Gasification with CO2 capture and storage

NRCan has provided a clear description of how Canada's energy flows are integrated with our uranium, hydro, biomass, coal and petroleum resources feeding the electric power, residential, commercial, industrial, transportation and petrochemical sectors.[19] In the year of study (2002), Canada produced 11.91 exajoules of energy and released 531 megatonnes of GHG, or 45 megatonnes per exajoule. This could be a useful measure to compare the GHG intensity of the energy industry of different countries.

Jeff Rubin argues in 'Why Your World is About to Get a Whole Lot Smaller' that sustained high oil prices and the expected 'tariff' on carbon emissions will negate the lower labour costs of developing countries and will bring many manufacturing jobs back to North America. Being a leader in the production of low polluting energy may help Canada restore a leadership position in manufacturing and in energy intensive industries such as mining and minerals processing.

[19] Canada's Energy Flows – Natural Resources Canada, Detailed, 2002, Version 2

4. DRIVERS AND SHAPERS

The concept of a National Grid is an important part of the response to a number of emerging challenges and opportunities, including the trend toward renewables and changes in supply/demand in the North American market. In this section factors are reviewed which will shape the context for planning the system.

4.1 SUPPLY-SIDE ISSUES

Pace of Hydro Electric Expansion

Canada gets 57% of its electricity from hydro, and there are still significant opportunities for adding additional capacity. As part of an ongoing strategy to promote hydropower as a viable energy source, the Canadian Hydropower Association (CHA) identified the need to obtain an up-to-date and accurate picture of hydropower potential in Canada and commissioned a study which took place between August 2005 and February 2006. The study identified the total technical hydropower potential in Canada to be 163,173 MW, with more than half of the potential coming from Québec, Alberta, and British Columbia. The current hydro generating capacity is about 73,000 MW.

Table 4.1: Hydropower Generation: Present & Undeveloped Hydro Potential (MW)

Provinces / Territories	Present[20]	Untapped Potential [21]
Alberta	909	11,775
British Columbia	12,609	33,137
Manitoba	5,029	8,785
New Brunswick	923	614
Newfoundland & Labrador	6,796	8,540
Northwest Territories	25	11,524
Nova Scotia	404	8,499
Nunavut	0	4,307
Ontario	8,350	10,270
Prince Edward Island	0	3
Québec	37,459	44,100
Saskatchewan	855	3,955
Yukon	78	17,664
Canada	73,437	163,173

[20] Electric Power Generation, Transmission and Distribution – 2007, Statistics Canada
[21] Study of Hydropower Potential in Canada – Canadian Hydropower Association – 2007

Lower Churchill Falls – Newfoundland and Labrador. The existing 5,428 megawatt (MW) Churchill Falls Generating Station which began producing power in 1971, harnesses about 65 per cent of the potential generating capacity of the river. The remaining 35 per cent is located at two sites on the lower Churchill River, known as the Lower Churchill Project. The Project consists of two of the best undeveloped hydroelectric sites in North America: Gull Island, located 225 kilometers downstream from the existing Churchill Falls Generating Station; and Muskrat Falls, located 60 kilometers downstream from Gull Island.

Nelson River – Manitoba. The Keeyask station (formerly known as Gull) would have a capacity of approximately 695 megawatts and planning studies are continuing. Projected first power date is likely about 2018, but no final design or construction decisions have been made, and no environmental hearings have been scheduled yet; however, in February 2009 the Tataskweyak Cree Nation community voted in favour of participation in the project. The 1485 megawatt Conawapa project was initiated but postponed indefinitely in 1992 when Ontario Hydro elected not to purchase firm energy from Manitoba. Planning activities now underway are intended to allow for an in-service date of about 2021, but no construction commitment has been made and no environmental hearings are currently scheduled.

Small-scale hydroelectric facilities. These add about 100 to 150 MW to Canada's power supply annually. With over 200 active small-scale hydropower generation sites across Canada, the industry has world-renowned expertise and project development capacity.

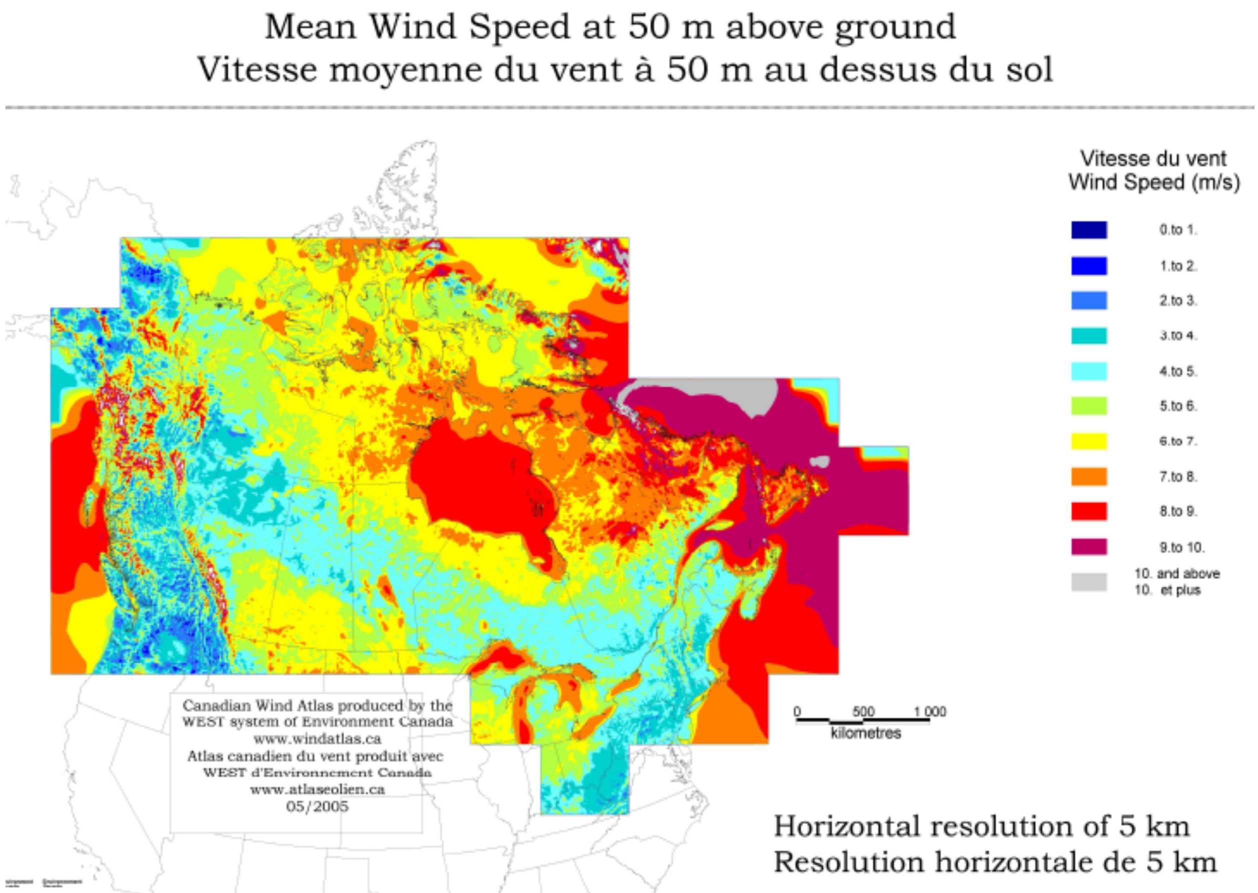
The environmental assessment requirements for regulatory approval and licensing for hydropower are extremely onerous. While steps are being taken to try to improve the process clarity and efficiency, the rigorous process ensures that all new hydropower projects have very low impacts. The pace of hydropower development will be dependent on improvements in the regulatory process, the development of inter-regional transmission and the implementation of a greenhouse gas system that will deliver a clear price signal for non-emitting resources (relative to fossil-fuel generation),

Two major factors that influence hydro power are the variability of flow and the potential for storage. Hydro and wind power are both affected by flow variability as discussed in the next section. The issue of storage is discussed later in Section 5.

Pace of Wind Power Expansion

The threat of climate change is adding urgency to increasing the share of renewable energy sources in the generation mix. Though wind is found everywhere there are regions where the wind conditions are far more favourable for power generation than others, which are illustrated in Figure 4-1.

Figure 4-1: Map of mean wind speeds in Canada



Given the relatively high cost of wind capacity there is a strong logic to concentrate investments where higher load factors can be achieved, at least for larger plants selling to the grid. Thus, like hydro, the best wind potentials are quite "site specific", with no relationship to where demand is located. This geographic "inflexibility" is quite different than the situation faced by thermal generation plants which are generally much freer to locate relatively close to the centers of demand. All over the world the longest bulk transmission lines are associated with large hydro projects. Something similar may happen with wind.

Another characteristic shared by hydro and wind is that the natural flow of the energy resource varies over time. These changes in natural flow are subject to varying degrees of uncertainty. Both the variability and the uncertainty of available power depend on the range of time you are considering – annual, seasonal, month, day, hour or minutes – and how far ahead into the future you are peering. Table 4-2 below compares the variability and predictability of hydro and wind power flows, between which there are important differences.

Table 4-2: Variability and uncertainty of natural energy flows of hydro and wind power

	Hydro		Wind	
	Variability	**Uncertainty**	**Variability**	**Uncertainty**
Short term (minutes / hours / days)	Hydro can typically be dispatched to match rapid fluctuations in demand.	Hydropower's dynamic response is superior to that of other sources of generation. The uncertainty is very small.	Significant oscillations hour to hour and day to day. Cannot be dispatched to match changes in load.	Considerable uncertainty, though forecasting techniques are improving
Medium term / seasonal (1-4 months)	While the variation in flows between seasons and years can be large, a significant proportion can always be counted on (dependable energy) while the non-firm remainder is variable. Depending on the magnitude of the reservoir storage the variability may be mitigated. Flows can be reasonably forecasted a few months in advance.	While there is considerable uncertainty related to the non-firm energy, it can be managed within statistical bounds. The dependable portion can be counted on.	Average variation in seasonal flow is usually significant. Sometimes very large.	Considerable uncertainty. Not yet researched the deviation around average seasonal variation
Annual / Multi year	Large variations in annual flows.	Great uncertainty.	Annual variation probably smaller than hydro; but little research.	Probably great, but not yet researched.

A big difference between hydro and wind is that hydro generation capacity is typically associated with storage capacity in reservoirs. The existence of a reservoir allows hydro to be dispatched to match rapid fluctuations in demand better than all other sources of generation. Even many run-of-the-river facilities have some flexibility in managing the instantaneous capacity. Even in the instances where there is no flexibility the flows of large rivers can be accurately predicted several days in advance.

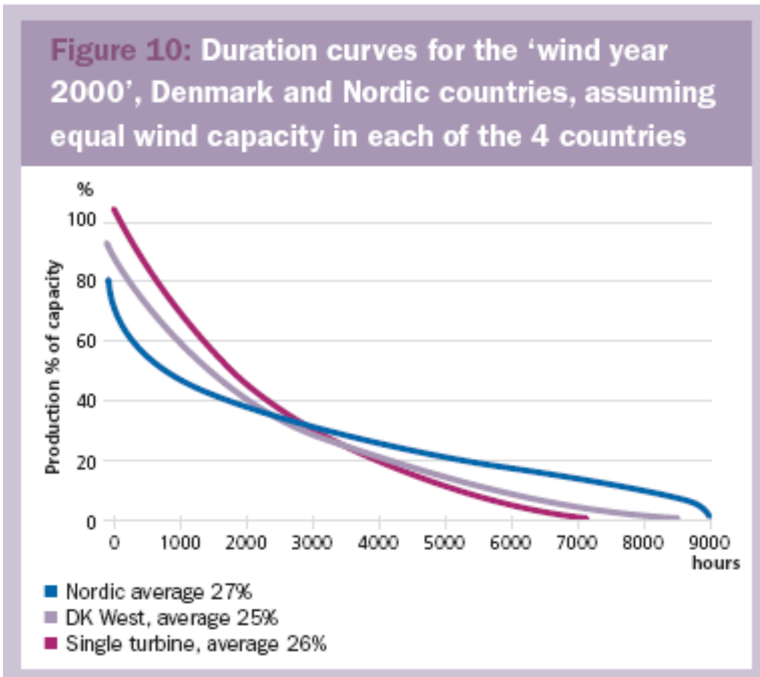
Beyond the flexibility offered by reservoirs, river flows (especially of larger rivers) can be accurately forecasted well in advance based on upstream flows. River flows do not vary much in the space of minutes hours or usually even days (except during flooding), Wind speeds are highly variable and because there is no mechanism for capacity storage or the comparable ability to forecast accurately based on upsteam flows, the capacity of wind generation is very uncertain.

The impact of the natural variations is amplified by the fact that the output of wind generators is very sensitive to wind speed. The energy available to be extracted from the wind increases with the cube of the wind speed. In addition, generation is cut off below a certain wind speed, say 3.5 m/s in modern turbines. It also is cut off above a given speed, about 20-25 m/s. Thus in a storm a turbine or entire wind farm may go from full power to zero very quickly. There are also low temperature cut-offs, typically at temperatures below -20°C.

The most important immediate challenge with wind has been to mitigate the short term fluctuations and uncertainties, which influence load regulation (seconds to minutes), load following (tens of minutes to hours) and plant scheduling. Of course, consumer loads are always changing. To understand the impact of a given capacity of wind energy on the dispatch of the remaining capacity on the grid, one should subtract the electricity generated by the wind from the load curve. From the changes in the net load one can calculate the "ramping" (up or down) required to follow the load. This ramping rate is a key factor in determining the reserve requirements of the grid's system and the costs of incorporating a variable resource like wind. If there is a positive correlation of the changes in wind output with those of consumer load (as occurs in Quebec with wind farms on the Gaspé peninsula), the net ramping can actually be reduced with wind, at least on average. However, situations with more extreme ramping requirements are still likely to be more common than would otherwise be the case.

Two broad approaches have been taken to mitigate the variation. One is to improve forecasting of wind speed and electricity generation at the site of each wind farm. This helps considerably with short term dispatch. The second approach involves linking wind farms over a broader geographic area. When the wind is low at one site it may be high at another. This reduces the oscillations as illustrated in Figure 4-2.

Figure 4-2: Load duration curves: single wind farm vs. Nordic average



Source: ref. 2

Increasing the catchment area to smooth out short term fluctuations in output is one example of a broader strategy called "complementation". Complementation has long been a key element of hydropower planning to respond to the seasonal and multi-year fluctuations of individual river basins. Again, when flow is seasonally low in one basin it may be high in another; or a wet year in one basin may compensate for a dry year in another. The linking together of river basins brings benefits in more firm energy (assuming the same river flows and storage capacities).

The same logic of seasonal and yearly complementation can apply to wind. It can also be applied to wind with hydro, or other combinations of naturally variable resources where they are relevant. A Canadian example of this complementation between wind and hydro is that average wind speed is highest in the winter, when river flows are lowest. Furthermore, hydropower reservoirs offer the opportunity to store the variable productions of wind energy and dispatch this energy when required most.

Complementation is a transmission-intensive strategy which could involve integrating quite distant regions, as occurs in Brazil, for example. At the same time, by looking at both wind and hydro together we may find geographic synergies. For example, northern Quebec and Labrador have excellent wind resources, not far from the hydro plants of the La Grande Complex and the Churchill River.

Most studies of incorporating wind potential treat that resource in isolation from hydro (or other variable renewables). They also usually cover areas too small to capture the full possibilities of complementation. One reason is that the analyses, in order to be practical, tend to accept the basic restrictions of the existing transmission system. A consequence is that the limits of incorporating wind in the generation mix tend to be met at quite lower rates of penetration.

However, if more stringent GHG emissions targets are to be met, wind energy may expand significantly. In that case, a new long distance backbone transmission system becomes more urgent and one should be prepared to think continentally and not just nationally (though this is already a big jump in both countries with their patchwork grid).

A question exists as to whether adequate analytical tools exist. As the USDOE's "Roadmap Study" (USDOE, 2004) observed: there is a "lack of analytical tools, as well as an organizational research infrastructure, to properly model the nation's entire electric grid…… Improved tools are also needed to simulate and analyze the alternative technology pathways for the national electricity backbone, including the design and costs and benefits."

Pace of Nuclear Power expansion and Siting Strategies

After years in the doldrums, nuclear power is experiencing something of a rebirth world-wide. This is in part a consequence of the logic of climate change. The emissions of GHGs resulting from generating electricity with nuclear power are indirect (mostly in the plant construction process) and small.

However, this nuclear renaissance is full of uncertainties, including about the full costs of generating power. To the uncertainties and risks must be added the relatively large size of individual plants, both in terms of MW installed and the investment required. Risks and lumpy size combine to make it hard to finance new nuclear capacity.

One approach to mitigating this problem, especially in the nearer term, is to spread the costs and risks among more than one investor. This parceling and diversification of risk can be done in various ways institutionally. In physical terms it is likely to mean a wider market area for the plant's output.

When we take a longer term perspective, another point emerges. Not only are individual nuclear plants usually larger than their fossil fuel counterparts, there is a greater tendency to cluster plants at specific sites. Future expansion is likely to reinforce this tendency – probably almost all new nuclear plants in the United States will be built at existing nuclear sites. In Canada the potential application of nuclear energy for Alberta is being investigated by a variety of groups, including the University of Calgary, the Petroleum Technology Alliance Canada (with industry and Government support), and the Alberta Research Council in collaboration with the Idaho National Laboratory.[22] Potential applications include using nuclear reactors to provide utility electrical operations, heat for the steam employed in the insitu thermal recovery of bitumen from oil sands and for the production of hydrogen and oxygen used by bitumen refiners.

Pioneering analyses in the 1970-80s led by Alvin Weinberg in Oak Ridge suggested that very substantial nuclear capacity could be added, overall, in the existing sites. At the time, such "nuclear parks" (on the order of 10 GW) were advocated in order to bring together the requisite know how to deal with low probability emergencies and to facilitate the safe handling of the flows of nuclear fuel and wastes. The fact that nuclear sites are, for all practical purposes, permanent structures is another factor leading to clustering.

[22] http://www.arc.ab.ca/documents/ARCINL-report-secure.pdf

The extent to which nuclear power grows and is concentrated in a relatively few clusters or “parks” will have important implications for the grid. Large clusters will require larger market areas, which has more regional than continental consequences. However, they will also require more robust connections with large sources of potential reserve capacity for reasons of reliability. This may involve going further afield.

Ability of Coal to Meet Environmental Requirements

There are two major challenges facing the use of coal for electricity generation:

Ability to convert from coal combustion to coal gasification technology which has the potential to produce a concentrated stream of carbon dioxide, more amenable to capture, and with the ability to generate hydrogen as a co-product, necessary for upgrading oil sands bitumen.

Whether carbon capture and storage and sequestration (CSS) technologies can be developed which are acceptable in terms of cost and reliability.

Coal has a vital role to play in the future of electric power generation in Canada, and the rest of the world. Coal has strong economic advantages over competing fuels because of its low-cost stable prices and large, proven reserves. In Canada approximately a fifth of our electricity is generated by coal. Alberta, Saskatchewan and Nova Scotia all depend on coal for 70 per cent of their needs, with coal supplying 25 per cent of Ontario's net generation. Internationally, dependence on coal is even more acute. In China, 81 per cent of electric power is fuelled by coal and in India that number is about 75 per cent. In the United States, coal accounts for 57 per cent of total generation. Compared to natural gas fired power generation, conventional coal plants have higher emission (CO_2, SO_x, NO_x, Particulates and mercury) and the challenge is to become cleaner by meeting or exceeding natural gas emission levels. Canada needs low-cost reliable power and must address the environmental challenges associated with coal-fired generation. The journey toward cleaner coal-fired power generation is driven by technological improvements and more stringent regulations around greenhouse gas and other air emissions. Capture and Storage of CO_2 (CCS) presents the biggest technical and economic challenge for future clean power generation. CO_2 capture centers on two technical approaches: Integrated Gasification Combined Cycle Power Generation (IGCC) with pre-combustion capture of CO_2 and various post-combustion CO_2 capture technologies including oxy-fuel combustion and various solvent based technologies such as amine and chilled ammonia. These technologies are at different stages of technical maturity and commercial demonstration in several countries. In Canada the challenge is to mobilize policies and formulate funding mechanisms to provide incentives and share the development and demonstration risks with industry.

Gasification and the associated shift reaction convert coal or any other low value carbon fuel in the presence of steam and oxygen into hydrogen and CO2. The hydrogen can be used in a gas turbine to generate clean power, refining oil, upgrading bitumen while the CO_2 can be captured and used in enhanced oil recovery, methane production from coal beds or permanently sequestered in deep geological formations. Gasification economics depend on feed/coal quality and little is known about gasifying low rank Canadian coals. Because gasification is a platform technology with applications not only in clean power production but also in the oil sands, refining, chemical and petrochemical industries it should become the focus of a national program to evaluate and improve existing technologies and to demonstrate the commercial readiness of specific Canadian clean power and poly-generation applications.

Recent federal and provincial government programs have recognized the importance of gasification and associated CCS technologies:

Epcor-AERI-NRCan FEED study for IGCC with CO_2 capture and storage

The Alberta Carbon Capture and Storage Fund

The City of Edmonton-AERI Gasification of municipal solid waste to produce biofuels, electricity and heat

The AERI Hydrocarbon Upgrading Demonstration Program which includes two next generation gasification technologies.

Accelerated Carbon Capture and Storage in Alberta, Interim Report, September 30, 2008

Constraints on Opening New Rights of Way

The real estate for installing power lines and cables is highly constrained, costly, and subject to time-consuming permitting processes. In the US it is estimated that 8-10 years are needed for planning, siting, and constructing new overhead transmission. As a result, a premium is placed on being able to expand carrying capacity without the need for new real estate or rights-of-way. This premium is a major driver for the development of new technologies for transmission (USDOE, 2004).

An example of the kind of challenge facing transmission investments is the resistance of some important environmental groups to the Sunrise Powerlink transmission project in southern California. This is a 123-mile line from the Imperial Valley to San Diego. Investments are planned in the Imperial Valley to generate energy from solar, wind and geothermal sources. The line has been approved by the California Public Utilities Commission, but has been challenged in a petition to the State Supreme Court. It is alleged that the transmission project would sacrifice sensitive public lands and vital habitat without any guarantee the line will reduce greenhouse gas pollution or lead to the development of significant renewable energy resources in the Imperial Valley.

There is a big divide among environmentalists, between those who are primarily concerned with achieving measurable changes in greenhouse-gas emissions and those who worry more about harm to natural habitats in general, whether caused by global warming or anything else.

Below as an illustration is a short philosophical statement by one environmental group – The World Wildlife Fund – in March, 2009:

“The environmental conservation movement has won many important battles, but it is losing the war. The capacity of the Earth to sustain life is diminishing progressively through the depletion of fisheries and forests, climatic disruption, soil degradation, chemical contamination, and the destruction of native ecosystems. The challenge of environmental conservation is to manage the Earth in its entirety. The sum of environmental conservation efforts worldwide must be sufficient to arrest and reverse the progressive erosion of Earth's capacity to sustain life. Anything less is failure.’

4.2 DEMAND ISSUES

Impacts of the "Smart Grid"

The term "smart grid", rather than being a name for any specific technology, represents a vision for a constellation of related technologies to digitally upgrade the distribution and bulk transmission grids. It involves the use of robust two-way communications, sensors and distributed computing technology in order to:

1. Permit a more interactive relation with the consumer, involving two-way flows of both information and energy:

   Dynamic time-of-use pricing of electricity with technology which permits the consumer to automatically control operation of key energy using equipment in response to price changes.

   Communications and controls which permit the utility (or dispatcher of the grid) to shut down specific equipment (load shedding) or activate storage and the consumer to be paid for this service supporting the grid.

   Interconnection of distributed generation resources (usually on the consumer's premises) and sale of surplus power to the grid under conditions which are safe.

2. Improve the monitoring of conditions on the grid in real time, together with advanced controls which enable more rapid diagnosis of problems and more precise solutions.

   Permit improved management of central generation assets, such as decreased need for peak capacity and central reserves.

   Anticipate and respond to system disturbances (self-heals).

   Improve maintenance of power quality and more rapid resolution of power quality problems.

3. Whenever outages do occur, to avoid cascading failures and limit the area (or number of consumers) effected; permit "islanding" whereby local distributed generation or storage can maintain essential services; more rapid recuperation of service.

Benefits of the Smart Grid. As a consequence it is expected that the "Smart Grid" will improve the reliability and safety of the operation of the grid as well as improve the productivity of the utilities' electricity generation, transmission and distribution assets. The latter would be due to the ability to: (a) "flatten the load curve" (e.g. through reduced power consumption during peak hours via pricing and targeted load shedding); (b) shed specific loads with minimal economic cost during supply-side emergencies; (c) access to distributed generation and storage technologies (which reduce the need for utilities' GT&D, given the same final consumption); (d) the ability to actually manage this much more complex new system.

A big benefit would be reduced requirements (relative to a base case) for investments in "big iron" or new generation, transmission and distribution capacity. There would also be benefits in lower line losses, fuel costs and costs of commercialization (e.g. billing) – not to mention lower costs to consumers resulting from power outages, which are estimated to be $ 100-150 billion/year in the US (USDOE, 2008).

The improvements in the productivity of the utilities' assets are often referred to as improving the efficiency of the system. This is certainly correct in a broad economic sense. However, it is important to realize that the direct impact of the Smart Grid on the efficiency of consumers' electricity use would be relatively very small. Technologies that mean you can switch off a refrigerator at times of peak load do not mean that that refrigerator will be an efficient model or will be properly maintained. To achieve greater efficiency of energy use requires a different suite of policies.

The impacts of the Smart Grid on consumers' energy efficiency will be more indirect. First, the information made available to consumers will make them more aware of where their energy costs are and of opportunities to reduce them.[23] Second, it enables some technologies which can improve the efficiency of the use of fuels, especially oil and gas. The two most obvious examples are small and medium CHP plants and plug-in hybrids.

Coming of age. Many elements of the Smart Grid concept have been put into operation in diverse countries over the years. For example, automatic meter reading with large consumers began in the 1980s and evolved into Advanced Metering Infrastructure. In the 1990s utilities' Demand Side Management (DSM) programs incorporated devices to adjust the duty cycles of equipment to avoid use during times of peak demand. The Bonneville Power Authority implemented the first Wide Area Measurement System (WAMS) in 2000 to monitor the transmission system in its area. However, the full set of technologies has yet to be put in place anywhere. Furthermore, most of the relevant products being commercialized today do not yet adhere to the requirements envisioned for the Smart Grid by diverse initiatives to establish the technological principles for the concept.[24]

With the prominence given to it in the economic stimulus legislation of the United States and other countries, the subject of the Smart Grid is now in intense ferment and there is much jockeying among players. There is both a technological dimension and a policy/regulatory dimension to the challenge. The latter is arguably the more difficult. It include issues such as rules for the cost recovery of new Smart Grid investments and the legacy systems made obsolete; dynamic pricing for consumers and the sale of energy by consumers back to the grid. Although the public resources being committed are substantial, private sector resources will predominate if the concept is to be effectively implemented over the coming decade.

A question of great relevance to this report is whether the Smart Grid would supersede the implementation of a new bulk transmission "backbone" to integrate the Canadian power system. After all, an explicit objective of the Smart Grid is to reduce the future need for GT&D investments.

Considering the challenges facing the power sector, especially those presented by the need to reduce GHG emissions, both strategies seem necessary. They are not mutually exclusive initiatives and they do rather different things.

[23] Another consequence of the Smart Grid is for prices to more realistically reflect costs, which is a *sine qua non* for motivating the economic optimization of energy use. Distortions in the average annual cost of electricity – as opposed to time of day costs – are relatively small in North America. The average annual cost is most important price parameter for energy efficiency, so the additional impetus for efficiency may be small in the USA and Canada. However it could be a factor in many emerging economies.

[24] These initiatives include EPRI's IntelliGrid Architecture, the California Energy Commission's Public Interest Energy Research program, the Modern Grid Initiative and DOE's GridWise program, as well as the mandates in the US Energy Independence and Security Act of 2007. See: Phillip Bane; *Scorecard for rating stimulus projects*; Smart Grid Newsletter, March 13, 2009. http://www.smartgridnews.com/artman/publish/commentary/SGN_Stimulus_Scorecard-536.html

As already discussed in other sections, a large increase in the use of variable renewable resources (especially wind and hydro) requires bringing electricity from areas where the resources are located to the centers of consumption – often long distances. It also points towards robust interconnections to exploit the potential for the mutual complementation of these variable resources. Ideally this interconnection would be at a continental scale. Clusters of nuclear power plants also point to stronger interconnections to provide a larger catchment area both for marketing power and for reserves.

The Smart Grid mostly helps to reduce the need for reserves and for peak load capacity (other things being equal). The improvements will mostly be within the provincial systems or electric reliability regions and the tendency may be for benefits to be concentrated relatively more at the level of distribution than of generation – that is, closer to the consumers. For example, in the United States, 10% of generation (and associated transmission) capacity is used less than 5% of the time, while 25% of distribution capacity falls in this category. In contrast, the transmission “backbone” serves to more closely link the existing provincial systems or reliability regions.

The Smart Grid increases the ability to respond to short-term variations in the load or power supply to maintain the system in balance. However, it does little to reduce the amount of electricity consumed each year. Nor does it do much to alleviate seasonal fluctuations in supply.

Much is made of the enabling of decentralized power generation, which seems to be seen in some quarters as a viable alternative to much of the projected output in centralized power stations. The most frequent references are to solar photovoltaic arrays in residences and businesses. Unfortunately, photovoltaics do not appear to be very promising in Canada. The main truly distributed generation potential is likely to be increased CHP (cogeneration) using natural gas, especially in smaller non-industrial plants (the potential for larger industrial CHP has already been largely exploited). While interesting, there is little indication that it will ever generate amounts sufficient to make a big difference in average CO_2 emissions per kWh. The same is true of small-scale hydro. Wind energy is often cited as another source of distributed power generation, but the evolution of this technology has gone precisely in the opposite direction, towards larger centralized projects which are often far from consumers. Thus, the Smart Grid does not seem to enable anything like sufficient distributed generation to eliminate the need for new generation capacity in central power plants.

In short, the Smart Grid is an important part of the response, but it is not the whole answer. Indeed, a “two-pronged” strategy seems to be the way policy is headed in the United States, where resources and priority are being directed towards implementing the transmission equivalent of the Interstate Highway system as well as to the Smart Grid. Of course, any new transmission “backbone” would incorporate the technology of the Smart Grid.

In some ways the policy challenge facing creation of a new bulk transmission “backbone” is rather similar to that confronting the Smart Grid. Both are “enabling investments” which change the game for other energy initiatives. In both cases, their economic potential cannot be realized without an integrated view of the diverse benefits, rather than considering only a single application or the perspective of a single market agent. Some of these benefits will only begin to emerge after the investment has been made. In addition, incremental projects need to be analyzed as part of an overall plan and not in isolation. Both require a strategic vision.

Possible Increased Use in Transportation, e.g. Hybrid Plug-ins

Until today, the energy supply for transportation has been almost completely outside the market for electricity. In the transport sector, only some railways consume electricity from the grid.

This historic segregation of transport energy from electricity may begin to change in the near future. The serious substitution of transportation fuels by electricity would represent an important structural change in energy markets with big implications both for energy security and climate change mitigation strategies, not to mention the power sector itself.

The stage has been set by the successful introduction of the hybrid electric vehicle (HEV) in the automobile market. The HEV has an electric motor which supplements the internal combustion engine. With the motor it is possible to use a substantially smaller IC engine and to operate it more often in conditions approaching those needed for efficient performance of that engine. For example, a 122 kW IC engine might be substituted by a 78 kW IC engine plus a 38 kW motor, together with a battery of 1.5 kWh (NREL, 2006). This concept also permits the use of regenerative braking, whereby the act of braking converts the car's kinetic energy into stored electricity instead of heat.

These characteristics permit the HEV to achieve better fuel economy than a conventional light vehicle of the same size and engine type – perhaps 25-30%.[25] After initial skepticism on the part of most automobile manufacturers, the HEV concept has been consolidated in the market. Most firms are bringing models to market and there are steady incremental improvements in performance.

The "plug-in" hybrid electric vehicle (PHEV) adds a larger battery and the possibility of charging it from the electrical grid. Because of the success of HEVs, electric machines and high-power storage batteries are rapidly improving in terms of cost and performance. Although HEV components are not optimized for PHEV applications, they do provide a platform from which HEV component suppliers can develop a range of PHEV components.

PHEVs are classified according to the distance they could travel on battery power alone, though of course the algorithms controlling their operation are not so simple. Thus a plug-in vehicle capable in principle of travelling 20 miles on battery power alone is a PHEV-20. One capable of travelling 40 miles is a PHEV-40, and so on.

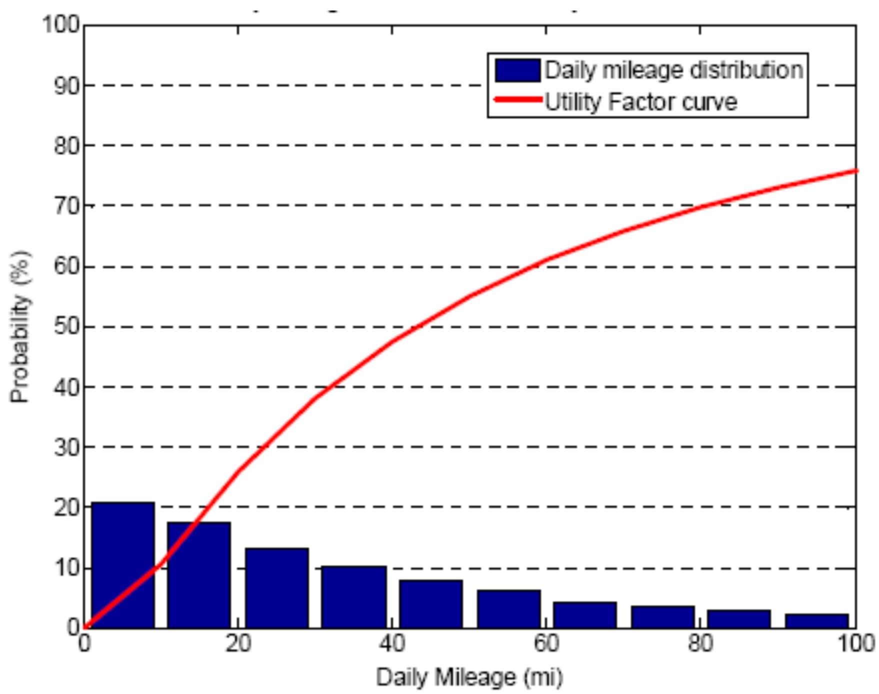
A factor favoring the deployment of PHEVs is that the cost of electricity is much lower than the cost of the fuel substituted. Roughly speaking, it takes about 12-13 kWh to substitute one (US) gallon of gasoline (3-3.5 kWh/liter), compared with an equivalent HEV. Someone jumping from a conventional vehicle (CV) to a PHEV would experience a lower kWh/gallon substitution coefficient, but some of that gain would be attributable to the basic HEV configuration and not the addition of "plug-in" capability. Current PHEV conversions are averaging around 4 miles per kWh.

Another favorable factor is that on an average day most automobiles aren't driven very far. Figure 4-3 shows the US vehicle daily mileage distribution based on data collected in the 1995 National Personal Transportation Survey. Half of daily mileages are less than 30 mi (48 km). The graph also shows the Utility Factor (UF) curve based on this data. For a certain distance D, the Utility Factor is the fraction of total vehicle-miles-traveled (VMT) that occurs within the first D miles of daily travel. For a distance of 30 mi (48 km), the utility factor is approximately 40%. This means that a PHEV-30

[25] This comparison is between HEVs and conventional vehicles with Otto cycle (gasoline) engines. Diesel engines in automobiles are more efficient than Otto cycle. No HEV so far uses diesel.

can displace petroleum consumption equivalent to 40% of VMT, assuming the vehicle is fully recharged each day.

Figure 4-3: Daily mileage distribution for US motorists



Source: 1995 National Personal Transportation Survey, as analyzed in Simpson, 2006.

There is no doubt that the concept of the PHEV has "sex appeal" at both a policy and popular level – a rare phenomenon this. It spawned a cottage industry to convert existing HEVs into "PHEV-2s". When GM began to develop the Chevrolet Volt, it was code named the "i-car" (Holstein, 2009). In the nearer term the PHEV is more flexible (and much cheaper) than a pure electric vehicle, while it does not require a complex new public infrastructure such as the use of hydrogen would require (or the exchange of recharged batteries at "gas" stations).

It is an incremental advance building from the new technology of the HEV, which permits a steady increase in the substitution of fuel by electricity as the technology matures. As observed at the beginning of this section, it opens a path which could be a major alternative to fossil fuel use in transport, without the severe resource constraints of biofuels.

This political "sex appeal" will probably be necessary for the PHEV to be a success in the near future. The cost of the increased battery storage capability is quite high with existing technology.[26] Reducing this cost and improving battery performance (energy stored per kg, power and durability) is a crucial priority. Even at relatively high prices of gasoline, the additional investment in a PHEV relative to an HEV is likely to have a rather long payback period.

[26] Different sources vary in their estimate of the current cost of battery storage – from US$ 800-1600 per kWh. As work progresses we will fine tune these estimates.

However, there are already important incentives provided by diverse governments and these may well grow. On the production side, for example, the development and manufacturing of advanced batteries is to receive US$ 2 billion in the US stimulus package. China is investing heavily in battery technology. On the consumer side, there are tax incentives for the purchase of PHEVs. As the experience with HEVs already suggests, many customers may be relatively insensitive to the payback time if they perceive that the new concept reduces environmental impacts in a significant way. That is, they are willing to pay an “environmental premium”.[27]

Once a critical volume of sales is achieved a virtuous circle of improvements can begin – again, rather like what has happened with HEVs themselves. The battery pack of Honda’s latest HEV model, for example, has 30% greater output and durability than that of the previous model, as well as fewer components. The learning curve is still steep.

Thus, it is early to be sure, but there is a real possibility that by 2020 a relatively large (and increasing) number of PHEVs may be sold each year, as well as some electric cars. The question of importance here is what might the consequences of opening this new market be for the electrical system and specifically the grid? Can this new demand overload the already stressed power system?

A point that jumps out of the exploratory studies published until now (Hadley & Tsvetkova, 2008; Lemoine et alii, 2008) is that the impact on the power system of even quite a large penetration of PHEVs could be rather modest relative to the electrical system as a whole. Indeed, some earlier analyses concluded that PHEV’s were almost a “free lunch”, in the sense that because of the generation and transmission infrastructure which is already in place, no additional investments would be necessary. For example:

> “The U.S. electric power infrastructure is a strategic national asset that is underutilized most of the time. With the proper changes in the operational paradigm, it could generate and deliver the necessary energy to fuel the majority of the U.S. light duty vehicle fleet.” (Kintner-Meyer et alii, 2007)

In order to visualize the possible impacts of PHEVs, consider the analysis published by Oak Ridge National Laboratory (Hadley & Tsvetkova, 2008). Here it was assumed that by 2020 PHEVs would increase to 25% of the sales of new light vehicles and that this proportion would be maintained through 2030. Thus, by 2030, about 25% of the automobile fleet would be PHEVs. It was further assumed that:

(a) the PHEVs would have a 20 mile “all electric” range (PHEV-20);

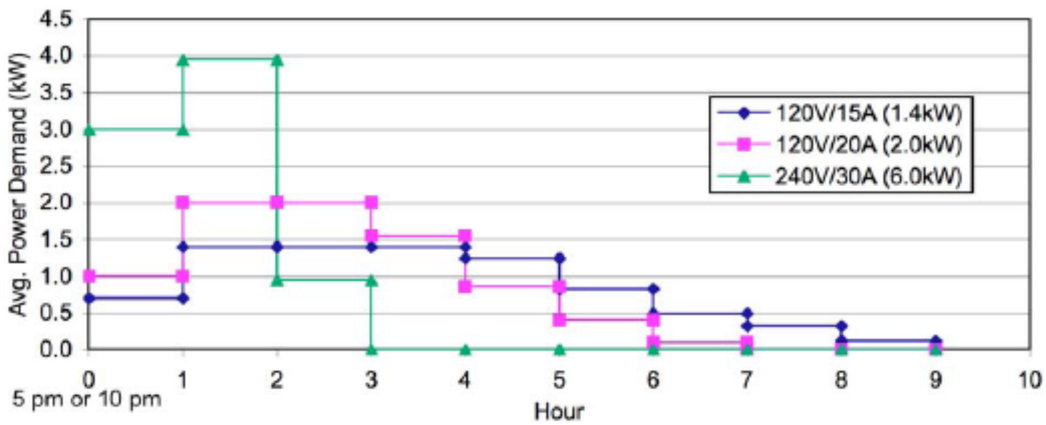
(b) there would be a mix of vehicle sizes: compacts and mid-size sedans (30% each); mid-size and full-size SUVs and light trucks (20% each);

(c) 80% of the battery capacity would be re-charged once a day.

[27] Unfortunately, there is a fly in the ointment in the US and other countries where fossil fuels generate a dominant share of electricity. A recent analysis for the US (Hadley & Tsvetkova, 2008) suggests that, relative to an equivalent HEV, a PHEV will slightly increase carbon emissions in 2030 – especially when recharging is done at night. Though there are responses to this “business as usual” scenario, it definitely raises a problem. Fortunately, in Canada, the situation is different, on average, because of the larger share of non-fossil fuel based generation – especially hydro. However, there are huge differences between provinces in the coefficient of CO_2 per kWh generated. In some provinces one could face a problem similar to that in the US.

Three different rates of charging were assumed: 1.4 kW, 2.0 kW or 6.0 kW. Finally, two scenarios of timing were tested: one beginning in the evening at 5 PM and the other beginning at night (10 PM). In each case, it was assumed that ½ begin charging at the specified time (5 PM or 10 PM) and ½ begin an hour later. Figure 4-4, shows the weighted average of the charging profile per vehicle.

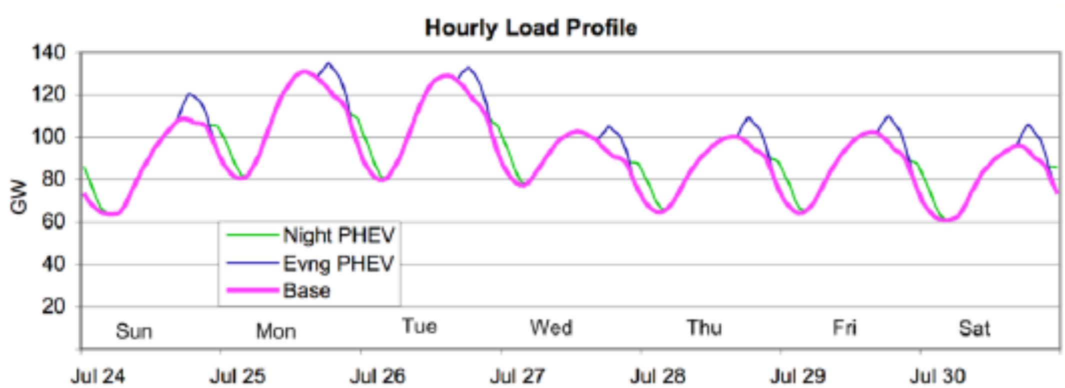
Figure 4-4: Weighted average charging profile with half starting one hour later



Source: Hadley & Tsvetkova, 2008

The impact of this scenario on the load curve of one electrical reliability region – ECAR[28] – is illustrated in Figure 4-5, an example which is quite similar to the simulations for other regions. In order to simplify presentation, only the 2 kW charging rate is shown for the two alternative charging periods (evening and night). The baseline from the load profile was developed from the projections to 2030 in the Annual Energy Outlook published by the Energy Information Administration of the USDOE.

Figure 4-5: Summer peak day in 2030 in ECAR with 2kW charging – hourly load profile



Source: Hadley & Tsvetkova, 2008

[28] East Central Area Reliability Coordination Agreement, which includes Michigan, Indiana, Ohio, West Virginia, Kentucky and Western Pennsylvania. This reliability area was subsequently redefined and is now mostly part of the RFC (Reliability First Corporation) region.

In energy terms, the impact caused by having ¼ of the car fleet as PHEV-20s is a pimple on the curves. It amounts to only 2.6% of the total electricity consumption projected for this reliability region, a value close to the US average (though different regions range from 1.2% to 5.5%).[29]

However, in terms of peak load the figure also shows that this “pimple” can be something of a problem, especially if charging begins in the evening, and also if higher kW chargers are used.

It cannot be comfortably assumed that people will only charge their cars during off-peak hours when it is convenient for the utilities. There must be clear price incentives and enabling technology at the consumer’s interface with the grid for this to happen. Putting this new interface in place will be a major challenge.

If the PHEV takes off it will provide a powerful impetus to accelerate the use of dynamic time-of-day pricing for low voltage and residential consumers, which is rare or nonexistent almost everywhere in the world today. At the same time it will motivate investments to increase the “intelligence” and interactivity of the grid’s interface with consumers, as well as new technology that is able to respond more quickly to changes in electrical properties of the lines in the grid.

Alongside raising challenges for the interface between the grid and the consumer, the PHEV may also begin to open new technological opportunities for balancing the grid’s supply and demand of electric power. Once many batteries are intelligently connected to the grid, it should be possible to provide a new type of fast-response reserve for the system. This could be increasingly useful in the context of a much larger future role for variable renewables such as wind and nuclear energy – neither of which have the flexibility for dispatch of most fossil fuel plants.

In short, the PHEV could be a quintessential new driver for the much discussed “smart grid”.

Potential for Increased Exports and International Exchanges of Electricity

Canada has exported electricity to the United States for many years. In addition, Canadian utilities participate in the North American Reliability Corporation (NERC) and there is routine exchange of energy in both directions to maintain reliability and reduce costs.

This international trade in electricity, though venerable, is quite small – at least from the perspective of the United States. As shown in Table 4-3, total imports of electricity from Canada and Mexico were about 1.2% of total electricity delivered to the grid in the US. Exports were somewhat smaller, so on a net basis the US imported 31 TWh in 2007, of which about ½ was firm power.

[29] One reason that the impact on the electric load is so small is that only 7-8% of automobile vehicle miles are effectively substituted by electricity. We assume that a PHEV-20 with an electric only range of 20 miles and daily recharging substitutes between 30 and 35% of gasoline (Kliesch & Langer, 2006) The substitution of gasoline depends not only on the storage capacity of the battery and the profile of daily driving distances, but also on the operational logic for the use of the battery. It is possible that more than ¼ of the fleet of cars might be PHEVs by 2030 or soon after. It is also possible that the all-electric range of the vehicles will be longer than the 20 miles assumed in the simulation. For example, the Chevy Volt is designed to have a 40 mile range. The longer “all electric” range implies about a 50% increase in the mileage per vehicle substituted by electricity. Then there are delivery trucks and urban buses. Thus it is not hard to imagine a situation where the “pimple” is substantially larger, if not in 2030, then soon after.

Table 4-3: US International Trade in Electricity, Recent and Projected to 2030 (TWh)
Source: US Annual Energy Outlook – 2009; Reference Case

	2006	2007	2010	2020	2030
Imports from Canada and Mexico					
Firm Power [a]	14	16	17	7	0
Economy [b]	29	36	29	31	46
Total	42	51	46	39	46
Exports to Canada and Mexico					
Firm Power [a]	3	4	1	1	0
Economy [b]	21	16	21	20	19
Total	25	20	21	21	19
Net Exchange with Canada and Mexico (exports = -)					
Firm Power [a]	10	12	16	7	0
Economy [b]	7	19	9	11	27
Total	18	31	24	18	28
Total US net generation to the grid	3906	4004	4042	4396	4859

[a] Firm Power Sales are capacity sales, meaning the delivery of the power is scheduled as part of the normal operating conditions of the affected electric systems.

[b] Economy Sales are subject to curtailment or cessation of delivery by the supplier in accordance with prior agreements or under specified conditions.

This small trade is not projected to grow. Indeed, imports and exports of firm power are to be phased out in the Reference Case. The stagnant international trade is consistent with the vision for trade between reliability regions within the US, which is also projected in the Reference Case as shown in Table 4-4.

Table 4-4: Gross Interregional Sales in the US, Recent and Projected to 2030 (TWh)
Source: US Annual Energy Outlook – 2009; Reference Case

	2006	2007	2010	2020	2030
Firm Power	123	125	119	82	38
Economy	151	117	208	232	186
Total	274	241	327	314	224

The stagnant interregional trade between reliability regions in the US in this scenario seems inconsistent with a large expansion of renewable energy, especially wind power. Indeed, though the projected expansion of renewables is significant (roughly a doubling until 2030) in the Reference

Scenario, wind accounts for less than 30% of expansion to 2030 and less than 20% (50 TWh) of expansion after 2010. Biomass and conventional hydro account for ¾ of the renewable expansion projected in that period (Table 4-5)

Table 4-5: Projected increases in renewable generation, by resource, to 2030 (TWh)
Source: US Annual Energy Outlook – 2009; Reference Case

	2007-2030	2007-2010	2010-2030
Conventional hydropower	53	22	31
Geothermal	7	3	4
Biomass & municipal waste	199	23	176
Solar	21	3	19
Wind	98	48	50
Total increase in the period	379	99	279

As a consequence, the lion's share of expansion in the US continues to be with fossil fuels, as shown in Table 4-6.

Table 4-6: Projected increases in generation, by resource, to 2030 (TWh)
Source: US Annual Energy Outlook – 2009; Reference Case

	2007-2030	2007-2010	2010-2030
Increase from fossil fuels	518	-41	559
Increase from nuclear	101	3	98
Increase from renewable	379	99	279
Total increase in the period	997	61	936

Of course, the Reference Case does not represent the new policies and priorities of the Obama Administration, but it shows the tendencies as of its beginning. Not surprisingly, CO_2 emissions are projected to grow substantially. Table 4-7 provides a summary.

Table 4-7: Projected changes GHG emissions from energy 2030 (million metric tons)
Source: US Annual Energy Outlook – 2009; Reference Case

	2007	2030	% Change
Total CO_2 emissions	5991	6414	7,1%
CO_2 emissions from direct use of fuel	3557	3685	3,6%
Of which: CO_2 emissions from transport	2009	2075	3,3%
CO_2 emissions from generating electricity	2433	2729	12,2%
CO_2 emissions per GDP (10^3 metric ton per 10^9 \$ GDP)	520	319	-38,7%
CO_2 emissions unit of electricity (ton per GWh)	585	530	-9,5%

Linkage to New US East-West Grids

As just observed, the United States, somewhat like Canada, currently has a patchwork of regional grids, between which exchanges are quite modest. A policy to significantly expand renewable energy in the generation mix, especially wind power, would increase these regional exchanges. An illustration of this shift is shown in the conceptual transmission plan to accommodate an expansion of 400 GW of wind energy prepared for the USDOE (Figure 4-6). The proposed high voltage backbone is a matrix, with strong new East-West and North-South linkages. The development of Canada's own transmission backbone would seem to follow a similar logic.

Figure 4-7 illustrates Brazil's grid (as projected for 2017), and is a less hypothetical example of a grid shaped predominantly by renewable energy supply from hydro. Unlike Canada and the United States, Brazil has a true "national grid".

Figure 4-6: Conceptual transmission plan to accommodate 400 GW of wind energy (AEP 2007)

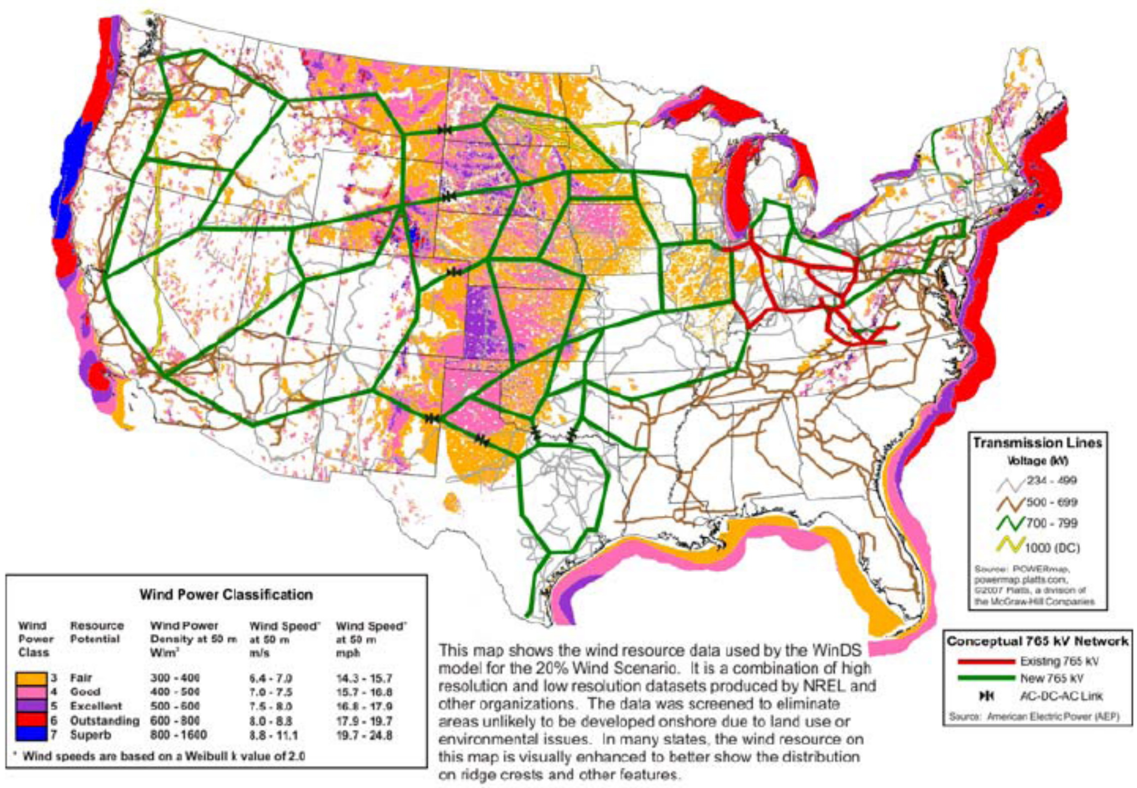


Figure 4-7: Brazil's national grid (as projected for 2017)

References:

USDOE; The Smart Grid – An Introduction; Report prepared for the US Department of Energy by Litos Strategic Communications under contract DE-AC26-04NT41817, 2008

5. ENERGY STORAGE TECHNOLOGIES

5.1 INTRODUCTION

Canada is a large, industrialized, sparsely populated country with an extreme seasonal climate. The population largely resides in four broad, yet concentrated urban areas: the Golden Horseshoe (Southern Ontario); Montreal and environs (Southern Quebec); Lower Mainland and Southern Vancouver Island (Southwestern British Columbia); and the Calgary-Edmonton Corridor (Southern Alberta) as shown in Figure 5-4. Stretching more than 1,000 km, the Quebec-Windsor axis is home to more than 50% of the country's population and is Canada's most industrially concentrated region. In contrast to these densely populated, industrialized energy load centers, the country's vast land mass provides bountiful natural resources, especially valuable energy sources. These resources supply the Canadian electrical grid primarily with hydro (58%), coal (19%) and nuclear (12%) – with the balance attributable to natural gas, fuel oil, and renewables[i] (Figure 5-1).

Hydro power capacity, which is well suited for both base loads and peaking demands, dominates in British Columbia, Newfoundland and Labrador, Manitoba and Quebec (with Quebec producing more than 50% of the country's hydro power). For the most part, the country's hydro resources are remote relative to the load centers. Coal-based power, which is mainly suited for base-load supply, is heavily generated in Alberta, New Brunswick and Nova Scotia. Ontario relies on a mix of nuclear, coal and hydro.

Canada, like much of the industrialized world, retains high use of our energy resources, as characterized by daily, weekly, and seasonal cycling of electricity consumption as presented in Section 2. This costly requirement of supporting large variance between peak and base demands is a carry-over from the abundant energy era which relies to a considerable degree on our "ponded" hydro sources and regrettably also on costly spinning reserves derived from fossil fuels – mainly natural gas.

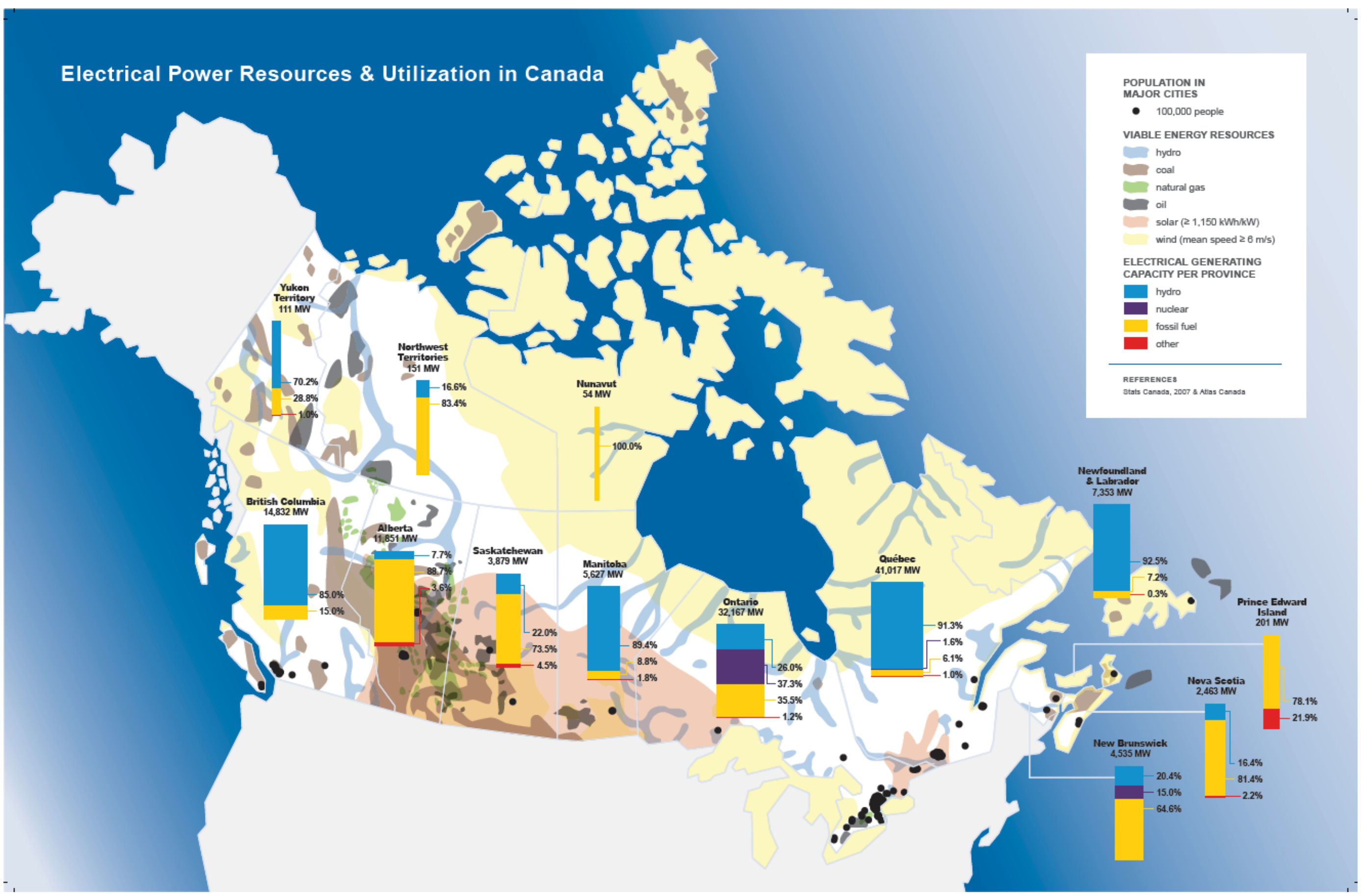
A number of important approaches are needed for increasing the power supplies to the industrial areas and equally important for reducing peak demands from daily demand cycles. These include:

1. Massive shift to sustainable, renewable energy sources from the sun – further exploitation of hydro and the rapid development of wind and solar (the latter being the exciting, new "dance-partners" of hydro).
2. Large shifts in the regulations, commercial methods and markets for distributing and pricing electricity:
    a. The Smart Grid for optimizing distribution and pricing to minimize daily variation.
    b. New, energy-efficient equipment and appliances to enhance energy efficiencies and reduce peak loads.
    c. Developing large, discretionary (or interruptible) power users that can absorb or shed electrical loads as needed; such as automotive battery charging; electrical production of intensive chemical feedstocks (e.g. hydrogen for fertilizer); electric metallurgical furnaces; etc.

3. The development and judicious expansion of energy storage systems to enable levelling of the electrical peak cycles and to bolster the expansion of modernized base-load generation (coal and nuclear) as well as to facilitate the penetration of renewable energy sources into the grids.

   Focusing on the third approach, integration of electrical energy storage has great potential for supporting the power grids in Canada. Of the nine electrical storage technologies assessed here, two have long-standing maturity in providing the large capacities required for the central grid service: traditional hydro reservoir water storage (ponding) and pumped hydro storage. Two newer technologies have meaningful-sized demonstration facilities operating: compressed air storage with electricity recovery using gas turbines (CAES) and molten salt storage of captured solar energy with electricity recovery via steam turbines. Two older energy storage technologies that have been used successively in other applications are examined for back-up of the electrical grid: batteries and hydrogen. Also, superconducting magnetic energy storage and electrical capacitors, although fairly new, offer promise. Finally, vehicle to grid completes the assessment as it is viewed as offering substantial potential. Results of the assessment are summarized in a matrix table that evaluates the major attributes and shortcomings of each technology.

Figure 5-1: Overview of Canadian population density, provincial electrical generating portfolio and resource siting



5.2 TRADITIONAL HYDROELECTRIC STORAGE

Traditional hydroelectric power generation is one of the oldest and most concentrated forms of renewable energy derived from the sun. The importance of hydroelectric power in the Canadian context is evident in the availability and exploitation of this resource. Canada is the second largest producer of hydroelectricity (after China) and is responsible for approximately 12% of world-wide hydroelectricity generation[ii]. There are over 60 hydroelectric stations in Ontario alone and 58% of Canada's electricity is generated by hydroelectric installations, as shown in Figure 5-4. Many northern sites are still available for exploitation[iii]. Canada is blessed with bountiful hydroelectric resources; in fact, the electricity age was ushered in at Niagara Falls. This is an enormous advantage in our efforts to provide affordable and clean energy.

The suitability of this resource for energy storage is just one of its many advantages.

Principles

The process of building dams to harness the inherent power in natural waterways also enables the storage and use of water flow for other vital applications, including:

- Irrigation for agriculture;
- Water supply for industrial applications; and
- Potable water supplies for the population.

All of the above are essential services for society as a whole and are all interconnected in their usage. Poor irrigation will affect the well-being and supply of food to the general population and in turn affect industry and its need for water and power. The use of hydroelectric dams allows for the synergistic integration of all of these numerous uses of water, a contribution other power generation sources are incapable of providing.

Although there exist a myriad of hydroelectric installations of all sizes, the larger projects are eminently suited for the massive storage of energy needed for Canada's national grid projects, such as the wide adoption of wind power and the installation of modern base-load nuclear reactors.

Hydroelectric installations can be used to store energy by reducing the normal flow of water downstream. Flowing water is used to generate electricity, and when it is held back, the energy is stored in the upper reservoir, behind the dam. This allows for more generation later, as more water is available to be released downstream. This practice is referred to as "ponding" and is well-suited for quickly responding to variations in demand load. It is not a particularly novel idea, as the reservoirs behind these dams have traditionally been used to store energy and even-out the annual variation in water flow; Northern Canada's rivers flow strongly in the spring and summer and much slower in the fall and winter.

The facilitation of wind power is another important opportunity for traditional hydroelectric power. Excellent wind power potential exists in the major river basins of Northern Canada, coinciding with the large potential for hydroelectric power (see Figure 5-4). Besides providing energy storage to level the variation in wind power generation, hydro also helps to spread the high capital cost for the long, expensive power lines needed to transmit the hydro and wind power produced in the North to the major population centres in the South. This would also facilitate the development of wind installations on route.

Power, Efficiency, and Economics

The power rating of a traditional hydroelectric installation depends heavily on the topography and climate at the installation site. In Canada, hydroelectric sites are as large as 5,600 MW (Robert-Bourassa) and 5,400 MW (Churchill Falls). The largest station in the world, the Three Gorges Dam, in China, has a power rating of 18,300 MW. There are also numerous small-scale hydroelectric projects as small as 1 MW.

The efficiency of a hydroelectric plant is determined to a degree by the efficiency of the power generating equipment. The typical over-all efficiency of a plant is approximately 80%. It should be noted that a traditional hydroelectric plant is more efficient than a pumped storage plant due to the absence of pumping which decreases system availability and introduces inherent inefficiency.

Due to the massive size of the large northern hydroelectric installations, the capital cost is usually immense. This cost is very dependent on topography and access to power transmission lines. The cost is also dependant to some degree on addressing the environmental concerns associated with alterations of the waterway's ecosystem. It is recognized that the environmental aspects of hydro dams and storage reservoirs must be mitigated by thorough consultation, design, and the needed provisions. However, when compared to competing technologies, such as coal and nuclear, these concerns are better known, quantifiable, and less costly.

It is important to note that while the initial capital cost is high for hydroelectric installations, on the basis of energy provided and available storage capacity, the per kWh cost is low. The estimated capital cost of current hydroelectric projects is in the 2,500 to 4,000 USD/kW range[iv]. With the ability to discharge at full power for hours, this cost translates to as low as $100 USD/kWh of storage capacity.

Applicability

From the above outline, the advantages of hydroelectric power are evident. Its applicability as energy storage for a national Canadian grid is recognized in the fact that the technology is so ubiquitous to the landscape and that it is inherently effective and efficient at storing energy for later usage. Of all of the technologies discussed here, hydro "ponding" is the most widely applied currently and, with good reason, the most successful. The reasons for this are outlined in the Scorecard/Summary section of this chapter, where the benefits of the technology are assessed more quantitatively.

5.3 PUMPED HYDROELECTRIC ENERGY STORAGE

A pumped storage facility creates potential energy by pumping and subsequently storing water at a higher elevation. The water is later passed through hydro turbines to generate electrical power. Pumped storage is a well proven technology that was first commercially utilized in Europe prior to 1900. Growth in pumped storage development proceeded rapidly on a worldwide basis, particularly in the last half of the 20th century. Today there are 39 operating plants in North America, including one in Canada.

Principles

A pumped storage facility includes upper and lower reservoirs, a pumping and generating plant, and interconnecting water conduits. The upper and lower reservoirs can be artificial or natural reservoirs with the lower reservoir often located on an existing waterway. There are also concepts and preliminary designs where the lower reservoir is an abandoned underground mine or an underground excavation made specifically for the project. Pumped storage can also be combined with conventional hydro generating plants where, in addition to pumping, there is natural inflow into the upper reservoir (ponding, as discussed above). The amount of energy stored is proportional to the volume of the upper reservoir and the difference in elevation (head) between the upper and lower reservoirs.

Early pumped storage machinery had separate pumps for storing energy and turbines for generating power. Present day pumped storage facilities generally have reversible pump-turbines, where the hydraulic machine rotates in one direction for pumping and in reverse for generating.

Pumped storage plants operate on daily, weekly or even seasonal bases, the difference being the size of the upper reservoir. Weekly cycles differ from daily cycles in that the upper reservoir is not refilled daily, and is progressively drawn down during the week followed by complete refilling on the weekend. With seasonable storage the reservoir is filled and drawn down over long periods of time, generally on an annual basis.

Power, Efficiency, and Economics

Plants up to 2,700 MW maximum power are in operation. Plant size is generally limited by physical characteristics and topography of the site (head and feasible reservoir size). Pumped storage plants generally have a capacity factor range of 7% to 12% [Capacity factor refers to the percentage of total time a plant is generating electricity]. Cycle efficiencies are between 68% and 74% for plants constructed between the 1960s and 1980s and 72% to 78% in more modern plants.

Pumped storage plants have long operating lives with overall lifetime often exceeding 75 years. The overall cost of a pumped storage plant is site specific but generally in the 1,200 to 2,000 USD/kW. Annual operating costs are typically 0.7 ¢/kWh to 2.0 ¢/kWh, excluding the cost of pumping energy.

State of the Technology

The technology used in pumped storage is proven and mature and is being gradually advanced and improved. Some notable recent advances in pumped hydro storage include: reversible pump-turbines, larger capacities, and efficiency improvement. The concept of underground pumped storage is also currently in development and has some attractive features for future deployment.

The major pump and turbine designers with a presence in Canada are: Alstom (France), Hitachi (Japan), and Voith Hydro (Germany) while Toshiba (Japan) and Andritz Hydro (Austria) are also important international companies. The construction of plants is performed by major infrastructure, engineering, and construction companies. For example, the major companies with experience in Canada are: Bechtel (US), Hatch (Canada), Peter Kiewet & Sons (US), SNC-Lavalin (Canada).

There are several hundred pumped storage systems in operation around the world. The first and only Canadian operation is the 174 MW Sir Adam Beck, Ontario, facility built in 1954. The highest capacity plant in the world is the 2,700 MW plant in Batch County, Virginia, US, built in 1986.

Applicability, Opportunities, and Limitations

Pumped storage can be utilized in a variety of electrical grid configurations including: multiple regionalized grids, a large central grid with long-distance distribution, and a hybrid system of the two. Pumped storage plants have excellent controllability and can improve grid stability and flexibility. Pumped storage plants are relatively large in capacity (>300 MW) to reduce unit capital costs by taking advantage of economies of scale. Therefore, depending on grid capacity, pumped storage plants may not be suited to small regionalized grids.

Pumped storage units have excellent controllability. Some important aspects of pumped storage plants are the “secondary” benefits that they offer, including: standby or reserve capacity, spinning reserve, and frequency regulation. Pumped storage plants are also known for high reliability with overall availability, including forced and planned outages, in the 90% range.

Location of pumped storage sites is limited by specific topography where sufficient head is available. The pumps used can have a fixed power input which makes it difficult to link directly with variable power sources such as wind turbines. Location of the reservoirs can also cause environmental concerns dealing with watersheds and aquatic life. There have been recent developments to reduce these limitations. Increased head and improvements in cycle efficiency reduce plant capital and operating cost. Underground pumped storage may give more flexibility in site location and less environmental damage. Furthermore, variable speed motors have been developed to better deal with variable sources of power.

It should also be noted that hybrid traditional/pumped storage plants do exist. In such a case, pumping capability is added to a traditional hydroelectric plant, so that during the filling of the upper reservoir, not only is natural water flow used, but also pumping from the lower reservoir.

5.4 COMPRESSED AIR ENERGY STORAGE

Compressed Air Energy Storage (CAES) involves storing energy as compressed air underground and retrieving that energy by heating the compressed air with natural gas and generating electricity via gas turbines. The CAES concept was first discussed in the mid-1970s. The first plant was constructed in Huntorf, Germany in 1978 and a second plant was built in 1991 in Alabama, US. Since then no new installations have been built, but the recent interest in renewable energy and energy storage technologies has renewed investigations into CAES technology.

Principles

Before compressed air is stored underground, CAES uses a system where compressors are equipped with inter-coolers and after-coolers (heat exchangers) to remove the majority of heat generated during compression. Cooling the compressed air also greatly increases the capacity of the storage tank or cavern. The removed heat is discharged into the atmosphere with cooling towers. The air from the after-coolers is stored in a pressure vessel, typically a deep cavern. During the generation phase, air is removed from the cavern and heated to the necessary temperature using natural gas in a combustion chamber. The heated air then drives the turbine generator(s). A CAES system utilizing heat recovery has also been studied. Heat produced during the compression phase would be stored and used to reheat the air as it is removed from the underground caverns prior to being introduced into the gas turbines during power generation.

The compressed air is usually stored underground in geological formations such as: solution-mined salt caverns in salt domes or bedded salt, hard rock mined caverns, aquifers, and abandoned gas and oil wells. The depth of the formation that is selected for a CAES cavern is the determining factor for the acceptable storage pressure. In order to reduce the size of the cavern the ideal storage pressures are in the range of 6,200 kPa to 7,200 kPa (60 to 70 bar).

Power, Efficiency, and Economics

The maximum power rating for a CAES plant is dependent on the depth and volume of the storage cavern versus the installed storage capacity. The plant in McIntosh, Alabama, US, has an installed capacity of 110 MW and 26 hours of storage with a cavern size of 538,000 m^3. The 670 m deep Summit mine in Ohio, a proposed location for CAES, has a volume of 9.5 million m^3 and is capable of having a station capacity of 2,700 MW for 10 hours. For currently-operating equipment, 1.33 MW of generation are returned from the grid for every 1 MW that is used in the compression phase. In addition, 3,900 to 5,400 Btu/kWh of heat are added in the combustion chambers to give a round-trip efficiency of 52%. Storage of compression heat for use in the generation phase has been studied and would improve cycle efficiency.

The capital cost is highly dependent on the cost of developing the underground works. The current costs for development of a CAES site are estimated to be 1,500 USD/kW for a solution-mined cavern system. The life of a CAES plant has two components; the turbo machinery and the underground cavern. Turbo-machinery typically has a life of 20 years before major replacements are needed. With necessary maintenance the life may be extended to 30 to 40 years. Salt caverns have a tendency to close up if they are not pressurised, but if the storage pressures are maintained in the caverns, they will have an indefinite life. Hard rock caverns also have an indefinite life.

State of the Technology

There have been two major deployments completed to date: the first in the 1970s in Huntorf Plant in Germany (290 MW for 10 hours), the other in McIntosh, as discussed above. Since the McIntosh Plant was built, there have been several advances in the technology of gas turbines that increase the efficiency, including: increased compression and inlet temperatures to the expander. In addition, there have been further studies in advanced CAES which include storing heat energy generated in the compression cycle for use in the generation cycle. Currently, the interest in energy storage to support wind and other renewable energy sources is leading to continual advancement of CAES technology.

The main supplier of CAES equipment is Dresser Rand, who supplied the machinery train for the McIntosh Plant in Alabama. In the 1990s, Westinghouse was also developing concepts for CAES equipment based on their gas turbine technology. Siemens has since acquired Westinghouse, and it is not known if they have maintained their interest in CAES. Currently there are several CAES projects planned in both Canada and the United States. The planned CAES developments in

Canada include projects in Nova Scotia and Saskatchewan. The planned United States projects include developments in Ohio (2,700 MW at an existing limestone mine) and North Dakota.

Applicability, Opportunities, and Limitations

CAES is limited to specific areas where there is suitable geology for underground storage, accessible fuel such as natural gas, and a suitable transmission line close by. Therefore, a central grid with long-distance distribution would favour CAES. In some cases, where all the necessary requirements come together, CAES could also be used to support a regional grid. In Canada, Landis Energy plans to construct a CAES system on the Alberta-Saskatchewan border to support such a grid.

CAES has a reasonable control capability during the generation phase and can be turned down 20% to 30% from maximum power. Several compressors, instead of a single large unit, can be used to accommodate load variation. The reliability of CAES plants is analogous to gas turbines. However, components unique to CAES plants, such as the recuperator, require increased maintenance.

CAES technology has several limitations. It is limited to areas with favorable geology and the necessary access to utilities. High construction costs of underground facilities favours the use of existing mines, salt formations suitable for solution-mined caverns, and depleted oil and gas wells. CAES plants discharge similar gases as combustion turbines and require pollution controls limiting NO_X, SO_X, and other pollutants. However, emissions per kWh are less than typical gas turbine plants.

5.5 MOLTEN SALT

Many fluids and solids have been investigated as possible mediums for thermal energy storage, including: concrete, sand, synthetic oils, silicone oils, and molten salts. Molten salts have the advantage of low vapour pressure, high temperature stability, high thermal conductivity, low chemical reactivity, low cost, and have been demonstrated at commercial scale[v]. They have been used for decades in high temperature heat transfer applications and were first used in the energy sector for nuclear reactor cooling in the 1950s. In the 1970s, molten salts were suggested for storing thermal energy produced from concentrated solar thermal and traditional thermal power plants. Currently, molten salt thermal energy storage has been primarily applied in concentrated solar power (CSP) plants located in the south-western United States and Spain.

Principles

The system consists of one or more tanks, pumps, heat exchangers, and working salt. Single tank systems are referred to as “thermoclines” where hot salt floats on cold salt. Two tank systems separate hot and cold salt and are more common[vi]. Cold salt, usually stored at 50°C above its melting temperature, is pumped from the tank through a heat exchanger where its temperature is increased by the heat source. The hot molten salt is then stored or pumped through a second heat exchanger where it heats water and generates steam for electricity production. A large variety of salts are used, each combination having different properties, including the melting point and upper temperature limit. Currently, the most commonly used salt is “solar salt” (a 60:40 mixture of sodium and potassium nitrates which melts at 220°C and has an upper temperature limit of 600°C and an effective heat capacity of 1.53 kJ/kg·K)[vii].

Although thermal energy storage has been suggested for thermal power plants, its primary application has been for concentrated solar thermal power plants. The molten salt dampens the variability of solar thermal sources with added ability to shift power to peak demand. These plants have two main configurations: parabolic trough and heliostat (or power tower). In a parabolic trough plant, oil (such as Therminol 66) is passed through a long pipe heated by sunlight focussed by parabolic mirrors. The oil then transfers the heat to steam for direct electricity generation or is stored for future use. In a heliostat, a field of flat mirrors focuses sunlight on a single point at the top of a tower to which molten salt is pumped and directly heated.

Power, Efficiency, and Economics

The amount of energy stored within a molten salt is proportional to the mass, heat capacity, and temperature difference of the salt in the system. Solar thermal plants have temperature differences of 100 °C to 300 °C. The first commercial-scale system is rated at 50 MW storing 1,000 MWh of thermal energy. Suggested upper limits for a molten salt system are 250 MW and 11,000 MWh of thermal energy storage[viii]. The size of the system is only limited by the number of tanks and amount of salt. The thermal storage efficiency of molten salt is typically greater than 90%[viii]. Heat losses from tanks are 1 °C to 2 °C per day[ix]. The stored energy recovered is utilized to produce steam and subsequently electricity at efficiencies in the range of 30% to 40%.

The largest portions of the capital cost are the salt and storage tanks, which make up 50% and 20% of the total, respectively. The capital cost of a complete system is estimated between 30 and 60 USD/kWh of thermal energy stored. Although operating experience with these systems is limited, the estimated life of a two-tank salt system is about 30 years[viii].

State of the Technology

The use of molten salts as heat transfer fluids is a mature technology that is used in many industries, including metallurgical and nuclear applications. Molten salt as a medium for thermal energy storage has been demonstrated over the past three decades in several demonstration-scale solar thermal plants. The only current, commercial-scale plant uses a two-tank molten salt configuration.

There are numerous engineering firms, start-ups, and governmental research organizations working on molten salt energy storage in conjunction with concentrated solar power. In the US, major development work has been conducted through the US Department of Energy's (DOE) SunLab; a collaboration between the National Renewable Energy Laboratory and Sandia National Laboratories[x]. The technology was demonstrated at Solar Two, a demonstration plant in California, as well as several others. The development was done through Hamilton-Sundstrand which is commercializing the technology through a new venture called SolarReserve. In Spain, molten salt storage is under development in a collaboration between SENER and CIEMAT (Spain's national centre for research into energy, environment, and technology). The first commercial-size plants with molten salt storage was the 50 MW Andasol 1 plant in the Andalusia region of Spain owned by Solar Millennium AG. The largest solar thermal plant incorporating salt storage will be the Solana project, a 280 MW facility in Arizona, owned by Abengoa, set for completion in 2011.

Applicability, Opportunities, and Limitations

Molten salt thermal energy storage can support a system with several regionalized grids. It delivers the ability to shave peaks for base load power sources (nuclear, coal) and may be a cheaper alternative to building new plants to address peak demand. Also, in the case of intermittent power sources, molten salt energy storage allows time-shifting and buffering of production variability of solar resources.

Major limitations with molten salt energy storage include: the need for abundant clear-sky solar irradiation and issues of pipe freezing (due to high melting temperature of the salt).

5.6 HYDROGEN ENERGY STORAGE

Hydrogen has been considered for use as an energy carrier for transportation and electricity storage since the 1970s. The promise of a hydrogen economy focuses on the use of hydrogen as a universal energy carrier and storage medium. Many government-led research initiatives globally are striving for the goal of making hydrogen a viable alternative to fossil fuels for transportation and a medium for electrical storage.

A hydrogen energy storage system could store electricity in the form of chemical potential in hydrogen gas produced from water via electrolysis or other high temperature chemical processes. Hydrogen is then stored and used later to generate electricity, as a transportation fuel, or chemical feedstock.

Principles

Hydrogen storage, in the context of electrical generation, is comprised of three major operations: 1) hydrogen generation, 2) hydrogen storage, and 3) electricity generation.

Two primary methods of converting energy into hydrogen are electrolytically and thermochemically... Electrolysis utilizes electricity to split water into hydrogen and oxygen gases. Thermochemical hydrogen production utilizes thermal energy and multistep chemical reactions to convert water to hydrogen. Some studied processes include nuclear power plants coupled to the copper-chlorine cycle, sulphur-iodine cycles using temperatures of up to 800°C, or concentrated solar thermal plants of 1200°C[xi,xii]. Several storage methods include gas compression, liquefaction, and metal hydrides.

Three methods are available for generating electricity from stored hydrogen: 1) internal combustion engine, 2) gas turbine, and 3) fuel cells. Modified diesel generators are capable of burning hydrogen as are gas turbines. Fuel cells are based on the same concept as electrolysers except they work in reverse and produce electricity from hydrogen.

Power, Efficiency, and Economics

It has been estimated that hydrogen energy storage is viable for power ratings up to 10 MW[xiii]. Although hydrogen is a very energy intensive molecule per mass, the necessity of multiple steps to produce and store hydrogen deteriorates system efficiency: electrolysers between 56% and 78% efficient, from electricity; thermochemical production estimated at 50% to 60% from thermal energy; liquefaction conventionally 45%; and compressed gas storage around 90%.

For electricity production, internal combustion engines have an efficiency between 25% and 45% while fuel cells are higher between 50% and 70%. Overall the resulting efficiency of hydrogen production, storage and electrical generating system is disappointingly low, ranging from 18% to 25%.

Electrolysers are the major cost of the system. The projected unit capital cost for an electrolyser over its lifetime is between 9 ¢/kWh and 24 ¢/kWh based on the electrical energy used to produce the hydrogen[xiv]. Electrolysers have an estimated lifetime of 15 to 20 years. The cost to produce electricity from the stored hydrogen also varies depending on the technology used; a fuel cell system can cost between 1,000 and 3,500 USD/kW depending on the system used; gas turbines 200 to 600 USD/kW. Fuel cells have an expected lifetime of 10 years as do internal combustion generators.

The only hydrogen energy storage system deployed in the world to date is the Ramea Island project, in Newfoundland at a capital cost of 2,000 USD/kWh of available storage capacity, including hydrogen production, storage, and electrical generation.

State of the Technology

Although hydrogen energy storage has not been commercialized, there are a handful of demonstration projects currently underway. Electrolyzers have been commercialized, while thermochemical production is at the pilot stage. Compression and liquefaction are mature technologies, while metal hydride storage is commercialized for small-scale applications.

The Japanese Atomic Energy Agency is piloting a thermochemical hydrogen generation process for integration with their next generation nuclear reactors. Thermochemical production with nuclear reactors is also being investigated by General Atomics (US), while solar thermal systems are pioneered by DLR (Germany). The competing route of electrolysis is being commercialized by Hydrogenics (Canada) and Norsk Hydro Electrolysers (Norway). Industry has, however, put a greater emphasis on hydrogen utilizing technologies, evident by the number of firms developing fuel cells – Hydrogenics (Canada), Ballard Power Systems (Canada), FuelCell Energy (US), UTC (US), Proton Energy Systems (US), and Siemens. In addition to production and consumption technologies, there are a number of organizations commercializing hydrogen storage technologies, including: US DOE and NREL, Italian National Agency for New Technologies, Energy and the Environment, and GE Global Research.

Applicability, Opportunities, and Limitations

On a national scale, hydrogen is currently best suited to be used not as a storage medium for electricity but as a chemical feedstock. Currently, hydrogen shows applicability for electricity storage only for remote communities to accommodate variability of renewable generation while delivering dispatchable power during peak demand on these micro-grids. Industrial processes which require hydrogen as a feedstock, could combine inexpensive, off-peak generation and storage in order to offset electrical demand during expensive peak periods.

Hydrogen energy storage has the benefits of fast response time, long-term storage ability, and limited ecological footprint. Although a handful of the required technologies for electricity-to-hydrogen-to-electricity systems are mature, there are still significant limitations; poor electricity-to-electricity efficiency, high capital cost, and limited experience as a storage medium. Electrolysers and fuel cells have not been deployed with large power ratings (MW range). The most challenging aspect is that hydrogen has the lowest viscosity and density of all gases resulting in energy intensive compression and liquefaction routes. Another big barrier is that hydrogen is primarily produced from fossil fuel sources which are significantly less expensive routes than electrolytical or thermochemical production.

5.7 BATTERY ENERGY STORAGE

Principles

Batteries store energy in the form of chemical reactions. Batteries are composed of “cells”, each containing two half-cells: positive and negative. Each half-cell contains an electrode and electrolyte and is connected to its other half through a membrane or a bridge. At the negative electrode chemical compounds undergo a reaction where they are split into positively charged ions and electrons. Electrons flow through the negative electrode and an external circuit ending up at the positive electrode. The ions produced at the negative electrode move through the electrolyte and the membrane to recombine with the electrons at the positive electrode in another set of chemical reactions. Charging a battery reverses the reactions and flow of ions. Each type of battery uses different electrode materials and electrolytes and works on a different set of chemical reactions and internal structures. See Table 5.1 below for an outline of the operating characteristics of each battery type.

Table 5-1: Principles of Given Battery Types

Battery Type	Negative Electrode	Positive Electrode	Electrolyte	Chemistry	Notes
Lead-Acid[xv]	Metallic lead	PbO_2	Concentrated sulfuric acid	Pb converted to $PbSO_4$ during discharge	Two main configurations: flooded and valve-regulated
Nickel Cadmium[xvi]	Metallic cadmium	NiOOH	$KOH\cdot(H_2O)_{(aq)}$	Cd oxidized during discharge	More tolerant of abuse, higher energy density, longer life, more expensive than Pb-acid
Nickel-metal Hydride	Metal alloy capable of absorbing hydrogen	NiOOH	$KOH\cdot(H_2O)_{(aq)}$	Metal allow releases H during discharge	Higher energy density, longer life than NiCd
Lithium-ion[xv]	Graphitic carbon (MCMB)	CoO_2	Liquid, gel, polymer, or ceramic	At discharge e^- and Li ions liberated from carbon. Ions combine CoO_2	High energy-to-weight ratio, no "memory effect"
Sodium-Sulfur	Pure sodium	Metal (Cr or Mb) casing	Beta aluminum	At discharge Na turns to Na ions, e^-. S ions pass through electrolyte, react with Na produce NaS_5	Discharge reaction is exothermic, operating temperature near 300°C
Zinc Bromine[xvii]	Zinc bromide in solution	Zinc bromide in solution	Aqueous solution containing "electrodes"	During charging Zn combines with e^-, plates the negative electrodes. In positive electrolyte, Br is formed in solution. At discharge Zn frees e^-, dissolves as positive ion. Br combines with e^-, becomes negative ions	Electrons move through metal electrodes that do not participate in chemical reactions. Easily scalable and have potential for large-scale applications
Vanadium Redox[xviii]	V^{3+}/ V^{2+} in solution	V^{5+}/ V^{4+} in solution	Vanadium and sulfuric acid mixtures	During charging at negative electrode, V^{3+} ions converted to V^{2+}. At positive electrode, same process with V^{5+} and V^{4+}	See above Power rating and energy storage capacity are independent of each other

See **Detailed Battery Operating Characteristics** for a more detailed outline of each battery type.

Power, Efficiency, Economics

Table 5-2 summarizes the characteristics of the batteries described in this section. The maximum power refers to the amount of power output for those systems using current technology, but does not necessarily refer to the most common application. Efficiency refers to the DC-to-DC efficiency of electricity in versus electricity out. Capital cost and operating costs are on a basis of electricity stored.

Table 5-2: Power ratings, efficiency, and costs associated with various types of batteries.

Battery Type	Max. Power [MW]	Capacity at Max Power [MWh]	Energy Density [Wh/kg]	Specific Power Density [W/kg]	Efficiency (DC-DC)	Operating Life	Capital Cost [USD/kWh]
Lead-Acid [xv,xix ,xx]	10	20	30 – 40	70 – 100	75% – 85% (decreases at high temp.)	5 – 7 years	200 – 1,000*
Nickel Cadmium [xv,xvi,xx]	>10	20	20 – 60	330 – 460	60% – 70% (lower with high charging rate and temp.)	800 – 1,000 cycles (80% DoD) 50,000 cycles (10% DoD)	900 – 3,000
Nickel Metal-Hydride [xv, xvi]	>10	20	60 – 90	200 – 600	65% – 85%	15 years	
Lithium-Ion [xx,xxi]	<10	<3	~150	1,000	80% – 90% (lower due to self-discharge)	3,000 cycles (100% DoD) 20,000 cycles (40% D0D)	1,000
Sodium-Sulphur (NGK) [xx,xxii ,xxiii]	6	2 – 48	~225	1,000	~90% (77% including required PCS)	2,500 cycles (100% DoD) 4,500 cycles (90% DoD)	500 – 1,000
Zinc Bromine [xv,xx,xxiv]	<10	0.5 → >2.5	75 – 85	90 – 110	70% – 80%	2,000 cycles (~6000 hrs)	100 – 1,000
Vanadium-Redox [xv,xviii,xx]	>6	1.6 → >4	10 – 20		75%	14,000 cycles	100 – 1,000

*Note: Most lead-acid batteries are on the lower price range ($200/kWh) and these are the models that would find most application in an electrical grid context.

State of the Technology

Lead Acid

Grid-scale storage capacities are not practical due to electrochemical properties, limited energy density, and a widely agreed upon maximum voltage of 2,000 V[xix, xxv]. Berliner Kraft and Licht, developed a lead-acid storage facility from 1981 to 1986 which provided 8.5 MW for one hour and required 7,080 flooded cells, arranged in twelve strings[xix]. Southern California Edison initiated the Chino Battery Storage Project in 1986 as a means of studying the use of battery storage for load-leveling. The storage plant consisted of 8,256 flooded lead-acid batteries delivering 2,000 V. The plant had a rating of 10 MW for four hours and operated from 1991 to 1997[xix].

Nickel Electrode

ElectroEnergy Inc., based in Danbury, Connecticut, makes high-rate nickel-metal hydride (NiMH) batteries. The company is entering the utility market with batteries for load shifting applications[xxvi]. ECD Ovonics Inc. also specializes in NiMH batteries and is involved in the application of NiMH batteries as storage for solar power systems[xxvii]. Saft, a major battery manufacturer, produces a line of low maintenance nickel cadmium (NiCd) batteries that are meant to replace valve-regulated lead-acid batteries and is planning to release a battery meant specifically for power quality applications[xxviii].

The Golden Valley Electric Authority (GVEA) has a Battery Energy Storage System (BESS) in Fairbanks, Alaska. The battery used in the system is a Saft SBH 920 pocket-plate NiCd. Since start-up in 2004, the battery has prevented 46 outages, discharged at full power for 24 minutes (up from 15), and discharged at 46 MW for 5 minutes (breaking the world record for most powerful battery)[xxix].

Lithium-Ion

A123 Systems owns a technology based on lithium iron phosphate, claimed to have increased conductivity and energy density relative to other Li-ion technologies[xxx]. Saft has also developed a rival technology which it has applied to electric vehicle applications. Valence, a battery developer in Texas, markets and develops Li-ion technology which utilizes an electrode made from lithium iron magnesium phosphate. Valence is targeting the utility markets for load-leveling, renewable source backup, and uninterruptible power supply applications[xxxi]. AltairNano of Nevada, is developing lithium titanate oxide electrodes which are claimed to increase battery lifetime, charging rate, and energy density[xxxii].

Sodium-Sulfur

NGK, a Japanese electric power equipment manufacturer, partnered with TEPCO, and began to commercialize the sodium-sulfur battery under the NAS® brand name in the 1990s[xxii]. Some larger installations include two 6 MW – 48 MWh load leveling systems at the Tsunashima and Ohito substations, a 2 MW – 14.4 MWh load leveling and UPS system at a media centre, and a 3 MW – 7.2 MWh load-leveling and UPS system installed for Fujitsu at its Akiruno Technology Centre[xxxiii]. In the US, NGK installed a peak shaving and power quality unit that can provide 500 kW for up to 30 seconds as a demonstration facility for EPRI and American Electric Power (AEP)[xxxiii]. In 2003, the system was deemed successful, which led AEP to the 2006 installation of a 1.2 MW system at the

Charleston substation of its subsidiary, Appalachian Power. The system is meant to provide 7.2 MWh for peak shaving and costs 2,000 USD/kW[xxxiv],[xxxv].

Flow Batteries

Zinc Bromine

The ZBB Energy Corporation, the only company currently developing zinc bromine technology, was formed by a research group at Murdoch University in Perth, Australia. After purchasing the technology developed by Exxon, ZBB developed demonstration projects based on a 50 kWh module that contains three cell stacks of 60 cells each. Using this module, the company constructed a 250 kW, 500 kWh system it plans to use for supply and storage in grids that need transmission and distribution upgrades[xxiv]. Another demonstration facility is located in Lum, Michigan and acts as a load levelling option for Detroit Edison. The system was installed in 2002, and provides 400 kWh storage capacity and is capable of discharging for 2 to 10 hours. It is meant to provide backup to a transformer that is usually running at or above capacity[xvii]. ZBB also teamed up with photovoltaic cell maker PowerLight Corporation and the New York State Energy Research and Development Agency to install a 50 kW, 100 kWh system for use in peak-shaving and uninterrupted power supply[xxiv].

Vanadium Redox

The vanadium-redox battery (VRB) was developed in 1984 by the New South Wales University (UNSW) of Sydney, Australia. The work done was based on previous work on redox batteries by NASA and the Electro-Technical Laboratory in Japan. Currently, Pinnacle VRB holds all of the rights to the technology and licences it out to VRB Power Systems Inc. of Vancouver (Since bought by JD Holdings Inc. of China) and Sumitomo Electric Industries (SEI) of Japan.

VRB Power installed a 250 kW demonstration facility with at the University of Stellenbosch in South Africa. The system has six 42 kW stacks of 100 cells each that vary in voltage from 650 to 850 V[xviii]. The discharge time is 2 hours. After the 2001 installation, the project was deemed a success and was followed by a 250 kW, 2 MWh installation in Utah and a 200 kW, 800 kWh installation in Australia, to help with load-levelling in wind-powered supply[xviii].

Applicability, Opportunities, and Limitations (All Batteries)

Batteries may be applicable to a scenario of regional grids within Canada. Their relatively low energy capacity means they could not be used as large energy reserves. If a large percentage of renewable power is deployed, however, batteries could time-shift or level the intermittency of these power sources. In the case of base-load generating facilities, battery storage could be used for short term peak-shaving with long-term storage batteries, like flow batteries. In a scenario with a main central grid, batteries would be less applicable. A large national grid would allow the transfer of electricity from overproducing regions to overloaded ones with reduced need for storage. Where batteries may find application in this scenario is in providing support to long-distance transmission. The placement of batteries at problematic substations or transmission nodes may be necessary to improve power quality. In the hybrid scenario where regional grids are linked by some long distance transmission, batteries would be applicable in the same way as in the previous scenarios. In cases where electricity storage is required and the geography does not allow for pumped hydro or CAES, a flow battery could be implemented.

Batteries have several benefits in their use as energy storage devices. Batteries have performance characteristics that lie between power-boosting capacitors and SMES, and long-duration pumped hydro and CAES. In terms of controllability, batteries have a response time on the order of seconds, possibly less and have the capability to match any load within their power rating. Many of the battery technologies discussed are fully commercial and are already in use in many grid-scale systems. Battery technologies are all relatively independent of their location and geography. The temperature of operation for each type of battery varies. Li-ion and lead-acid batteries have a wide operating temperature range of approximately -40°C to 70°C. Sodium sulfur batteries operate at a high temperature, 290°C, which is maintained by integrated heaters. Flow batteries are also sensitive to temperature as the flowing electrolyte must not freeze. For example, Zn-Br batteries must operate in the 20°C to 50°C range.

A limitation of battery technology is that the maximum energy capacity is limited in comparison to other energy storage technologies, such as pumped hydro or CAES. Although many cells can be combined to create varying sizes of batteries, losses in transmitting the electricity through enormous circuits connecting the cells puts a limit on practical size. Other capacity limitations exist for individual battery technologies. For example, NaS batteries work with a solid electrolyte that is not stable above a certain size. The power rating of flow batteries is largely dependant on how quickly the electrolyte can be circulated through them, and this is a pumping issue more than an issue with the technology. Some batteries also have limitations in terms of memory effect. The memory effect occurs when nickel battery cells are cycled at a low depth of discharge, causing a larger decrease in voltage and capacity at the end of each cycle. At a utility scale this would be less of a problem because of the use of a “float charge”.

Another current limitation is cost as battery technology is relatively expensive, in comparison to pumped hydro on a per kWh basis, or diesel in terms of back-up power. With wider implementation and economies of scale, the cost of batteries may decrease. In addition to capital cost, batteries also have various maintenance and operational costs. Battery systems are composed of many individual cells which require periodic replacement. Some batteries, such as lead-acid and NiCd require float charging (application of a small voltage to prevent self-discharge), equalization charging (charging individual cells that are not fully charged), and reconditioning (full charge and discharge). All of these activities require the use of energy that cannot be recovered. Electrolyte replacement or the addition of water is also necessary in some unsealed battery designs. An added cost specifically related to flow batteries is the maintenance and replacement of pumps.

During operation, batteries have a very low environmental impact. However, the disposal of batteries at the end of their lifetime requires special care. Many battery types contain toxic or hazardous compounds including cadmium, bromine, lead, concentrated acids or bases, sodium, and vanadium. Recycling of battery materials is an option to mitigate waste. Lead-acid batteries already have effective recycling and safe disposal programs, with over 90% of battery materials recycled.

5.8 SUPERCONDUCTING MAGNETIC ENERGY STORAGE

Superconducting magnetic energy storage (SMES) is based on the fact that materials considered superconductors can carry current with no losses due to resistance. The electric current carried by these materials can be used to induce a magnetic field that can be used to store energy[xxxvi]. Initially, SMES was intended for load-leveling, but its quick discharge capabilities make it a perfect candidate for maintaining system stability and power quality[xxxvii].

Principles

All SMES systems are comprised of a coil of superconducting material, a power conditioning system, a refrigerator, and a control system. Energy is stored through a magnetic field which is generated by flowing current through the superconducting coil. The alloy used for the coil is niobium-titanium (Nb-Ti) cooled to -269°C to achieve its superconducting properties. The coil is one of the most costly parts of the system so it is designed to store the maximum amount of energy per length or weight. The maximum current allowed in the coil is determined by the conductor size, materials, operating temperature, and the magnetic field created. The magnetic force can be quite substantial, requiring a containment structure around the coil[xxxvi]. A cryogenic refrigerator using helium as the working fluid is used to achieve the low temperatures required for the superconducting coil[xxxvi]. About 200 W to 1000 W are needed to remove a single watt of heat. This makes the insulation of the system of crucial design importance.

The power conditioning system (PCS) is needed to control the state of current in the coil. A PCS produces a positive voltage across the coil to store energy, and a negative voltage for energy discharge. The voltage change causes current buildup or decrease. At discharge, the current decreases, so the rated power of the SMES system must be that which the PCS can provide at the lowest current, usually half of the maximum. At the end of discharge, about one fourth of the total current remains in the coil[xxxvi]. A control system is also necessary to regulate the amount of power and energy stored into or discharged out of the SMES to the connecting grid. That same system also monitors the state of the refrigerator and other components, and sends information out to the operator[xxxvi].

Power, Efficiency, and Economics

Energy storage units of this sort have been conceived for almost any size or power capacity, ranging from 0.3 kWh to 1,000 MWh and 1 MW to 1,000 MW, respectively[xxxvi]. The typical use of these plants is for quick power quality boosts which require capacities from 0.8 to 28 kWh and the ability to discharge in about one second[xxxvi]. Larger units with power ratings of up to 100 MW still tend to discharge their energy in a short burst of about 10 seconds. Even with the power requirements for refrigeration and the build up of resistive loses, SMES systems can be up to 95% efficient, and load-leveling SMES plants designed in the past have had efficiencies as high as 92%.

On a power basis, the capital cost of SMES is approximately 600 USD/kW to 1,500 USD/kW. On an energy storage basis, these systems can cost in excess of 50,000 USD/kWh[xxxviii]. SMES coils have no moving parts and no electrodes or electrolyte to degrade, leading to a cycle life that is virtually limitless. However, some components of ancillary systems such as refrigeration would need to be replaced or repaired periodically.

State of the Technology

SMES technology has been commercialized for small and large-scale applications. American Superconductor is the major player in the industry with its D-SMES unit. The 3 MW D-SMES system has 0.9 kWh of storage and is housed in a 18.6 m long trailer that weighs 29,500 kg[xxxix]. The company has delivered nine of the D-SMES systems as a part of three different power systems in the US[xxxix]. The company has also deployed systems all around the world with power ratings as high as 8 MW and capacities of 0.8 kWh[xxxix]. ACCEL of Germany has provided smaller systems for uninterruptible power supplies with an average power of 200 kW over 8 seconds, translating to 0.44 kWh[xl].

While there are many applications of small SMES systems around, there is only one major demonstration facility for a large grid stability SMES system. This system is located in North Wisconsin, for the Wisconsin Public Service. It uses 6 D-SMES units and intial tests are proving successful[xxxvi]. The total estimated amount of support for a rapid discharge system has been US$ 50 million worldwide by the industry. The United States Defense Department has funded an Engineering Test Model with US$ 72 million for a load-leveling application and has been supported by industry with an additional US$ 75 million[xxxvi].

Applicability, Opportunities, and Limitations

The main application of SMES systems will be for power quality and grid stability, but not for large reserves of power. SMES may have an application in regional grids to control the power surges or sags in the grid due to the intermittency of power from wind or solar power generation. In a large centralized grid SMES could be used as a power quality insurer at grid nodes and power substations. In a hybrid system with regional grids connected by long distance transmission lines, power quality issues would be designed out of the system making SMES less applicable.

The main advantages of SMES technology is that it can provide relatively high power discharge in very short periods. The quick response time of the system could give the grid or the system operator the required power surge instantly, which implies a high degree of controllability. SMES technology also has a long life cycle and has no limitations in terms of where it can be located geographically. SMES also has several limitations as a support to grid electricity. The system has a relatively low energy capacity; a 160 km long coil would be required to store 1 GWh. Another limitation is the cryogenic refrigeration which would require frequent inspections and highly trained operators. There is also a concern over the large magnetic field generated by the coil and the long term effect it may have on organic tissue. SMES installations would likely have to be placed at considerable distances from residential areas or sensitive wildlife.

5.9 ELECTROCHEMICAL CAPACITORS

The electrochemical process at work in this type of capacitor, namely the double-layer effect, was discovered by Henrich Helmholtz in the 1800s[xli]. In 1957, the first electrochemical device was patented by General Electric and was first put into use in computer memory backup in 1979. Electrochemical capacitors have an energy density that is higher than capacitors and lower than batteries[xlii]. The need for energy storage technologies in the past few decades has allowed the industry to grow to annual sales of US$100 million[xlii].

Principles

In a conventional capacitor, charge is stored by electrons being removed from one surface and deposited on another. Traditional capacitors have two metal plates separated by a dielectric material such as air. In an electrolytic capacitor an electrolyte replaces one of the metal surfaces and there is no dielectric material to separate the charge[xli].

Electrochemical capacitors have plates that are composed of multiple layers of a material or a porous material, usually activated carbon. The electrolyte is injected in between plates which are separated by a porous film. During charging, ions from the electrolyte are attracted to the electrode with the opposite charge. The ions fill the pores of the electrodes without reacting[xliii]. The charge and energy stored by a capacitor are related directly to the surface area of the plate and inversely to the separation of the plates. Electrochemical capacitors allow for a very large surface area, due to porous electrodes, and very small separation between layers.

Electrochemical capacitors are divided into four types. Type I and Type II capacitors use a symmetric design with activated carbon electrodes and either an aqueous solution (acidic or basic) or organic electrolyte, respectively. Type III and Type IV capacitors use an asymmetric design, with one electrode identical to those in Type I and the other a faradaic pseudocapacitor, which relies on reactions at the electrolyte interface to store charge. The pseudocapacitor electrode is consumable, like the ones used in batteries, but it has a much higher capacity than the carbon electrode. Type IV capacitors, currently under development, use an organic electrolyte[xlii].

Power, Efficiency, and Economics

The amount of energy available in capacitors is highly dependent on the discharge rate. At faster rates of discharge there is a large decrease in efficiency. The power ratings and storage capacity for several commercially available units are in Table 5-3. Electrochemical capacitors have power densities in the range of 1,000 W/kg to 10,000 W/kg which is superior to some batteries[xliv]. The efficiency of an electrochemical capacitor system is highly dependant on the internal resistance between cells in series and the time between charging and discharging. These capacitors have a daily self-discharge of 1% to 2% of the energy stored[xlv]. However, for short-term storage the efficiency of this type of system is 75% to 95%, with possible efficiencies of over 99%[xlvii].

Table 3-3: Electrochemical Capacitor System Power and Energy[xlvi]

Product	Max. Power Rating (kW)	Energy Capacity (kWh)	Discharge Time at Max. Power (s)
Siemens Sitras SES	1,000	2.5	9
ESMA 30EC402	100	16.7	10
Maxwell Boostcap	302	0.15	1.8

On a power application basis, the cost of capacitors can range from 50 USD/kW to 500 USD/kW. With energy applications, the cost is around 100 USD/kWh to 10,000 USD/kWh[xlvii,xlviii]. The cycle life of electrochemical capacitors can exceed 500,000 cycles. However, each cycle is very short, at about 1 second each way, so the calendar life of capacitors is not very long.

State of the Technology

Electrochemical capacitors are a fully commercialized technology with major deployment by the same companies that developed the technology. Nippon Electric Corporation (NEC) has manufactured Type I capacitors since 1980. Their products are typically 14 V units with an energy capability of 8 kJ. In 1978, Panasonic started producing an organic electrolyte Type II capacitor called “Goldcap”. Their products typically have a power rating of 2.5 V and a capacity for 6 kJ. Maxwell Technologies is the leading US manufacturer of electrochemical capacitors, with products rated at 2.5 V and 8 kJ[xliii,xlix]. NEC, Panasonic, and Maxwell Technologies are developing capacitors for vehicular applications with high power and high energy capacities[xliii,xlix]. Two Russian companies involved in the development of this technology include Elit Company (Type I, 14 to 400 V, 50 kJ) and The ESMA Company (Type III, 14 V to 180 V, 20 kJ to 30 MJ). The ESMA Company has supplied capacitors to power electric buses and have products that can be integrated into a system with voltages up to 600 V[xliii,xlix].

Siemens developed the Sitras Static Energy Storage (SES) system to harness the energy in light rail lost during braking while entering a station and use it in acceleration when leaving a station. A system of 32 racks of 42 Maxwell 2400 F capacitor cells in series was designed (1 MW, 2.3 kWh, up to 750 V). The demonstration facilities in Portland, Oregon and Dresden, Germany have shown that this reduced the power requirement for the local substation by 30%[l,li]. Other demonstration sites exist, but they are mostly geared to grid stability applications and do not involve significant energy storage. Asymmetric designs, Type III and IV, are the focus of current research and development. In the near future, the energy density of Type III capacitors is expected to double to 70 kJ/kg[xliii].

Applicability, Opportunities, and Limitations

Electrochemical capacitors have low energy capacities and are mainly intended for power quality servicing. The capacity of electrochemical capacitors is too low to be viable for energy storage, although new capacitors are being developed for long-term storage and discharge. In the case of a regionalized grid, capacitors would be able to smooth out surges and sags in voltage during power generation from intermittent sources such as wind. In a large central grid scenario, they would be able to ensure power quality for long-distance distribution. Capacitors can be used at substations or transmission nodes to increase power during voltage sags and to compensate for power quality lost during transmission. In a hybrid grid scenario with regional grids and long-distance distribution, capacitors would act as a bridge to facilitate many sources of power working in tandem. Capacitors also have an application in backup power systems where during a power outage they could provide bridging power while generators start up.

This type of capacitor has several attractive features as a storage device. The technology is relatively mature and is available commercially from several suppliers. Discharge times for electrochemical capacitors are longer than other capacitor systems and some models in development have storage capacities in the same range as batteries. These systems are not restricted by geography and have a large operable temperature range (-55 °C to 85 °C) with little or no environmental impact. Also, the reliability of capacitors can be assumed to closely resemble that of batteries. The main limitations for electrochemical capacitors are their cost and energy density. The cost of capacitors is currently too high to compete with batteries that can provide the same service. The energy density of capacitors is low and the technology is usually not used for long-term energy storage[xlvii]. A minor concern is that the capacitors using organic electrolytes, namely Type II, use acetonitrile which is flammable and highly toxic requiring special disposal and safety considerations.

5.10 ELECTRIC VEHICLE-TO-GRID STORAGE

Vehicle-to-grid (V2G) is the concept where a battery-powered vehicle (a passenger car) acts as an energy storage unit for the grid. When the vehicle does not require the power from its batteries to drive the electric propulsion motor, it would "absorb" electricity during off-peak times (at night and early in the morning), and discharge some of that electricity back to the grid at times of peak demand (afternoon and early evening). Note that because V2G is the application of existing battery technology rather than as a technology itself, it is treated here somewhat differently than the above-mentioned storage technologies. The intent here is to look at V2G in a conceptual sense and consider what effect its availability might have on a national grid.

While plug-in electric vehicles (EVs) for road use and plug-in hybrid electric vehicles (PHEVs) are essentially non-existent at the present time, it is expected that a number of automotive manufacturers will begin selling such vehicles in the near future (Chevrolet Volt, expected 2010, plug-in Toyota Prius 2011). V2G is often thought of as a Smart Grid technology in that it can aid the demand management concepts of "valley filling" and "peak shaving", both of which are intended to allow power generating plants to operate at a more consistent capacity factor throughout the day and ultimately reduce the demand for peak-generating capacity. V2G as a storage technology is a subset of battery storage (discussed earlier), but with the difference that each installation is quite small (10-15 kWh) and only starts to play a meaningful role as a solution to utility-scale storage once there is a large installed base of electric vehicles. The basic battery technology that is currently available for use by EVs and PHEVs are lead acid (standard automotive battery), NiMH (Toyota Prius), and Lithium Ion (Chevrolet Volt).

Principles

The principle behind a vehicle's usefulness as an energy storage point relies on the fact that the vast majority of personal-use vehicles stand idle for some 20+ hours per day. A typical day for an automobile used by a commuter might look something like this: 7 am, drive to work for one hour; sit in the office parking lot from 8 am to 5 pm, drive home at 5 pm for one hour, drive around town for two hours for errands, and remain parked from 7 pm to 7 am the following morning. Therein lies the value of V2G – it is the auxiliary use of an otherwise idle capital asset. To understand what the overall capacity of a fleet of V2G capable vehicles could be, assume that future electric vehicles will have a useful 10 kWh battery pack (the 1st generation Chevrolet Volt has been specified at 8.8 kWh of useful capacity[lii]) and that the capacity of each year's new battery packs grows such that the fleet average battery pack performance increases by 2% year-on-year. Further assume that the market penetration of plug-in vehicles begins with 1% of North American vehicle sales in 2010 (ca. 15 million vehicles) and continues to grow by 2% per year until the annual new vehicle market penetration reaches 33% of new vehicles sales by 2026 (at 16 years, the useful life of the vehicle is assumed to be depleted, and hence new vehicles sales would then include those that displace non-EVs and those that replenish the existing fleet). Hence, by 2026, one might expect that 43 million electric vehicles could be in use. Assuming the full-cycle capacity at a fleet average of 13.7 kWh per vehicle per day by 2026 – GM claims 65 km of range on batteries only from 8.8 kWh of useable capacity for the Volt, the raw capacity available for absorption from the grid would equal 595,000 MWh. Of this "valley filling" charging, assume that the average charge that any user would be willing to give up to the grid and still provide enough remaining capacity to safely reach the terminal destination at the end of the day is 20% (including those who give up nothing because they are not on the grid or cannot afford to give up the charge), then the electricity that could be returned to the grid after losses in the battery are included is approximately 100,000 MWh. If one further assumes that the peak period lasts for about 5 hours, say 2 pm to 7 pm, and the instantaneously available power from the V2G storage option is approximately 20,000 MW distributed across the North American grid. About 7% of this capacity might be local to Canada, estimated as such on the basis that the Canadian light vehicle fleet size is 7% of the US light vehicle fleet size – this assumes that relative penetration of PHEVs into the overall fleet will be similar for both countries[liii]. Hence, 1,500 MW or 7,500 MWh could be delivered back to the grid by vehicles which have been charged in low demand conditions. Using the above assumptions, with 80% battery reclaim efficiency and 50% subscription to a V2G service among EV owners, Figure 5-2 and Figure 5-3 below outline what the market and system rating would look like in the Canadian context. Notice that the power rating of such a system is quite low (maximum at ~2,000 MW). But it should also be noted that such a system would result in a V2G market of CA$ 100 million, even at the modest market penetration value of 30% for EVs, and a Peak/0ff-Peak price differential of only 0.05 CAD/kWh.

Figure 4-2: Canadian V2G Annual Market Size at Different EV Penetration Percentages

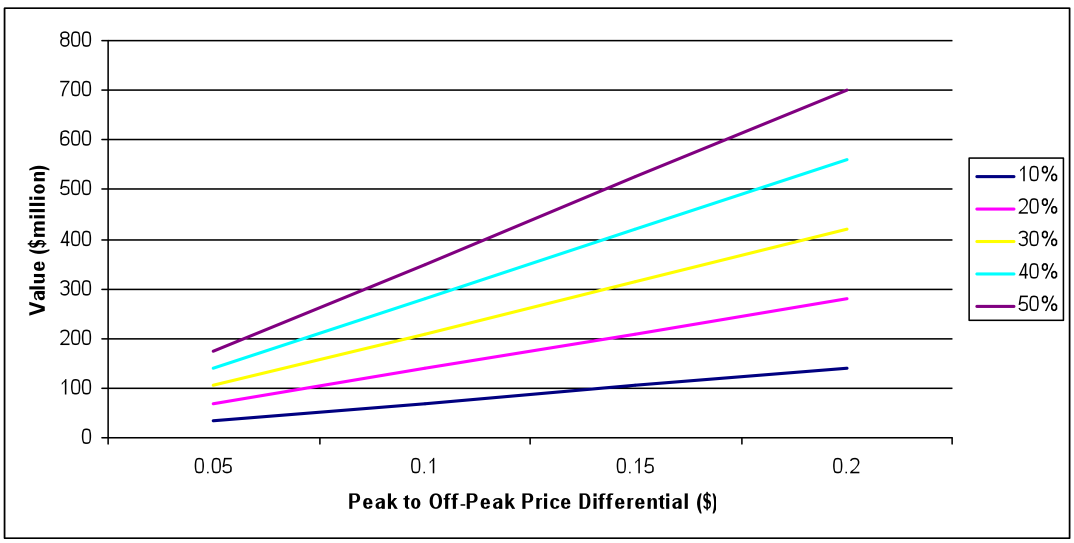
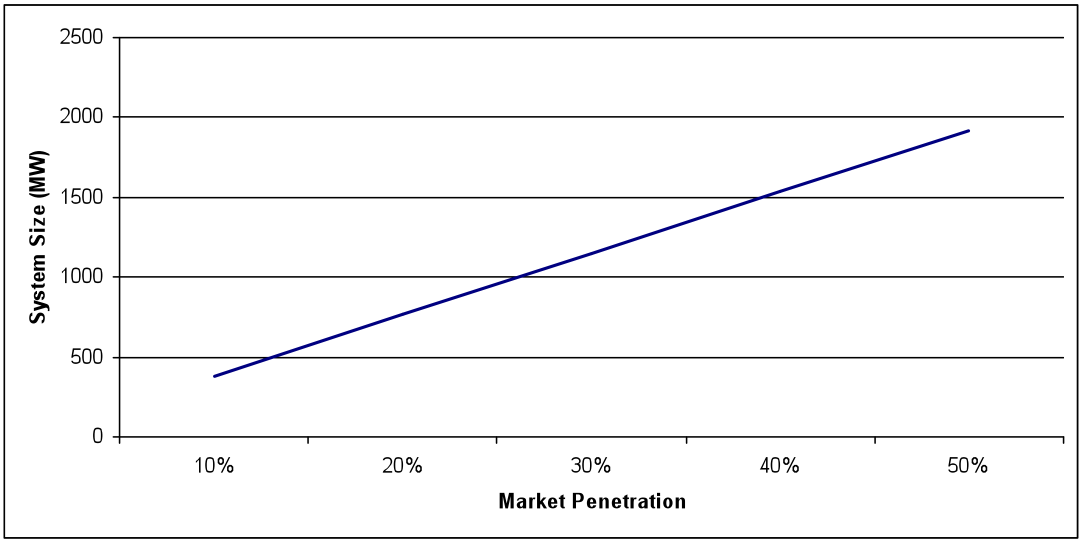


Figure 5-3: V2G System Size in Canada



Applicability, Opportunities, Limitations

However, there are a number of caveats to the potential of this concept. First, the effect of additional cycling of the battery is that the lifespan (in years) of the battery will be shortened relative to the distance driven when compared with a battery pack that is never used to send power back to the grid – this can be overcome via the rate paid to the vehicle owner for making his vehicle available to the grid. A Li-ion battery can be expected to last 3,000 cycles at an 80% depth of discharge, but only about 1,400 cycles at 100% depth of discharge[liv,lv]. Thus, the usage pattern of the battery could give it an in-vehicle life of approximately 4 to 10 years. Second, the battery packs for EVs can be expected to be expensive relative to stationary batteries – reason being that the charge capacity per unit weight (or volume) on a vehicle application must be quite high as the vehicle must use some of the available energy just for the purpose of accelerating the battery pack each time the vehicle accelerates in speed. A heavy battery pack has a trickle-down effect through the rest of the vehicle – heavy batteries require a heavier chassis which, in turn, requires a stronger suspension, bigger brakes, bigger tires, and so on. Unlike a stationary battery, which can be placed into an insulated building, a vehicle battery pack must be able to perform well in extreme temperatures, from -30°C to 40°C, hence the technology requirements in a vehicle battery pack are quite high in order to satisfy this requirement; the electrical loads in vehicles also increase with extreme weather. Third, charging and discharging infrastructure must also exist – in the case of single-family homes with garages, this is not a difficult challenge as electrical outlets are readily available. However, only a small percentage of vehicles ever get parked in garages as many cars are street-parked. This will require sufficient charging infrastructure in residential areas – curb-based electrical outlets are one concept – and sufficient daytime charging/discharging infrastructure at parking lots and city streets. The required charging/discharging infrastructure must also be sufficiently intelligent and communicative with the grid to recognize vehicles and provide the necessary billing and settlement for the vehicles.

Nonetheless, the potential of the concept is appealing. First, it can provide a peak demand solution as illustrated in the calculations above – V2G has also been suggested for its potential as an ancillary service provider, including spinning reserve and regulation.[lvi] Second, the storage source moves with the load (residential to industrial/urban/commercial), thereby reducing the need for transmission and distribution infrastructure. Third, vehicles could be used to provide some temporary power in emergencies – given that many of these vehicles will be hybrid vehicles with an internal combustion engine coupled to an electricity generator to extend the range, the capacity for emergency power is not limited to the battery capacity. Fourth, some percentage of the automotive fleet would not require hydrocarbon fuels and be able to do so without requiring additional electrical generating capacity.

Ultimately, V2G does not support a transcontinental national grid scenario – it is essentially distributed storage that is roughly distributed with demand locations.

5.11 SUMMARY/SCORECARD

After reviewing the above energy storage technologies, it was logical to determine the suitability of each technology for specific applicability to the national Canadian grid. The scorecard in Figure 5.4 7 below was devised to assess how each technology could perform in each of the pertinent categories, which include:

Maturity,

Power Rating,

Reclaim Efficiency,

Capacity,

Response Time & Controllability,

Geography,

Capital Costs, and

Lifetime.

Operating costs were not evaluated due to the fact that few concrete values exist for many of the technologies and many of the values that do exist are speculative, as some technologies have not been implemented on a large scale.

Each technology is rated on a scale of 1 to 5 (5 being the most favourable), in each of the above categories. A weighting was given to each category as well, as category importance varies in the context of a national grid application. The ratings were multiplied by the weight of the category and the sum of all categories determined the score. The conditions used to determine the ratings and the justification for the weights given to each category can be found in Rating Descriptions and Definitions. Such ratings are based on an installation's performance in terms of power rating, efficiency, energy capacity, etc. These ratings do not necessarily reflect what is currently practiced but what is reasonably applicable.

The scorecard below brings to light some important points. Primarily, the fact that traditional (ponding) and pumped hydro storage emerged as the most favourable technologies is fully expected and is in line with prevailing views. These are not only the most mature options but also provide the highest efficiencies, power ratings, and storage capacities; the lowest unit capital costs; and longest lifetimes, all of which are favourable to a grid application. Also, in a modern power grid, energy storage will need to enhance the full exploitation of renewable sources and the demand loads will need to be levelled to reduce the inefficiencies and costs introduced by the traditional excesses. This is best achieved with storage installations capable of holding large amounts of energy and discharging for long periods. The importance of large scale installations is further illustrated by the fact that the 3rd and 4th ranked technologies, compressed air (CAES) and molten salt with solar themal power, are both suited for large scale applications.

Although the rankings given below may indicate a path to follow with regard to which technologies should be invested in and deployed, it is not meant to be a detriment to technologies that rank lower. The technologies following the four top-rated ones, namely batteries, capacitors, and SMES, are all very well-suited to providing power quality and voltage stabilization. These will be important tools in a national grid for improving the power quality performance of larger storage technologies. The technologies that rank last, vehicle-to-grid and hydrogen energy storage are brought down by their lack of maturity and high capital cost. Hydrogen is further burdened with low electric-to-electric efficiency, which is a crucial attribute for use in electric utility applications. Assuming that electricity-based electrolytic hydrogen becomes a competing route for producing industrial hydrogen feedstocks (e.g. ammonia, etc.), then its production and storage at chemical plants could play an important role in levelling the supply-demand variations in the electrical grid.

The importance of power and energy capacities of the technology candidates for supporting a major electrical grid is presented in Figure 5.4 8, below. Note that the top right of the graph features technologies that are capable of discharging at high power levels for long time periods (hydro ponding, pumped hydro, CAES, molten salt). As is shown in the graph, these technologies are well suited for Energy Management. The bottom of the graph (EC capacitors, SMES) features technologies that cannot discharge for lengthy periods, but do so at substantial power levels. This makes them excellent candidates for Power Quality management where large capacities are not required and where a smaller, lower cost installation capable of discharging at high power is preferred. The figure also indicates the suitability of batteries in meeting short term energy supply, mainly as Bridging Power to cover the time between power outage and reserve initiation.

Figure 5.5 8 also illustrates the limitation of hydrogen for electric-to-electric energy storage quite well. Although a hydrogen installation would be able to discharge for long periods, on the order of hours, at those capacities, it would clearly make more sense to install a CAES or molten salt plant (both capable of higher power ratings and greater efficiency). Furthermore, if geography does not allow such plants, flow or NaS batteries would suit the requirement more efficiently than hydrogen storage.

Figure 5-4: Energy Storage Technology Scorecard

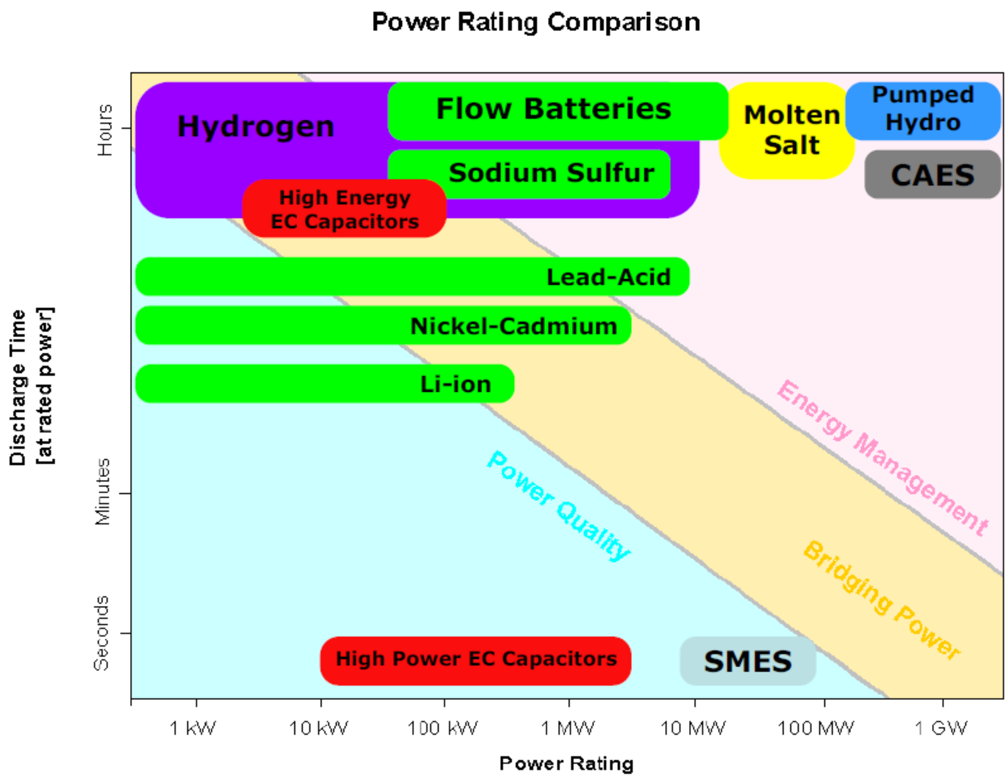
Storage Technology	Maturity	Power	Reclaim Efficiency	Capacity	Response Time & Controllability	Geography	Capital Costs	Lifetime	Score	RANK
Weighting	2	4	2	4	1	1	2	2	–	–
Traditional Hydro	5	5	5	5	4	3	5	5	87	1
Pumped Hydro	5	5	4	5	3	3	5	5	84	2
Compressed Air Energy Storage	3	4	4	4	3	3	5	5	72	3
Molten Salt	3	4	2	4	3	3	4	4	64	4
Batteries Li-Ion Pb-Acid Ni NaS Flow	5	2	4	2*	5	4	2	2	51	5
Hydrogen	2	2	1	3	4	5	2	3	45	9
Capacitors	4	3	5	1	4	5	2	2	51	5
Superconducting Magnetic Energy Storage	3	3	5	1	4	4	1	3	48	7
Vehicle to Grid	1	4	4	3	1	4	1	1	47	8

* Does not include Flow Batteries

Notes

1. Battery Maturity rating excludes NaS and Flow batteries
2. All Power and Capacity ratings are based on the theoretical capability per unit installation
3. Vehicle to Grid Power rating is defined with the system understood to be the Grid
4. Response Time & Controllability for Vehicle-to-Grid is based on the development limitations to date
5. Geography & Environment ratings are based on the effects of operation only (i.e. not including manufacturing)

Figure 5-5: Power-Energy Comparison for Energy Storage Technologies



Source: Energy Storage Association

The services that energy storage would need to provide, mainly peak-shaving, compensating for demand load variation, and facilitating the penetration of wind and solar power, are currently being addressed with the use of natural gas in “peaking” plants. These plants are designed to provide the additional power required during peak consumption periods, so that the base load plants are not overwhelmed. The reasons that natural gas is currently the method of choice for peak load demand are simple – simplicity, profitability, and existing infrastructure. With currently attractive natural gas prices, a peaking plant is a profitable investment for operators, since they sell their product, peak power, at premium prices. Natural gas, however, is not a long-term solution and this is the incentive behind the relatively recent interest in energy storage. Many players are interested in installing energy storage installations to purchase cheap power at off-peak periods and sell the stored energy during peak periods, for a premium. Taken in this context, investment in an energy storage installation seems very profitable and will attract eager investors. This business model, however, is flawed as there will inevitably come a time when the electricity market is saturated with energy storage installations, at which point a levelling of prices between peak and off-peak consumption will occur. Without the ability to purchase cheap off-peak power, energy storage plants become financially risky.

Although energy storage is a requirement for a future Canadian grid, who would be willing to invest millions of dollars into a potential money sink? The Federal and Provincial Governments could, but taxpayers will want accountability and governments cannot be seen as spending frivolously. Of the two top-rated technologies, traditional hydro and pumped storage, the latter can only gather revenue from storage. Traditional hydro plants, on the other hand, derive most of their profit from the generation of electricity, and energy storage is simply a bonus. Molten salt, in association with concentrated solar power, can also generate as well as store electricity, but in the Canadian context, solar thermal power is less viable. On an economic basis, no energy storage technology can compete with hydroelectric installations.

Conversely, hydroelectric generation facilities come at a relatively high initial expense. In the long-term, the low cost of power generation and the added storage capability makes this a golden long-term investment and has resulted in the development of many readily accessible sites. Therefore, a larger plant, possibly 2,000 MW, will have a high unit capital cost due to more remote locations, possibly at 4,000 USD/kW, and an initial price tag of US$ 8 billion. With the added complication of long lead and construction periods, around 7 years, it would be difficult to sell the public on a large hydroelectric plant, the benefits of which may not be seen for years.

There are two possible solutions to the quandary posed above. The first is a strong government commitment to invest in hydroelectric power by both convincing the public of its future benefits and withstanding the initial criticism. The James Bay project in Quebec cost CA$ 20 billion and was pushed through with the determination of the premier at the time, Robert Bourassa. The project now generates 16,000 MW and provides the revenue necessary for the province to fund its social programs in perpetuity.

The second solution to the dilemma of who pays for expensive hydroelectric projects is for government to provide the necessary incentives and regulation that would make pursuing large hydroelectric projects feasible for industry. This is the preferred method of those that believe government is best at regulating, not operating, business. The Ontario Government took steps in this direction in 2009 with the introduction of generous feed-in tariffs for incentivizing renewable energy. These are meant to bring down the payback period of investing in expensive renewable energy projects. Another possible incentive, particular to remote hydroelectric projects, is to mandate the transmission providers to construct the required transmission from new hydroelectric projects, provided that the station owner/operator contributes to the cost of construction.

Hydroelectric power is the clear path to supplying the energy storage required for a modern and integrated Canadian electrical grid. With the ability to store large blocks of energy and generate power from a source that is practically free, other storage technologies face great difficulty in competing. The right government action to promote hydro power will bestow upon Canada an enormous competitive advantage for the foreseeable future.

5.12 RATING DESCRIPTIONS AND DEFINITIONS

The technologies investigated in this report all have inherent benefits in the context of a Canadian national grid scheme. The purpose of this section is to evaluate, both quantitatively and qualitatively, the applicability of each technology and determine, based on a weighted scoring, the technology most favourable for widespread adoption. Regardless of the score given in this evaluation, each technology will retain the benefits it inherently has, as outlined in the sections above. This means that using any of the above technologies would be beneficial for a national grid in some way. The ranking determined in this evaluation will only serve to bring a focus to specific technologies that would most aid in the implementation of a Canadian national grid. The rating for a technology in any given category is based on what an installation using the technology is capable of and not necessarily what such installations are currently doing in practice. Furthermore, each rating was given to the technology in isolation from what it could be used for. For example, the capital cost of a pumped storage plant was not considered in terms of being partnered with a wind farm. Instead a general survey of costs for various plants was considered.

Maturity

In order to determine a rating for the maturity of a given technology, research on commercial, demonstration, and laboratory scale work was considered. The rating is largely based on a qualitative view of the level of development experienced by the technology. Also considered were the level of commercialization and the availability of this technology in the marketplace. From these considerations, it is easy to infer that hydroelectric storage would be the most mature technology, on all levels. Vehicle-to-Grid energy storage on the other hand ranks the lowest, as it is still in the theoretical stage and has minimal demonstration and practically no commercial aspects. It is interesting to note that older technologies do not necessarily rank higher in maturity as it is possible that the development of newcomers has outpaced them. This is true for compressed air energy storage, for example. Although conceived and developed before Li-ion batteries, CAES is nowhere near as commercially available today.

Weighting

The weighting of the maturity rating was set at a 2. This category was deemed very important for the implementation of a specific technology to a national grid. However, maturity of some of the technologies may improve by the time a national grid is constructed; therefore the rating was not given the highest possible weighting.

MATURITY	
Rating	**Description**
5	Technology is widely available commercially Multiple vendors supply the product(s) Major development is concluded
4	Technology is commercial Relatively new to the market and/or not widely supplied Some development is still underway
3	Technology is well into or approaching the end of demonstration/pilot phase and some commercial plants (1-2) Demonstration(s) show positive results Commercialization underway or will be in the near future
2	Demonstration plant(s) have been operated Early results available Economic viability still in doubt
1	Conceptualization is still underway Demonstration facilities are planned Research still occurring on basic technology implementation

Power

The rating of power for each technology was determined by simply creating categories of installation ratings. Two things should be noted with respect to the given ratings. The rating given to each technology is based on available (or soon to be) installations. This means that for batteries, the rating is not based on what a single battery or cell is capable of but instead of what an installation of such batteries would be capable of. Second, although several of the technologies investigated have a high theoretical maximum power, the rating here was given based on what has already been achieved in practice or what is feasible for an installation in the foreseeable future. There are also examples of each technology that may have a capability outside the given rating for the technology, but specific instances of a very specialized high-power battery, for example, are ignored.

Weighting

The power rating was given a weighting of 4. In any application, power is always one of the primary considerations. Any energy storage technology will have to be able to discharge at high power levels in order to meet the demand of the grid. While smaller power levels can be beneficial to individual consumers, in the context of grid applications, they are of little use. This is why power was given the highest weighting.

POWER	
Rating	**Power Rating Range**
5	> 1,000 MW
4	200 MW → 1,000 MW
3	50 MW → 200 MW
2	1 MW → 50 MW
1	< 1 MW

Efficiency

The rating for efficiency is simply based on what the reclaim efficiency is of an average installation using each technology. By reclaim efficiency, what is meant is the percentage of electricity released by the installation for each kWh of electricity used to "charge" the installation. This definition of efficiency is the reason technologies like molten salt and hydrogen rate so low. Included in their efficiency is also the efficiency of the generator used to generate electricity from the storage medium. These generators are usually turbines or fuel cells, which have inherently low efficiencies. Note in the table below that efficiencies below 40% are not differentiated and are all given the same rating. The reason for this is that it allows for more differentiation in the upper ranges, where most of the efficiencies lie. Also, differentiating between technologies that are more inefficient than an internal combustion engine is unwarranted.

Weighting

The efficiency rating was given a weighting of 2. The efficiency of a technology is a significant factor in its applicability to a national grid. As a modern "smart" grid will look to minimize the loss of generated power, efficiency energy storage will be crucial. The efficiency rating was not given the highest weighting as it was not deemed as important as the power and capacity ratings, both given the highest weighting.

EFFICIENCY	
Rating	**Efficiency Range**
5	85 – 100 %
4	70 – 85 %
3	55 – 70 %
2	40 – 55 %
1	< 40 %

Capacity

Like the power rating, capacity is rated based simply on the ability of an installation to store enough charge to provide energy for a certain amount of time. As with power, the rating given is based on the average available (or soon to be available) facility and not on the theoretically possible capacity. Also excluded from the rating are specialized products of each technology that exceed the average capacity of the technology. For example, long-duration electrochemical capacitors are not considered in the rating for electrochemical capacitors because, although they exist, they are not the average and customary application of the technology and are not feasible for use over other long-term discharge technologies.

Weighting

As with the power rating, capacity was weighted at a 4. This is the highest weighting since capacity is always one of the prime factors in determining the suitability of a technology for specific application. While smaller capacities may be useful for individual consumers, larger capacities will be required for gird applications, and the ability to story energy for long periods of time will be crucial in the implementation of renewable power and long-distance transmission.

CAPACITY	
Rating	**Discharge Times (Capacity in Wh)**
5	> 20 hours (> 20 GWh)
4	5-20 hours (1-20 GWh)
3	1-5 hours (10-1,000 MWh)
2	< 1 hour (1-10 MWh)
1	< 1 minute (< 1 MWh)

Response Time & Controllability

The main focus of the ratings given in this category is the level of operability that the technology gives to the grid system or operator. In the context of a national power grid, the energy storage technologies in this study will most likely be used as a tool by each grid operator to help control loads, power quality, shave peaks, and provide reserve power. The ability of the technology to suit these needs is largely based on the response time and its ability to match the required load conditions. For all of the technologies the response time is very quick; the only differentiation possible is between minutes and seconds. In terms of the load-matching capabilities of each technology, not much information is available and therefore the evaluation for ranking them is somewhat qualitative and largely based on the inference of professional opinion. Finally, the capacity factor was taken into account. This was the reason, for example, why traditional hydroelectric energy storage was given a higher rating in this field than pumped storage.

Weighting

This rating was given a weighting of 1. Response time and controllability can be taken into account when designing a grid system. The capability of each technology in this field is considered before it is applied and any deficiencies can be designed around.

RESPONSE TIME & CONTROLLABILITY	
Rating	**Description**
5	Response time on the order of seconds Load matching capability in very narrow power ranges
4	Reponses time on the order of ten seconds Load matching capability in narrow power range
3	Response time on the order of seconds to minutes Load matching capability in narrow power range
2	Response time on the order of minutes Load matching capability in wide power range
1	Response time on the order of minutes Load matching ability is very limited

Geography

When evaluating the applicability of each technology in terms of geography, the Canadian range of climates and landscapes was considered. For climate, the major factor evaluated was the effect of temperature, especially extreme cold, on the operation of the technologies. To a lesser extent, the effect of humidity or precipitation was contemplated. Other factors taken into account were topography and surroundings, such as wildlife. All of the technologies rated quite well in this regard; hydroelectric and compressed air energy storage were brought down by their need for elevation and specific rock formations, respectively; superconducting magnetic energy storage was brought down by the effect hotter temperatures may have on cryogenic cooling and the possible effects of large magnetic fields on wildlife.

Weighting

The geography rating was given a weighting of 1. Any deficiencies a technology has in applicability in a certain geographic location can be designed around.

GEOGRAPHY	
Rating	**Description**
5	Completely operable in all climates No dependence on surroundings (i.e. topography)
4	Operable in almost all climates Little dependence on surroundings
3	Operable in almost all climates Dependence on surroundings
2	Some dependence on climate Heavy dependence on surroundings
1	Heavily dependent on climate Completely dependent on surroundings

Capital Cost

The capital cost rating for each technology was determined qualitatively by the capital cost of installing a facility on the basis of the energy supplied by each facility over a lifetime. The reason that a per unit energy cost was selected was to show the true cost of each facility's utilization over its useful life. If the costs were rated on a power basis, technologies like SMES would rate quite high. This, however, would not be a sincere representation of the technology as using this technology for an application that would need longer discharge times than an SMES installation is used to would result in exceedingly high costs. It should be noted that because cost information is hard to come by, the ratings given here are not all based on the actual industry experience. For more mature technologies, the costs are based on the available information from previous installations. For newer technologies, the costing is based on the capital costs projected for installations in the near future. While projected costs also exist for new installations of mature technologies, such as pumped storage, these projections are not much lower than the cost of recent installations.

Weighting

The capital cost rating was given a weighting of 2. In any selection process, the cost is always a key factor; therefore the cost rating given to each technology is important. The reason that the highest weighting was not given is that capital cost projections are always changing and it would be incorrect to give a large weight to a rating that may increase or decrease in the near future. Furthermore, the cost for some technologies may decrease sooner than others.

CAPITAL COST	
Rating	**Cost**
5	< $100/kWh
4	$100-500/kWh
3	$500-1,000/kWh
2	$1,000-5,000/kWh
1	> $5,000/kWh

Life

The life rating for each technology was determined based on the average useful life of an energy storage installation using each technology. The lifetime was determined based on the calendar life and not the number of cycles that the installation could go through. Some technologies, such as electrochemical capacitors, can go through thousands of short cycles, so if a cycle rating was used, these technologies would be rated highly, even though they cannot compare to large hydroelectric installations, for example. Calendar life, however, has its own downside, in that it does not take into account large periods of time when the installation is sitting idle.

Weighting

The life rating was given a weighting of 2. The average lifetime of an installation is a very important aspect to consider as a large national grid would require permanent storage installations. The less frequently these installations need to be replaced the better. However, this rating was not given the highest weighting as replacing a facility is also reflected in the capital cost, and it would be incorrect to account highly for this cost twice.

LIFE	
Rating	**Lifetime**
5	> 25 years
4	15-25 years
3	10-15 years
2	5-10 years
1	< 5 years

5.13 DETAILED BATTERY OPERATING CHARACTERISTICS

Lead-Acid

Lead-acid batteries are the most recognizable batteries worldwide, with sales constituting 40% to 45% of all batteries sold in 1999. In a lead-acid battery, the positive electrode is a plate of lead dioxide and the negative electrode is made of metallic lead. Antimony is usually incorporated into the positive electrode to slow corrosion. The electrolyte is a solution of concentrated sulfuric acid. During discharge, the metallic lead is converted to lead sulfate, protons (acidity), and electrons which travel through the circuit. The lead oxide combines with electrons from the circuit and protons forming lead sulfate. There are two main configurations of lead-acid batteries: flooded lead-acid and valve-regulated lead-acid.

Flooded Lead-Acid Batteries

Also known as the vented lead-acid battery (VLA), this type dominates the market and is the one primarily used in automobiles. These batteries have a flat-plate configuration using lead-antimony or lead-calcium grids submerged in excess electrolyte. These batteries allow for large current discharge and relatively low cost, but are not well-suited for deep-discharge cycling. Deep-cycle batteries that use thicker plates and high antimony content, however, have been designed for use in electrically-powered vehicles and stationary power for utilities and telecommunications.

Valve Regulated Lead-Acid Batteries (VRLA)

In the VRLA configuration, the electrolyte is held within an absorbent separator, such as glass mat, or a gel. The electrolyte cannot exit the battery as in the VLA configuration. VRLA batteries have an estimated life of 10 to 20 years, but in real-life use the lifetime is closer to 3 to 7 years. VRLAs have the disadvantages of sensitivity to temperature and over-charge/discharge conditions.

Nickel Electrode

Nickel can be combined with many materials in many different battery technologies. The most common types are the nickel-cadmium (NiCd) and nickel-metal hydride (NiMH). The NiCd battery was invented by Waldmar Jungner in 1899. In the 1930s the sintered-plate electrode was invented and in the 1940s the sealed NiCd cell was developed followed by wide adoption in portable electronics in the 1970s. The NiMH cell was developed in the 1970s and soon replaced the NiCd battery in portable electronics.

In all types of nickel-electrode batteries, the positive electrode is made of nickel oxyhydroxide (NiOOH). During discharge it combines with electrons and is converted to nickel hydroxide ($Ni(OH)_2$). The electrolyte in these batteries is concentrated aqueous potassium hydroxide $KOH \cdot (H_2O)$. NiCd and NiMH batteries differ in the material used in their negative electrodes.

Nickel-Cadmium

In NiCd batteries, the negative electrode is made of cadmium. During discharge the metal is oxidized to cadmium hydroxide, liberating electrons that flow through the electrode. Nickel-cadmium batteries fall into three different types: industrial pocket-plate, vented sintered-plate, and sealed designs. Compared to lead-acid batteries, they are more tolerant of abuse, have a higher energy density, longer cycle life, are easier to maintain, and are more expensive.

Nickel-Metal Hydride

In the NiMH battery, the negative electrode is a metal alloy capable of absorbing and releasing hydrogen as the battery is charged and discharged. These alloys are usually either rare-earth alloys based on lanthanum nickel or alloys of titanium and zirconium. During discharge, hydrogen is released, combining with hydroxide ions to form water and electrons. The sealing of these batteries is required to prevent the escape of hydrogen. The storage of hydrogen in a metal hydride allows for a higher energy density than NiCd batteries, as well as better cycle life. This comes at a higher cost and a sensitivity to over-charge and high-rate discharge. It is also difficult to manufacture the metal-hydride matrices used in these batteries so few have been constructed for utility applications.

Lithium-Ion

Lithium-ion (Li-ion) batteries were introduced by Sony in 1991 and are now ubiquitous as the power source for many portable electronics. The main advantage over previous rechargeable batteries is their high energy-to-weight ratio and no "memory effect" for recharging after a partial discharge.

In a lithium ion battery, the negative electrode is commonly graphitic carbon such as Mesocarbon Microbead (MCMB). Lithium ions are "intercalated" within the graphite layers of the negative electrode. During discharge electrons are liberated from the carbon structure and positive lithium ions are de-intercalated from the structure. The ions pass through an electrolyte and combine with the positive electrode which is an oxidized metal matrix such as cobalt oxide ($LiCoO_2$). The electrons combine with the positive ions and the lithium becomes intercalated within the metal matrix. There is currently a large amount of research being conducted in both academia and industry to develop new materials for the positive electrode. Li-ion batteries use one of four types of electrolytes: liquid, gel, polymer, or ceramic. Liquid electrolytes are solutions of lithium salt in organic solvents; gel electrolytes are a film matrix containing lithium salt in a carbonate solvent; polymer electrolytes are non-liquid and contain a salt dissolved in a polymer; and ceramic electrolytes are solid-state ion conducting materials.

Sodium-Sulfur

Sodium-sulfur (NaS) batteries have been around since the 1960s and have found applications in satellites and stationary power. Recently the Tokyo Electric Power Company (TEPCO) selected NaS technology for their distributed energy storage system.

The negative electrode in a NaS battery is pure sodium. A metal separator of beta alumina separates a main sodium chamber from the actual sodium electrode. As the battery is discharged sodium is replenished at the electrode from the chamber. The electrolyte in the cell is beta aluminum and the negative electrode is sulfur. During discharge sodium breaks down into positive sodium ions and electrons. The positive sodium ions pass through the electrolyte and react with the sulfur to produce sodium pentasulfide. The metal separator prevents too much sodium interacting with the sulfur. The reaction that occurs during discharge generates heat and, as a result, these batteries operate at temperatures in excess of 300 °C. Resistance heaters are used to maintain the temperature around 290 °C during standby or when charging, when the reactions require heat.

Flow Batteries

Flow batteries work on the same principle as regular batteries, except the electrodes are liquids that are stored in external tanks. The electrode material is dissolved or suspended in the electrolyte. The positive electrode liquid is called the catholyte and the negative electrode liquid is called the anolyte. The anolyte and catholyte are stored in separate tanks and pumped through the cell where the chemical reactions take place. In the cell the catholyte and anolyte are separated by a membrane that allows ions to pass through. Electrons move through solid metal electrodes that do not participate in the chemical reactions. Flow batteries are easily scalable and have the potential for large-scale applications. The two types of flow batteries considered here are the zinc bromine flow battery and the vanadium-redox flow battery.

Zinc Bromine

In a zinc bromine battery both the catholyte and anolyte consist of zinc bromide in solution. During charging, zinc in solution combines with electrons and is converted into solid zinc that plates the negative electrodes. In the positive electrolyte, or catholyte, pure bromine is formed and remains in the solution. A separator between the two liquids allows the passage of ions between the two systems. During discharge the opposite occurs; solid zinc liberates electrons and moves into solution as a positive ion and bromine combines with electrons to become a negative ion in solution.

Vanadium-Redox (VRB)

VRB technology is based on the reduction/oxidation reactions between vanadium ions. During charging at the negative electrode, V^{3+} ions are converted to V^{2+} ions. At the positive electrode, the same process takes place with V^{5+} and V^{4+} ions. The electrolytes in the system are made of vanadium and sulfuric acid mixtures, one mixture as the positive electrolyte, or catholyte, and the other as the negative, or anolyte. The different electrolytes are separated in the cell by a proton exchange membrane that allows the flow of protons between the two halves of the cell. The power capability and the energy storage capacity of a VRB are independent of each other. The stack of cells and the power conditioning system determine the power in kW, while the electrolyte concentration and electrolyte tank dimensions determine energy storage capacity.

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6. HIGH VOLTAGE TRANSMISSION TECHNOLOGIES

6.1 INTRODUCTION

This section relates to “Review of Advancements in High Voltage Transmission Line Technology, Including an Assessment of the Use of HVDCHVDC” identified in the work plan for “Gigawatts for Canada – The Case for a National Power Grid”. It is assumed that the reader has a basic knowledge of HVDC transmission.

The scope of work includes:

Describe the state of the art of high voltage transmission technology and advances that might be anticipated.

Identify where high voltage direct current (HVDC) is being used and expected future applications.

Describe the advantages and disadvantages of HVDC in comparison to HVAC grid systems.

Identify where HVDC might have application in an expanded Canadian electrical grid system

6.2 HIGH VOLTAGE DIRECT CURRENT (HVDC) TRANSMISSION

Conventional Line Commutated Converter (LCC) HVDC is a well established technology. HVDC transmission with overhead line DC voltages up to +/- 500 kV and a transmitted power level of 3000 MW per single bipolar line are currently in operation. HVDC transmission with cables at DC voltages of up to 500 kV with transmitted power up to 700 MW per cable is also currently available. The transmitted power is limited by the cable design and in cases of cable transmission where higher power transfer levels are required, cables can be paralleled to provide the desired power transfer capability.

Recent advances in Ultra High Voltage DC (UHVDC) technology have resulted in HVDC systems with operating voltages of +/- 800 kV and power transmission levels in the range of 6000 MW per single bipolar line being planned and under construction.

VSC technology for HVDC power transmission applications has advanced quickly, starting from the Hellsjőn project with a rating of 3 MW in 1997 to the Transbay Cable Project with a rating of 400 MW which is planned to be in service in 2010. At the present time, VSC HVDC technology can attain ratings of up to1100 MW and +/- 320 kV with an overhead line and projections indicate that a full bipole at +/- 640 kV DC and 2200 MW is achievable.

Appendix 1 provides a list of HVDC systems as prepared for the DC and Flexible AC Transmission Subcommittee of the IEEE Transmission and Distribution Committee by the Working Group on HVDC and FACTS Bibliography and Records, May 2008.

Conventional Line Commutated (LCC) HVDC

Conventional Line Commutated Converter (LCC) HVDC employ thyristor technology and are also referred to as current source converters. In line commutated converters, the current flow is unidirectional and power reversal is accomplished by reversing the polarity of the DC voltage. Commutation of current from one valve to another requires an AC voltage.

Conventional LCC HVDC has been used in long distance overhead line and cable systems, and back-to-back applications. Back-to-back HVDC links do not include an overhead line or cable and are used to provide an asynchronous connection between to AC systems. HVDC transmission systems can be either monopolar or bipolar with electrode or metallic return.

Traditional applications of LCC HVDC include:

- Bulk power transfer over long distances using overhead transmission lines
- Transmission requiring long under sea or under ground cables
- Interconnection of asynchronous systems

Configurations

Monopolar

A monopolar HVDC link has only one high voltage conductor, referred to as a "pole", and the current return path is either through electrodes and ground, or through a dedicated metallic return conductor. Figure 6-1 and Figure 6-2 below show the basic configuration of a monopolar HVDC link with electrode return and with metallic return respectively.

Figure 6-1: Monopolar HVDC with Electrode Return

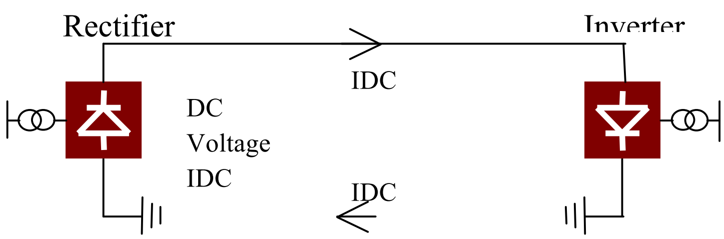
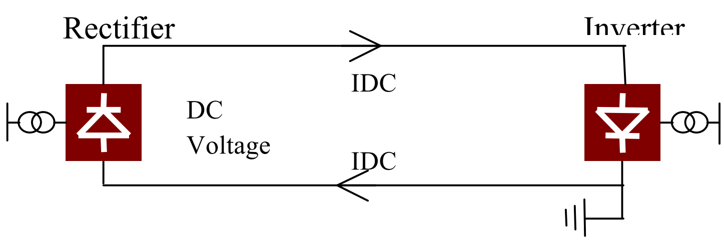


Figure 6-2: Monopolar HVDC with Dedicated Metallic Return



Ground electrodes can be located either on land, shore or in the sea. The effectiveness of land electrodes is highly dependant on the electrical properties of the local and regional geology whereas sea and shore electrodes benefit from the high conductivity of seawater and therefore local and regional geological conditions are not as relevant for site selection.

Use of ground return has some potential environmental impacts which must be mitigated. These include potential interactions with human, wildlife and marine life; corrosion of buried or submerged metallic structures; impact on AC power systems; interference with railway signals; and interference with communication systems.

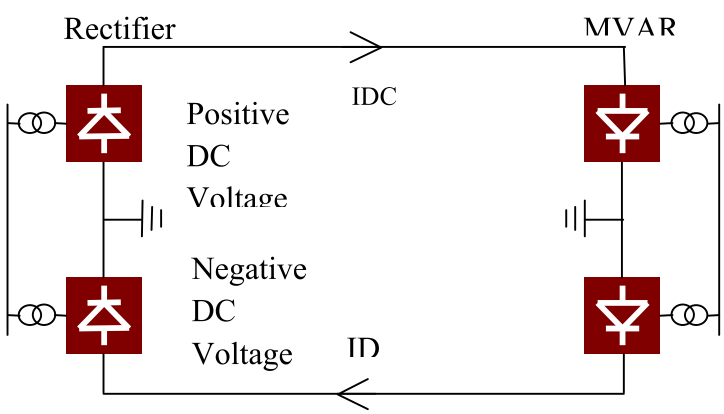
The addition of the metallic return provides a path for the DC current which avoids the use of ground return and the associated environmental concerns. The metallic return conductor must be rated to carry the full DC current however it can be rated for a much lower DC voltage that the high voltage conductor.

In most cases, the HVDC system is designed to be bi-directional, allowing HVDC power transfer in either direction. This is accomplished by changing the mode of operation of both stations (i.e. rectifier to inverter, and inverter to rectifier) in controlled manner.

Bipolar

A bipolar HVDC link has two poles of opposite polarity and the typical operation mode is with equal current in the two poles thereby avoiding current flow in the electrodes and ground as shown in Figure 6-3.

Figure 6-3: Typical Bipolar HVDC System



In the event one pole is out of service, operation of the second pole can continue using the electrodes and ground as the current return path similar to a monopolar HVDC with ground return. In cases where the loss of one pole is the result of the loss of converter capability, the metallic conductor of the out of service pole can be used as a metallic return path for the healthy pole, similar to a monopolar HVDC with metallic return. In order to utilize the metallic conductor of the out of service pole as a return path the system must include a Metallic Return Transfer Breaker (MRTB) which provides a means of automatically performing the required connections and commutating the DC current from the electrode to the metallic return conductor and vice versa when required.

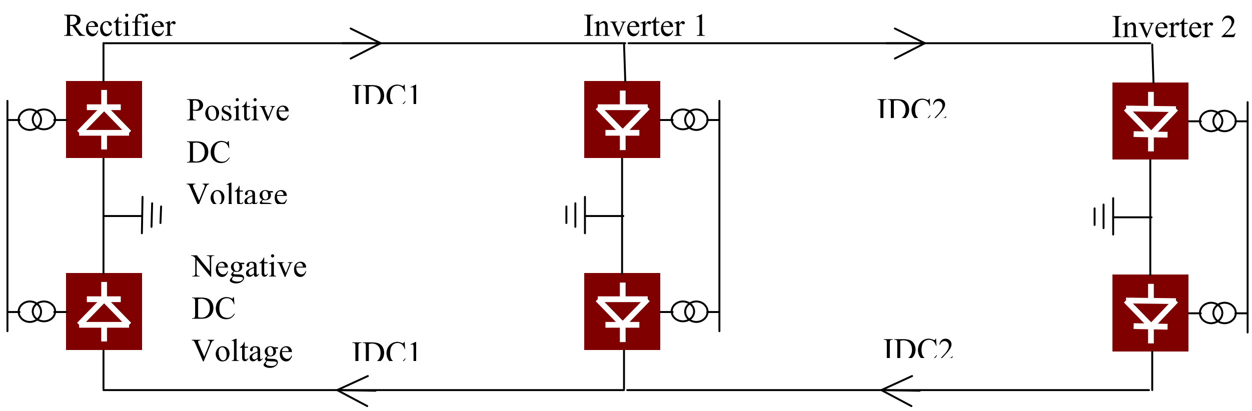
In situations where either suitable locations for ground electrodes are not available or where the use of ground return is not possible, a bipolar HVDC system can include a dedicated metallic return conductor. As in the case of the monopolar HVDC with metallic return, the metallic return conductor must be rated for the full DC current but a much lower DC voltage than the high voltage conductors.

Multi-Terminal HVDC

Most HVDC systems in service to date are two terminal systems, consisting of only one rectifier and one inverter terminal. Multi-terminal HVDC systems, consisting of three or more terminals, have been realized in a number of HVDC systems currently in operation. All multi-terminal HVDC systems in operation or currently being planned are realized by connecting terminals in parallel. The terminals can be geographically separated from one another or the multi-terminal HVDC system can be realized by placing converters in parallel to each other within the same station. This is sometimes done to increase the overall power transfer capability of the HVDC system without increasing the HVDC operating voltage.

Figure 6-4 below shows the basic configuration of a bipolar multi-terminal HVDC system consisting of one rectifier and two inverters.

Figure 6-4: Multi-Terminal HVDC with Three Terminals



Two existing HVDC systems have been designed as multi-terminal from the start:

Sacoi (Sardinia to mainland Italy with a parallel tap in Corsica)

Hydro Quebec – New England.

Two systems can operate in a multi-terminal configuration in an emergency mode:

Nelson River bipoles 1 and 2 parallel operation

Itaipu bipoles 1 and 2 parallel operation.

As a result of upgrades undertaken to increase the power transfer capacity, parallel converters were added to each terminal of the Pacific Intertie effectively turning it into a multi-terminal system. The Pacific Intertie is currently operating with a singe converter per pole in one terminal and parallel converters in the other terminal. The Cook Strait HVDC link also underwent an upgrade where new converters were installed in one pole and the existing converters were reconnected in parallel on the other pole.

Most components in the HVDC stations within a multi-terminal system are not unique. When compared to a two terminal HVDC system, the control and protection systems are more complex and there is a greater dependence on the communication system between the terminals.

Theoretically any number of terminals can exist; however, the complexity of the control and protection systems as well as the amount of signal exchange required between terminals via the communication system will grow as the number of terminals increase.

Similar to two terminal HVDC systems, multi-terminal HVDC systems can be designed such that any terminal can operate as either a rectifier or and inverter. Power reversal of all terminals simultaneously can be done in a controlled manner similar to that of a two terminal system. Power reversal within a single terminal independent of the other terminals requires the use of reversing switches.

In the event of the loss of one pole in one terminal, the healthy pole in all terminals and the remaining terminals in the faulty pole can continue operation using ground return for the terminal with only one pole in service. The use of metallic return using an MRTB in the event of loss of a pole in one terminal of a multi-terminal HVDC systems is only possible if the converters in all terminals of the faulty pole are taken out of service.

One major performance issue related to multi-terminal HVDC systems is that a DC side fault or long lasting commutation fault in one terminal will impact all terminals resulting in the transient loss of 50% to 100% of transmission capacity. This is of particular concern if one terminal is relatively small in rating as compared to the other terminals, and more prone to commutation failures due to the strength of the AC system to which it is connected. Upon failing commutation due to a disturbance in its AC system, the small terminal will take the full DC current, interrupting the power flow in the main HVDC terminals. The potential negative impact of a small terminal on the overall HVDC system has made the application of small taps to an HVDC system unattractive in the past.

Valve Group Configurations within a Pole

The current trend in line commutated converter HVDC systems is that each terminal or each pole consists of one single twelve pulse converter rated for the full transmission voltage and current. The single valve group per pole configuration has been used in a number of schemes with ratings up to +/-500kV and 3000MW and is possible due to advances in thyristor technology. Use of a single valve group per pole provides a simple configuration, and with improved reliability of components, results in very high reliability of the overall system.

HVDC transmission systems with operating voltages above 500kV utilize multiple, series connected valve groups in order to attain the desired HVDC operating voltage. Use of series connected valve groups adds to the overall complexity of the system as it requires coordination of the number of valve groups in service at each terminal. In some instances series valve groups may be used to minimize the impact of the loss of a converter on the AC systems. With series connected valve groups, when one valve group is unavailable the other series valve group can remain in operation, enabling the continued transmission at a reduced DC operating voltage and correspondingly reduce power transfer capacity.

In some instances, valve groups have been connected in parallel to increase the current rating, and hence the transmission capacity, of a given HVDC system. This has typically only done in cases of upgrades to existing systems where upgrading the power transfer by increasing the HVDC operating voltage was not a viable option. Similar to the use of series connected valve groups, the use of parallel connected valve groups adds complexity to the overall system, requiring coordination of current orders between converters. In the event of the loss of one parallel connected valve group, the pole can remain in service at a reduced maximum DC current and correspondingly reduced power transfer capacity

HVDC Operating Voltage

For HVDC transmission systems utilizing only overhead transmission lines the operating voltage can be optimized, typically with the goal of minimizing transmission losses. Conductor selection is typically done based on corona and field effects or to minimize transmission losses rather than for thermal considerations.

Industry practise indicates that bipolar HVDC systems with a transmission voltage of 500kV or higher use bundled conductors, partially due to meeting the limits on corona effects. The selection of 400kV and 450kV transmission voltages does allow the use of a single conductor per pole from the point of view of corona effects, however the use of bundled conductors may still be preferable from the point of view of transmission losses. Use of a single conductor per pole may be required due to other considerations such as extreme icing conditions.

For HVDC transmission systems utilizing underground or undersea cables the operating voltage is usually dictated by the choice of the cable. Selection of a cable is based on the power transfer requirements, length of cable, and the current carrying capacity of the cable. Presently HVDC cables capable of operation at 450kV, 750A are available.

Reactive Power Requirements

The operation of an LCC HVDC converter results in a phase angle (ϕ) between the fundamental component of the currents and the phase voltages. As the firing angle (α) goes from 0 degrees (rectification) to 180 degrees (inversion), $\cos(\alpha)$ and hence $\cos(\phi)$ goes from positive to negative matching the reversal of AC real power; however $\sin(\phi)$, and therefore the corresponding AC reactive power, remains positive. This means that the converter will consume reactive power whether operating as a rectifier or an inverter.

The reactive power consumption of a typical converter operating at nominal firing angles will be in the range of 60% of the real power transfer. The reactive power consumed by the converter must be supplied from the AC system or using shunt capacitor banks, AC filters, or other forms of static or synchronous reactive power compensation. Typically the reactive power required by the converter is supplied by the AC filters and shunt connected capacitor banks.

As the power transfer through the converter increases, the amount of reactive power consumed also increases, therefore the reactive power compensation has to be managed in conjunction with the real power transfer. Typically large variations in the reactive power exchange with the AC system must be avoided, therefore when shunt elements are used, they must be switched appropriately. The size and the steps of the switched elements must also be selected to avoid excessive AC system voltage variations due to switching events given the strength of the AC system.

Staging Options

Possible staging options often used with LCC HVDC include the following:

Option 1 – Monopolar operation followed by bipolar operation

Stage 1 -Build bipolar line, insulate both poles to full DC voltage, rate conductors for full DC current, install converter capacity in one pole, operate as a monopole with metallic return at full DC voltage and full DC current

Stage 2 – Install converter capacity in second pole, operate as bipole at full DC voltage and full DC current

This option allows the deferral of cost of the converters for the second pole, however during stage 1 the loss of the pole results in the complete loss of transmission capacity, and the losses as a percentage of rated power are higher due to operation as a monopole with metallic return.

Option 2 – Bipolar operation followed by installation of additional series converter capacity

Stage 1 – Build bipolar line, insulate both poles to full DC voltage, rate conductors for full DC current, install one valve group per pole in both poles, operate as a bipole at reduced DC voltage and full DC current

Stage 2 – Install additional converter capacity by adding valve groups in series to those installed during stage 1, operate as bipole at full DC voltage and full DC current

This option allows the deferral of the cost of converter capacity until it is required, and the use of series connected valve groups minimizes impact of the loss of a valve group when operating in stage 2. Drawbacks of this option include that losses during stage 1 are higher as a results of operating at reduced DC voltage and full DC current, the addition of converters in series increases the overall complexity of the system as compared to one with a single valve group per pole, and the addition of series valve groups requires careful design and execution during stage 1 in order to ensure successful implementation of stage 2.

Option 3 – Bipolar operation followed by installation of additional parallel converter capacity

Stage 1 – Build bipolar line, insulate both poles to full DC voltage, rate conductor for ultimate DC current, install sufficient converter capacity in both poles at full DC voltage to meet initial requirements, operate as a bipole at full DC voltage and reduced DC current.

Stage 2- Install additional converter capacity by adding converters in parallel to the converters installed during stage 1, operate as bipole at full DC voltage and full DC current

This option allows the deferral of cost of converter capacity until it is required, and minimizes losses during stage 1, however drawbacks are similar to that for staging with series groups in terms of the added complexity and need for careful design and execution.

Overload Capabilities

The continuous overload capability of a LCC HVDC system is mainly determined by the ambient temperature and the capacity of the cooling system. The ability of the LCC converter to provide an overload is often utilized for mitigating the impact of the loss of a pole or for providing a degree of power modulation, even when operating at rated HVDC power.

The normal inherent continuous overload capability of an LCC converter is typically in the range of 10% with a potentially higher short term capability. In cases where it is required by the AC systems, additional short term or continuous overload capability can be made available at a cost. This is usually done in order to minimize the impact of the loss of a pole on the AC systems. Systems with short term overload capabilities of 2.0pu and continuous overload capabilities of 1.5pu have been contemplated.

Ground Electrodes

The ability to use ground return operation is dictated primarily by economic and environmental considerations. In cases where ground return operation is not allowed for environmental or other reasons, a dedicated metallic return conductor can be provided. The cost of providing a dedicated metallic return conductor and the losses incurred while utilizing the metallic return conductor significantly exceed the cost of providing ground electrodes and the losses incurred during ground return operation. This is particularly evident for long distance HVDC systems and systems including cable transmission.

Types of electrodes used in HVDC schemes can be loosely categorized as land, shore and sea types according to their installation locations. A land electrode can be either a shallow or deep burial type depending on ground conditions. Shore electrodes are divided into beach or pond electrodes, with beach electrodes located 10 to 50 m inside the waterline and pond electrodes located within a pond filled with sea water near the shore and protected by some form of breakwater. Sea electrodes are located further from shore.

The CIGRE 1998 Guide notes that sea and shore electrodes are generally preferred over land electrodes for the following reasons:

- there is less uncertainty with respect to achieving the required grounding since resistivity is better known,
- overheating of the electrode is not normally a concern.

Based on these criteria, sea electrodes would normally be favoured over shore electrodes. Other factors which make shore electrodes less attractive, particularly for beach installations, would be proximity to communities, accessibility by the general public, and aesthetics.

In general, when selecting an appropriate location for a ground electrode the following factors are taken into consideration:

- Ownership of the area, and the matter of obtaining permission to establish and operate the electrode at the intended site, including the use of land for shore-based installations in the case of a sea electrode.
- The characteristics of the site with respect to resistivity, moisture content, thermal conductivity, water exchange, and water depth.
- Potential electric field effects on converter station installations and the AC system, as well as metallic objects such as pipelines, cables, and other infrastructure.

Consideration of potential conflicting activities such as shipping or boating activities in the case of sea electrodes.

Potential influences on the marine environment, in the case of sea electrodes.

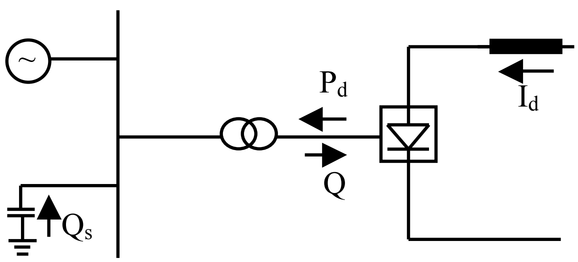
Cost considerations for alternative locations.

AC System Considerations

AC System Strength

The strength of the AC system, as indicated be the three phase short circuit MVA, plays a critical role in the operation of an LCC HVDC system, especially at the inverter. Figure 6-5 shows the typical connection of the inverter to the AC network.

Figure 6-5: Typical Inverter Connection



An inverter supplies DC power P_{dc} to the AC system and consume reactive power Q_C. Typically, most of the reactive power is supplied from the shunt banks (ac filters and capacitors) Q_S.

Two important quantities used in HVDC design are defined as follows:

$$\text{Short Circuit Ratio (SCR)} = \frac{\text{System MVA (S)}}{\text{DC Power (PDC)}}$$

and

$$\text{Effective Short Circuit Ratio (ESCR)} \frac{\text{System MVA (S)} - \text{Capacitive}}{\text{DC Power (PDC)}}$$

The ESCR provides an indication of the strength of the AC system and the expected performance of the LCC HVDC within the given AC system. ESCR has a bigger impact on inverter operation as compared to rectifier operation. Levels of ESCR are generally classified as:

Strong	ESCR > 2.5
Weak	2.5 < ESCR < 1.5
Very Weak	ESCR < 1.5

The ESCR impacts many performance factors such as the magnitude of Temporary Overvoltage (TOV), DC power recovery time and quality following AC and DC faults, and the stability of DC controls. It can be generally stated that overall performance degrades with decreasing ESCR. HVDC links can and do operate with very weak ESCRs, however these often require additional mitigation measures to provide acceptable performance of the integrated ac/dc systems.

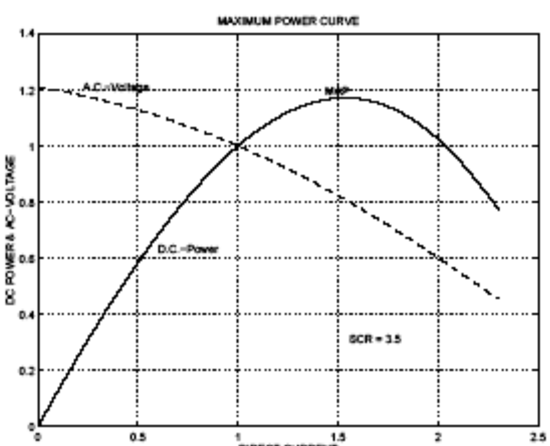
Other factors related to the AC system that must be considered include the AC system damping angle, which is the phase angle associated with the impedance of the AC system as viewed from the converter AC bus, and the AC system inertia. These factors influence the magnitudes of the temporary overvoltages (TOVs) within the AC system and the speed of recovery of the DC power transfer following faults.

Maximum Available Power

Figure 6-6 shows a typical Maximum Power Curve (MPC) which defines the relationship between DC power and current. The MPC at an inverter can be found by selecting an initial operating point (usually 1pu DC power, current and AC voltage) then varying the DC current while maintaining constant AC source voltage, shunt capacitance, converter transformer tap positions, and having the inverter operate at its minimum extinction angle. The rectifier is assumed to be able to provide the necessary DC current. The inverter AC bus voltage will change due to the variation in reactive power consumed by the inverter as it is further assumed that transformer tap changers, variable shunt compensation, and generator AVR action within the AC system do not have sufficient time to operate to provide regulation of the AC system voltage.

Figure 6-6 shows that as the DC current increases the DC power also increases, however a maximum is reached, which is referred to as the Maximum Available Power (MAP) point. As the DC current is increased beyond that corresponding to the MAP point, the DC power begins to decrease. This decrease in DC power is the result of the AC bus voltage being depressed due to the increased reactive power absorption by the inverter and the inability of the AC system to provide the necessary AC voltage support. For a given set of converter parameters and shunt compensation, the MAP depends on the AC system impedance.

Figure 6-6: Maximum Power Curve



Contingencies which occur with the AC system effect the system impedance, therefore for a given set of converter parameters and shunt compensation, AC system contingencies will result in a set of MPCs. In systems operating with high ESCRs, AC system contingencies are unlikely to result in operation where the desired DC power approaches the MAP point, however in systems operating with low ESCRs care must be taken to mitigate against the potential of voltage collapse.

Commutation Failure

Commutation failures most commonly occur at an inverter as a result of a sudden decrease in AC system voltage or a sudden shift in the AC voltage angle which result in a decrease in the voltage-time area for the commutation of current from one valve to another and the time for the outgoing valve to restore forward voltage blocking capability following conduction. Sudden changes in AC voltage or phase angle are more prevalent in weak AC systems.

A commutation failure will effectively result in the converter being short circuited, collapsing the DC voltage across the converter to zero and causing a surge in DC current. Typically the controls will act very quickly to increase the extinction angle and with continuation of the normal firing pattern the system will recover from the commutation failure.

From the AC system point of view a commutation failure results in a temporary reduction in power transfer. Operating experience shows that single commutation failures typically have no major impact on the AC system.

The likelihood of commutation failure can be reduced by increasing the nominal extinction angle at the inverter to provide an increase in the voltage-time area for commutation.

Temporary Overvoltages

Temporary overvoltages (TOVs) can occur at the AC converter buses as a result of blocking a converter, AC faults and DC faults. The severity of TOVs increases with decreasing ESCR.

TOVs can be created by the superposition of fundamental frequency and low order harmonic voltage components. The capacitive shunt compensation and high system inductance associated with systems with low SCR can result in a parallel resonance near second harmonic. The resultant harmonic voltage can be comparable to the magnitude of the fundamental during disturbances, producing an effective overvoltage exceeding two per unit.

Fault Recovery

Recovery of the HVDC system form AC and DC faults without subsequent commutation failure is a typical requirement for acceptable performance. Specific recovery times vary from one application to another and are defined by the AC system needs and characteristics.

Typically recovery to 90% of pre-fault HVDC power within 300ms of fault clearing would be considered as adequate. As the SCR decreases, the effects of magnetizing in-rush currents will become more pronounced and there may be the need to slow the recovery of the HVDC system , or to recover to a somewhat reduced HVDC power transfer.

The speed of recovery of the HVDC system also depends on the ability of the AC system to support the reactive power consumption requirement of the converter. Too fast a recovery may result in a depressed AC voltage which in turn negatively impacts the overall AC system recovery.

Slower recoveries are possible in situations where the AC system inertia is sufficient to maintain adequate stability margins.

Subsynchronous Oscillations

A number of instances have been encountered where the HVDC system was found to destabilize shaft torsional oscillations in thermal generator units. These subsynchronous oscillations were found to be the result of the constant current controls of the HVDC system, however interactions have also appeared in constant power control.

The highest negative interactions occur when the HVDC terminal is radially connected to a machine or group of machines. Interactions at frequencies above 20Hz do not appear to be a problem for a long distance DC line or cable scheme.

The addition of a subsynchronous torsional interaction control function within the overall HVDC controls has proven to be a very effective means of mitigation against these adverse interactions.

Mitigation of Performance Issues

Typical methods of mitigating potential performance issues, particularly those associated with operation in weak AC systems include:

- Increasing system short circuit level. This is typically done by the application of synchronous compensation.
- The application of a fast acting AC voltage control device such as a static var compensator
- The implementation of a control mode other than constant extinction angle control at the inverter which can provide AC voltage stabilization by either controlling AC voltage or DC voltage.
- Application of auxiliary HVDC control functions including such things as modulation controls, frequency controls, power swing damping controls, DC power runbacks, subsynchronous torsional interaction controls, etc.

Reliability Criteria (N-1)

According to the Transmission System Standards adopted by NERC, a single pole block is considered a Category B event which is an event resulting in the loss of a single element, comparable to the loss of a transmission circuit. A bipolar block is considered a Category C event which is an event resulting in the loss of two or more elements, comparable to the loss of any two circuits of a multiple circuit towerline.

Therefore in general, from a system reliability point of view, a single HVDC pole can be considered comparable to a single circuit AC transmission line and an HVDC bipole can be considered comparable to a double circuit AC transmission line on a common tower.

For a bipolar HVDC line to be fully comparable to a double circuit AC line on a common tower, a means for operating in monopolar mode must be provided. This can be accomplished either by using ground return (if allowed) or a metallic return conductor. If a dedicated metallic return conductor is provided then the HVDC bipole can, from a reliability point of view, be considered the same as a double circuit AC line on a common tower. However if a metallic return transfer breaker is provided to utilize the faulty pole's conductor as a metallic return, the reliability is not quite the same. This is because for a permanent fault involving the DC conductor of one pole, that conductor cannot be used as a metallic return for the healthy pole. Under such circumstances the healthy pole can only continue to operate with ground return, and if continuous operation is not permitted in ground return then the power transfer on the healthy pole will also be affected.

Multi-Infeed Aspects

As situations arise with multiple HVDC systems terminating in close proximity within a common AC system become more common, the need to consider the interactions between the HVDC systems becomes more prevalent. The characteristics of the individual HVDC systems and how they interact defines the overall performance of the integrated ac/dc systems and is particularly true in situations where two or more inverters are located in close proximity.

The interaction phenomena between two inverters includes:

Temporary Overvoltage

Commutation failure and fault recovery

Harmonics

Control interaction and power/voltage instability.

CIGRE working group B4.41 entitled “Systems with Multiple DC Infeed” has been working to identify potential multi-infeed issues and have defined several indices that can be used to quantify the degree of interaction that exists between the multiple HVDC systems.

The Multi Infeed Interaction Factor (MIIF) has been developed to provide an indication of the relative change in the AC voltage at one bus (j) for a small change in voltage at a second bus (i) and is defined as:

$$MIFF_{i\,I} = \frac{V_i}{V_i}$$

MIIF values vary from one for inverters located at a common bus to zero for inverters which are far apart and provides an indication of the electrical closeness of the inverters.

In addition to the MIIF, the concept of ESCR has also be extended to a Multi Infeed Equivalent Short Circuit Ratio (MIESCR) which for a new HVDC link to be located at bus i is given by:

$$MIESCR_i = \frac{SCC_i - Of_i}{Pdc_i + \Sigma_i\,(MIIF_{i\,i} * Pdc_i)}$$

Current Trends in LCC HVDC

The current trend in line commutated converter HVDC systems is that each pole consists of one single twelve pulse converter rated for the full transmission voltage and current. The single valve group per pole configuration has been used in a number of schemes with long distance overhead transmission lines with ratings up to +/-500kV and 3000MW.

These systems take advantage of the latest developments in thyristor technology which have achieved voltage ratings of 8 to10kV and continuous current ratings of 4 to 6kA for an individual thyristor. Both electrically triggered and directly light triggered thyristors are available and have been operating successfully.

When determining which type of thyristors to use, the supplier will choose the thyristor that best suits the current rating, while minimizing the number of elements required in series to meet the required DC voltage. Higher thyristor voltage ratings mean a thicker silicon wafer. For a given area and current, the increase in thickness means higher losses and reduced surge current capability. In addition, increased DC current demands result in higher valve short circuit current. These requirements have led to the development of larger diameter devices with a larger wafer area.

HVDC systems with cable lengths of up to 580km, operating at a DC voltage of +/-450kV and with a power transfer capability of 700MW are currently in-service. The cables are most commonly mass impregnated and in the case of monopolar, metallic return systems, cables with an integrated return conductor have been used.

Converter transformers are a critical component of HVDC stations. There are a number of possible configurations, however as power levels have increased, the one most commonly used is the single phase, three winding design. Major factors which influence the type of design include: ratings, size, weight, and reliability concerns. Due to the extensive potential outage resulting from the failure of a converter transformer, it is common to require a spare unit to be provided at each station.

Reactive compensation for LCC HVDC systems is, in most cases, provided by the shunt connected AC filters and supplemented by shunt connected capacitors. Reactive power exchange with the AC systems is generally limited to a narrow band in order to avoid negatively impacting the AC systems. In some cases fast acting reactive power compensation has been provided by static var compensators or STATCOMs in order to provide reactive power support for the HVDC converter and simultaneous regulation of the AC bus voltage.

In cases where the short circuit level is low, synchronous compensators have typically been used to increase the short circuit level of the AC system and provide reactive power support for the HVDC converter. A by product of the addition of synchronous compensators is the accompanying increase to system inertia. Recent advances in vertical shaft synchronous compensator design allow the application of high inertia machines which can provide substantial support to system inertia in cases of small, isolated AC systems.

Extensive studies have been undertaken to investigate potential long term impacts of electrode operation. These studies have shown that with suitable mitigation measures, electrode operation has little or no impact, however, in order to avoid potential delays in the project regulatory process there has been a growing tendency to avoid electrode operation. This is evident in a number of monopolar systems which have been built with a dedicated metallic return conductor. This trend seems more prominent in subsea cable systems.

Ultra-High Voltage DC (UHVDC)

Although no systems are currently in operation at DC voltages higher than +/-600kV recent advances in Ultra High Voltage DC (UHVDC) technology have resulted in HVDC systems being planned and in the execution phase with operating voltages of +/- 800 kV and power transmission levels in the range of 6000 MW per single bipolar line. Advances in UHVDC technology have been fuelled by the need to transmit large quantities of power across long distances in combination with greater difficulties in securing transmission line right of ways. For the purposes of this discussion the term UHVDC will be used to describe HVDC systems whose operating voltage is 800kV.

UHVDC Configurations

In order to achieve the high power transfer levels required, UHVDC systems will require multiple valve groups per pole, connected either in series or parallel.

Series connection of two valve groups in a pole would have the following benefits and drawbacks:

- Only one of the valve groups would need to be insulated for 800 kV, the other would only need to be insulated for 400kV;
- only one of the four converter transformers required in the pole would have to be insulated for 800 kV, the others would be insulated for 200kV, 400kV and 600kV;
- the loss of one series conneted converter would result in the capability to transmit half the pole with balanced currents between poles avoiding ground return, however the voltage level in that pole would only be half of the nominal, resulting in higher losses;
- because of the likely long distance of the transmission system, staged development with the first stage operating at 400kV for an extended period of time would not be practical due to the higher losses.

Parallel connection of two valve groups in a pole would have the following benefits and drawbacks:

- Both of the valve groups would need to be insulated for 800 kV;
- two of the four converter transformers required in the pole would have to be insulated for 800 kV, the other two would be insulated for 400kV;
- the loss of one parallel connected converter would result in the capability to transmit half the pole power but would require the use of ground return due o the imbalanced currents in the two poles, however losses would be lower than in the series connected configuration;
- staged development with instillation of one converter per pole would be possible as operating would be at 800kV and losses would be acceptable.

UHVDC Challenges

Although systems operating at 500kV and 600kV have been operating satisfactorily for many years the extension to operation at 800kV is not without its challenges.

Transmission Lines

Specific issues related to transmission line design for 800kV operation include corona, radio interference, audible noise, air clearances and insulator performance. Of these issues the most challenging appears to be insulator performance and in particular the effect of pollution on the switching surge withstand levels.

Converter Transformers

Converter transformer performance continues to be a topic of discussion in existing HVDC systems and therefore converter transformers and their bushings are viewed as critical items in the application of UHVDC technology. The concerns relate to the presence of DC stress and combined AC and DC stress on oil/paper spaces and chemical interactions.

Bushings

The performance of bushings and the effect on pollution on their performance along with concern for internal stresses and longevity are also a concern for 800kV applications. Current trends in HVDC indicate that non-ceramic bushings will be prevalent in 800kV applications.

Converters

Converters used in UHVDC applications will be similar to those currently in use and as such do not pose any significant challenges as such. Currently thyristors with ratings of 8-10kV and 3-4kA are available and applicable to UHVDC systems.

AC System Impacts

Perhaps the greatest challenge to the application of UHVDC technology will be the ability to successfully integrate the UHVDC system into the AC systems. Concerns related to the impact of the loss of power associated with the loss of a converter or a pole, potential overvoltage issues, AC system voltage regulation, etc. must be addressed. Concepts similar to those used for existing HVDC systems such as ESCR provide insight into the potential magnitude of these issues. For example if a minimum ESCR of 2.5 is required, a 6000MW UHVDC system would require that the AC system strength be in the range of 18,600MVA.

Current Trends in UHVDC Technology

UHVDC is a newly emerging application of the mature LCC HVDC technology and much of the proven technology is being applied to UHVDC. Technical challenges related to insulation levels and the size and weight of components (in particular the converter transformers) have been, and continue to be addressed. The Xiangjiaba – Shanghai HVDC link with a rating of +/-800kV, 6400MW and a transmission distance of 2700km is the first UHVDC system. The link uses two series connected valve groups per pole and is planned to be commissioned in 2010.

Voltage Source Converter (VSC) HVDC

VSC technology for HVDC power transmission applications has advanced quickly from the Hellsjőn project with a rating of 3 MW in 1997 to the Transbay Cable Project with a rating of 400 MW which is planned to be in service in 2010. Currently VSC HVDC technology with ratings of up to1100 MW operating at +/- 320 kV with an overhead line is available.

Voltage source converters employ state-of-the-art turn on/turn off Insulated Gate Bipolar Transistor (IGBT) power semiconductors. As a conducting device, the bipolar transistor with its low forward voltage drop is used for handling high currents. Instead of the regular current-controlled base, the IGBT has a voltage-controlled capacitive gate, as in a MOSFET device. I.

Unlike thyristor based LCC valves which can only conduct DC current in one direction, IGBT based VSC valves are bi-directional. As power reversal in a VSC HVDC system does not require reversal of the voltage polarity, VSC HVDC can be used in conjunction with cables that have extruded polymer insulation which provide a cost effective alternative to cables associated with conventional LCC HVDC.

The major factor in determining the rating is the IGBT turn-off current capability. Presently IGBTs are available with a turn-off current capability in the range of 1800A.

VSC HVDC technology is currently commercially available from two of the leading suppliers of HVDC under the trade names HVDC Light from ABB and HVDC Plus from Siemens. Other suppliers are currently developing VSC technology for application to HVDC however they are not yet widely available on a commercial basis.

Application of VSC to HVDC

The application of VSC to HVDC transmission was initially limited to cable installations. This was partially due to the fact that a VSC can be used with extruded polymer insulated cables which provide cost savings when compared to conventional LCC HVDC, and partially due to technical challenges associated with faults on the DC circuit. The bi-directional nature of the VSC valve means that currents from the AC side will flow into a fault on the DC circuit, requiring the entire converter to be tripped to allow fault clearing making automatic restart nonviable. Since faults on the DC side are not common for a cable installation, and when they do occur they are faults for which automatic restart is not required, this limitation was not an issue for cable projects.

Recent advances have made the first application of VSC to an overhead transmission line possible. The Caprivi project includes a 970km overhead line and is designed to operate at a DC voltage of +/-350kV with an ultimate rating of 2x300MW. The first stage of the project, a monopole rated at 300MW is planned to be in service in late 2009. The development and application of a high speed HVDC circuit breaker will allow a DC line fault to be cleared quickly and the converters restarted within about 500ms.

Table 6-1 lists of some of the major VSC systems presently in service or under development.

Table 6-1: Sample of VSC HVDC Systems Currently in Operation or Under Construction

System	Year	Rating (MW)	Voltage (kV)	Transmission	Application
Gotland	1999	50	+/- 80	2x70km cable	Wind farm connection
Directlink	2000	180	+/- 80	6x65km cable	Interconnection for power trading
Cross Sound	2002	330	+/- 150	2x42km cable	Power infeed to urban area
MurrayLink	2002	200	+/- 150	2x180km cable	Interconnection for power trading
Estlink	2006	350	+/- 150	2x105km Cable	Interconnection for power trading
NordE.On 1	2009*	400	+/- 150	2x200km	Offshore wind farm connection
Caprivi	2009*	300/600	+/-350	970km overhead line	Bulk power transfer
Transbay	2010*	400	+/- 200	88km cable	Interconnection for power trading

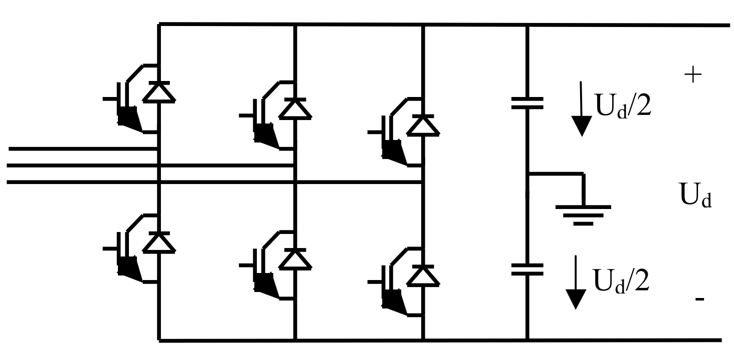
* Planned commissioning date.

VSC for HVDC

Two-Level and Three-Level Converters

The basic topology of a two-level VSC using IGBT switches is shown in Figure 6-7. It consists of six IGBT valves, with two IGBT valves connected to each phase terminal – one between the positive potential and the phase terminal, and the other between the negative potential and the phase terminal. Each IGBT valve is provided with a diode connected in anti-parallel to allow bidirectional current flow. Two equally sized capacitors are placed on the DC side to provide a source of reactive power.

Figure 6-7: Basic Configuration of a Two Level Converter



High speed switching control is achieved through high frequency pulse width modulation. The output wave is chopped and the width of the resulting pulse is modulated. Undesirable harmonics in the output waveform are concentrated to a narrow bandwidth resulting in a reduction in filter requirements.

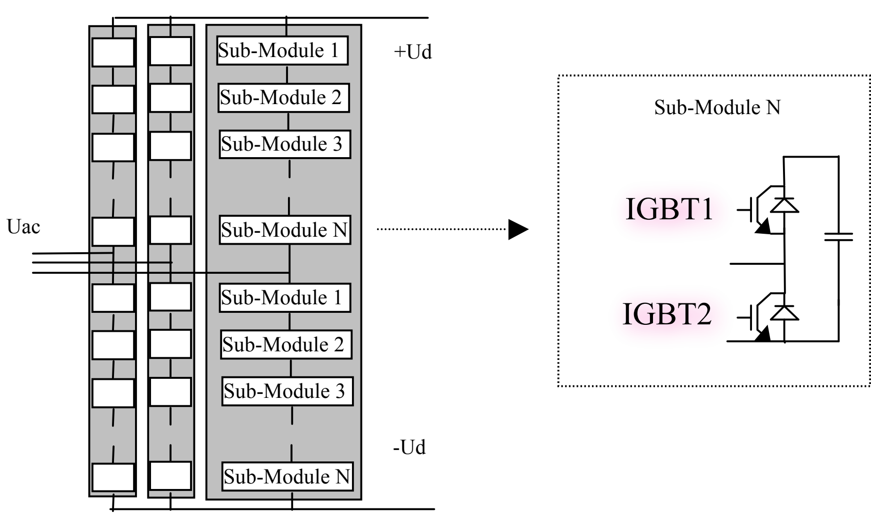
As an alternative to the two level converter which produces DC voltages at two discrete levels, the three level converter can produce a positive and negative DC voltage to ground. The control strategy for a there level converter is more complicated than for a two level converter, however it provides a faster control response, less harmonics for a given switching frequency, and provides a higher capacity than a two level converter.

Multi-Level Converter

The basic topology of a multi-level converter is shown in Figure 6-8. The multi-level converter includes individual module capacitors that are uniformly distributed throughout the topology. Each level is individually controlled to generate a small voltage step; in this way, each module within the multilevel converter is a discrete voltage source in itself with a local capacitor to define its voltage step.

In this arrangement there are three identical phase units each comprising two multi-valves where each multi-valve contains a sufficient number of modules to support the full DC voltage, Ud.

Figure 6-8: Basic Configuration of a Multi-Level Converter



Switching control of the multi-level converter is done using Pulse Width Modulation, however lower switching frequencies can be used (in the range of three times fundamental frequency) reducing the switching losses.

Transformer

Unlike conventional LCC HVDC which requires specialized converter transformers, the transformers used with VSCs can be ordinary power transformers. This is because the VSC generates an AC voltage with zero DC voltage offset with respect to ground potential; which reduces the insulation requirements across the transformer converter windings. Furthermore, the VSC produces nearly sinusoidal currents therefore the transformer does not need to be designed to handle the stresses and losses associated with high harmonics.

VSC HVDC Cables

Since power reversal in a VSC HVDC system does not require the DC voltage polarity reversal, VSC HVDC can be used with extruded polymer insulated cables which provides a cost effective alternative to mass impregnated or oil filled cables normally associated with LCC HVDC transmission. The cables have polymeric insulating material which is very strong and robust meaning that submarine cables can be laid in deeper water and on a rougher seabed, while land cables can be installed less expensively with a ploughing technique.

AC Filters

AC filters are provided in order to reduce the harmonic content on the AC bus. The magnitude of the harmonic EMFs will vary with the DC voltage and the switching frequency, but it will also depend to some extent on the PWM technology of the converter. Filter configurations will depend on the performance requirements for a given systems. Typical filter sizes are in the range of 10% to 30% of the rated power.

Performance of VSC HVDC

The basic performance benefits offered by VSC HVDC as compared to conventional LCC HVDC technology include:

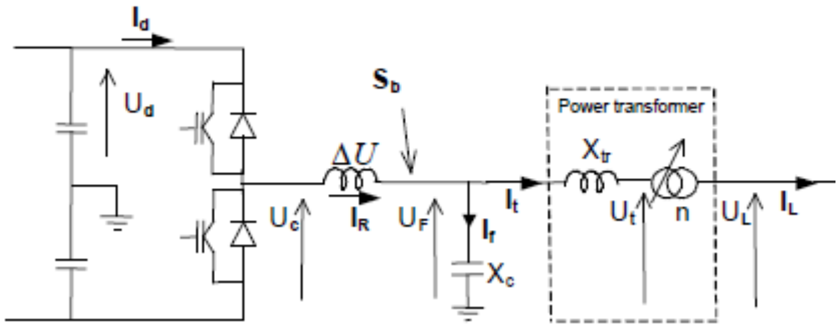
- Rapid control of active and reactive power independently
- Operation with short circuit ratios down to zero
- Immunity from commutation failures caused by disturbances or distortions in the AC systems
- Black start capability.

Real and Reactive Power Control

Due to the ability to fully control the turn on and turn off of the IGBT devices, a VSC is able to both absorb and generate active and reactive power independently up to the converter rating. Furthermore the VSC output currents can be varied over the complete operating range in a smooth, linear fashion, making operation down to zero DC current possible.

Figure 6-9 shows a simplified circuit diagram for a two level VSC converter.

Figure 6-9: Simplified Circuit Diagram of a Two Level Converter[30]



When looking at the connection point of the AC filter, the real and reactive powers are given by the following equations:

$$P = \frac{U_f * U_c * \sin\delta}{\omega L}$$

$$Q = \frac{U_f * (U_f - U_c) * \cos}{\omega L}$$

Where:

d = phase angle between the filter voltage U_f and the converter voltage U_c

L = inductance of the converter reactor

From the above, it can be seen that the real power flow can be controlled by changing the phase angle, and the reactive power flow can be controlled by changing the amplitude difference between the filter voltage (U_f) and the converter voltage (U_c).

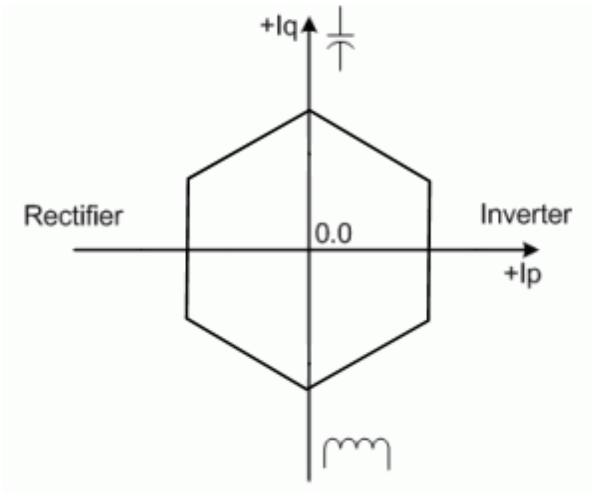
If the converter voltage phase lags the filter voltage power flows from the AC side to the DC side (rectifier operation). If the converter voltage phase leads the filter voltage, power flows from the DC side to the AC side (inverter operation).

If the filter voltage is greater than the converter voltage, the converter consumes reactive power. If the filter voltage is less than the converter voltage, the converter produces reactive power.

Switching control allows the creation of any phase angle and any amplitude within the rating of the converter by changing the PWM pattern. This offers the ability to independently control both the active and reactive power of a converter. Figure 6-10 shows a typical P/Q diagram which is valid within the entire steady state AC network voltage range.

[30] “It’s Time to Connect, Technical Description of HVDC Light Technology”, Technical brochure issued by ABB AB, Grid Systems – HVDC, SE-771 80 Ludvika, Sweden.

Figure 6-10: Typical P/Q Diagram



AC Faults and Commutation Failures

Since a VSC converter does not rely on the AC system voltage for valve turn off, it is not susceptible to commutation failures due to depression or distortion of the AC bus voltage. A VSC HVDC system will be able to transmit a reduced amount of power during a fault in the AC network, with the amount of power transmission dictated by the severity of the voltage depression. Furthermore, the power recovery following fault clearing will likely be improved.

DC Faults

Because of the bi-directional nature of the IGBT valves, a fault occurring on the DC side of the converter will be fed from all AC systems connected to the DC line. Significant fault currents may be drawn from the AC systems. The fault current will depend on the strength of the AC system itself and the combined impedance of the VSC transformer, phase reactors, DC smoothing reactors and the DC line impedance between the VSC terminal and the fault location.

In addition, the AC voltage at each VSC converter terminal will be reduced until such time as the DC fault can be cleared. The severity of the voltage depression will again depend on the AC system strengths and the impedance to the fault location.

The capacity to supply power to the receiving end system will be significantly reduced during the DC fault. In the case of a bipolar system, power transmission will be stopped on the faulted pole due to the DC fault itself and reduced on the healthy pole due to the depression in AC system voltages.

When a DC fault occurs, the IGBTs themselves can be switched off before the fault current can reach a critical level, effectively protecting the IGBTs. Current will however continue to flow from the AC system into the fault through the anti-parallel diodes within the valve. Interruption of the fault current and eventual clearing of the fault requires isolation from the AC systems.

In earlier applications VSC converters were used only in conjunction with HVDC cables. Since a fault on the cable is rare and the cable does not recover from such a fault, the acceptable response to a DC fault was to open the main AC circuit breakers located on the AC system side of the VSC transformer and automatic restart was not required.

As DC faults are more frequent with overhead DC line applications, and automatic restart from such faults is a requirement, a sequence of AC and DC breaker operation is required to clear the DC line fault and restart the VSC HVDC transmission. In an LCC HVDC system, DC line faults are cleared by reducing the DC current to zero through control action, waiting for the required de-ionization time, then restarting transmission without the need to operate any mechanical devices.

Based on information provided by ABB, the DC line fault clearing sequence for HVDC Light converters connected pole to neutral is as follows (timings are sequential and cumulative, but approximate):

DC line fault detection +10 ms

open AC and DC breakers at all stations connected to the faulted pole +50 ms after fault detection. The AC breaker clearing time of +50 ms removes the fault current source, the DC breaker clearing breaks the DC line current transient to begin the deionization time

DC line fault deionization time + 250 ms

close AC breakers with damping circuit to re-energize converters +100 ms

close DC breakers to re-energize DC line pole + 50 ms

deblock converters to restart the power flow + 30 ms

The total time to clear the DC line fault and restart transmission is estimated to be 490 ms.

Additional Performance Features

Additional performance features of VSC HVDC include:

Continuously variable power from full power in one direction to full power in the reverse direction.

No minimum power level, VSC HVDC transmission can operate at zero power transfer.

Control of reactive power is independent of real power therefore even when the converter is transmitting zero real power it still has its full range of reactive power generation and consumption.

VSC HVDC transmission provides a means to control voltage and stabilize frequency during grid restoration. Frequency control is not limited in the same way as a conventional power plant, and full black start capability is possible.

Overload

Because the principle factor in the rating of a VSC is the level of current that can be turned off by the IGBTs, and typically the DC current is maximized to reduce overall transmission losses, a VSC does not provide any inherent overload capability. Therefore if a VSC HVDC system requires an overload capability it can only be provided by increasing the nominal rating of the converter.

Environmental Aspects

Environmental aspects of VSC HVDC transmission include:

- VSC converters require less space per MW installed as compared to conventional LCC converters.
- VSC converters use an indoor design which reduces the risk of flashover. Stations resemble industrial buildings with minimal outdoor switchyards.
- Audible noise is also greatly reduced.
- Ability to use cost effective polymer insulated cables makes the use of cable transmission more cost effective, potentially eliminating the need for overhead lines.

Application to Small Taps

A major impediment to the application of small taps to HVDC systems using conventional LCC technology is that a commutation failure in the small tap results in the momentary interruption of the power transfer in the main HVDC terminals. Typically, a small tap would be connected to a weak AC system which would be prone to commutation failures. In addition the rating, location and recovery rate of the tap are limited due to stability issues.

Due to its immunity to commutation failures caused by disturbances in the AC system, a small VSC tap would not have the same impact on the overall HVDC system. Furthermore there would be less limitations on the rating and location of the tap, and due to the reactive power control inherent with a VSC converter, the tap could provide AC voltage support and stability within the typically weak AC system to which it is connected.

Current Trends in VSC HVDC

VSC cable transmission with ratings of +/-200kV and 300MW is currently available in conjunction with polymer insulated cables. The Caprivi Project which is planned to be in service in 2009 represents the first application of VSC HVDC with an overhead transmission line, with a rating of+/-320kV, 1100MW.

Other applications for VSC based HVDC include connection of large scale wind farms, the supply of isolated remote loads, and the supply of offshore platforms.

Continued development of IGBT technology, and in particular the current turn-off capability of the IGBT will allow for increased power transfer capabilities in the future. Current trends indicate that bipolar transmission with ratings of 2000MW, +/-640kV should be available in the near future.

Polymer insulated cables suitable for use in VSC HVDC transmission up to 320kV have been successfully type tested. Development of cables with higher voltage and current levels is expected.

As more suppliers enter the market, it is expected that VSC capabilities will continue to expand while costs will reduce due to increased competition.

Reliability Criteria (N-1)

According to the Transmission System Standards adopted by NERC, a single pole block is considered a Category B event which is an event resulting in the loss of a single element, comparable to the loss of a transmission circuit. A bipolar block is considered a Category C event which is an event resulting in the loss of two or more elements, comparable to the loss of any two circuits of a multiple circuit towerline.

Therefore in general, from a system reliability point of view, a single HVDC pole can be considered comparable to a single circuit AC transmission line and an HVDC bipole can be considered comparable to a double circuit AC transmission line on a common tower.

For a bipolar HVDC line to be fully comparable to a double circuit AC line on a common tower, a means for operating in monopolar mode must be provided. This can be accomplished either by using ground return (if allowed) or a metallic return conductor. If a dedicated metallic return conductor is provided then the HVDC bipole can, from a reliability point of view, be considered the same as a double circuit AC line on a common tower. However if a metallic return transfer breaker is provided to utilize the faulty pole's conductor as a metallic return, the reliability is not quite the same. This is because for a permanent fault involving the DC conductor of one pole, that conductor cannot be used as a metallic return for the healthy pole. Under such circumstances the healthy pole can only continue to operate with ground return, and if continuous operation is not permitted in ground return then the power transfer on the healthy pole will also be affected.

6.3 CURRENT STATUS OF AC TRANSMISSION

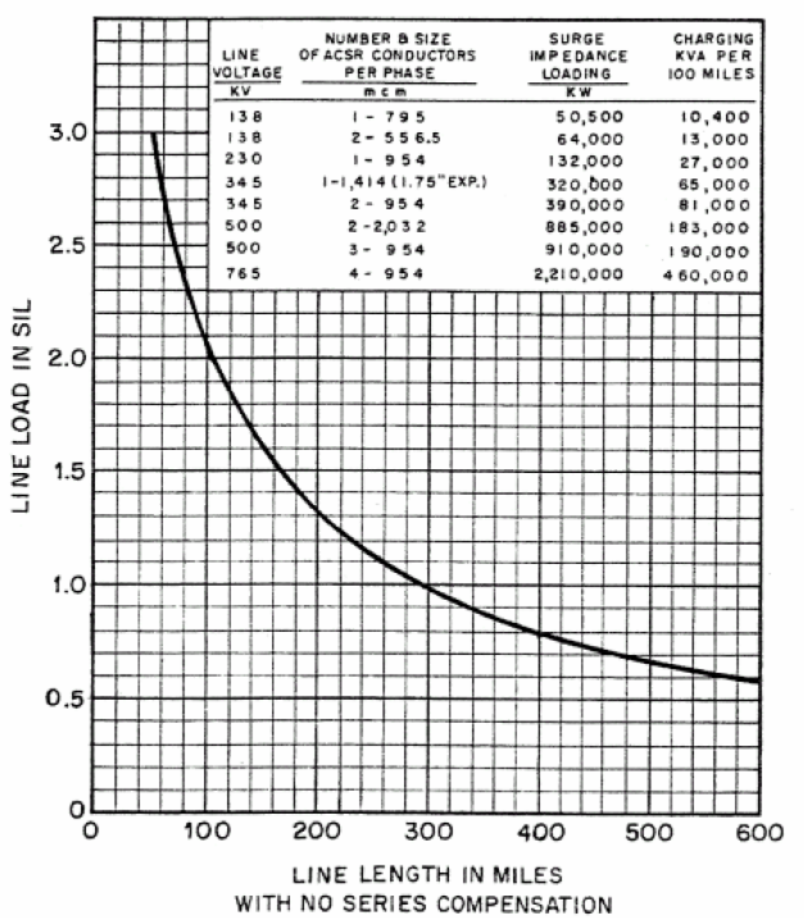
Introduction

This section presents a high level comparison of transmission technology options for the required power transfer level of 3000 MW (1000 MW of which would be used by WSP) across a transmission distance of 1400 km (870 miles). The amount of power to be transmitted and the distance are key factors for selecting the transmission technology option (HVDC versus EHV AC) and/or transmission voltage level. The right-of-way requirements for each transmission option are also very crucial in finalizing the feasible transmission options.

Loadability of EHV AC Transmission Lines

The power transfer capability (loadability) of EHV AC transmission lines over long distances is limited by factors other than the thermal ratings of conductors. The major factor that reduces the loadability of lines is the transient stability of the overall resulting system. Primarily, two factors dominate the loadability, namely, the line reactance (depends upon the distance) and the sending and receiving system reactances (system strengths). Figure 6-11 3-1 shows the well known St. Clair curve which represents the transmission line loadability in terms of MW for various distances irrespective of the voltage level. The loadability for a given distance in the St. Clair curve is based on thermal limitations, voltage drop and steady-state stability limit. In this figure, the y-axis represents the line load limit in per unit of its Surge Impedance Loading (SIL), and the x-axis represents the transmission distance.

Figure 6-11: Transmission Line Loadability (St. Clair) Curve



It is noted that the SIL loading of a transmission line is 1.0 SIL for a transmission distance of 300 miles. A transmission line loaded at 1.0 SIL neither consumes nor produces reactive power. As the load exceeds 1.0 SIL, the line consumes more reactive power than what it can produce, while at loadings below the SIL the line produces more reactive power than what it consumes. For long transmission lines, thermal rating is not a limiting factor. The power transfer capability of a long line becomes limited due to reactive power consumption, voltage control and stability issues. The reactive compensation of long transmission lines to mitigate the Ferranti effect due to charging is a serious issue when looked at from the system perspective. The typical SIL loadings of standard 500 kV and 765 kV transmission lines are given below:

Voltage, kV	SIL [MW]	Typical Thermal Rating [MW]	Line Charging [Mvar/mile]
500	950	2600	1.9
765	2200	5400	4.6

The St. Clair curve provides the power transfer capability of an un-compensated transmission line, beyond which it is enhanced by employing series compensation. In a series compensated line, the increase in the amount of power transfer depends upon the amount of compensation and with normally applied compensation levels, the transfer level could be increased by as much as twice that of the uncompensated lines. Although series compensation increases the loadability (the so called effective surge impedance loading) of a line, the length of line can still become a serious constraint and decisive factor in selecting the transmission voltage level.

Keeping in view bulk power transfer levels of 3,000 MW and long distances involved across Canadian provinces to form a National Grid, 500 kV and above voltage levels are the only choices that need to be considered for development. For instance, 765 kV AC or ±500 HVDC between Winnipeg and Ontario would involve distances of over 1400 kilometres and would call for consideration of 765 kV or higher voltages Besides, the terminal stations at both ends, a couple of intermediate switching stations would be required due to line loadability and voltage control issues.

EHV and UHV Transmission Technologies

The 765 kV and 800 kV EHV AC transmission technologies are the highest established voltage classes in commercial operation in the world today. Its electrical power-carrying capacity for lines longer than 100 miles, commonly measured by power engineers using the concept of SIL discussed above. Past research and experience indicate that the load-carrying ability of a transmission line (loadability) is highly dependent on the line length due to increased reactance.

For instance, St. Clair curve of Figure 3-1 shows that the loadability of a 550-mile-long transmission line is merely 60% of surge impedance loading. For a 765 kV line, this translates to 1400-1500 MW, i.e., only about one-third of its projected thermal capacity. In order to increase the loadability of this line, a static var compensator (SVC) with an estimated control range of -500 Mvar to +1000 Mvar may be installed at the intermediate station and at the end terminals of the line. Twin thyristor-controlled reactors (TCRs) and twin thyristor-switched capacitors (TSCs) comprising the SVC dynamic control range are normally included in the latest SVC design, along with automatic sectionalizing capability, to allow prompt isolation of any failed component in the SVC. By providing the required dynamic voltage regulation and firming up the receiving systems, these SVCs will reduce the effective transmission distance to less than 300 miles, thus boosting the loadability by 80% to about 110% of SIL, or above 2600 MW.

Series Capacitor Compensation of EHV and UHV Lines

Line loadability of EHV or UHV lines can be increased by employing series capacitor compensation. In any long distance transmission system, a controlling factor for power transmission is the inductive reactance of each section of transmission line. The use of a bundled conductor serves to reduce this significantly, (even though use of a bundle may be required for other purposes). Series capacitor compensation is a proven technology to further reduce line reactance, i.e., effectively reducing its line length.

Decreasing reactance of the line can increase power transfer through a transmission line. Adding capacitors in series with the line can decrease the reactance of the line. Series capacitors or compensation is an effective and economical way to increase power transfer capacity in a given transmission corridor. These devices are connected in series and compensate for the inductive reactance of the line. This reduces the reactance of the line and the lines can be loaded at a higher level without compromising the stability of the system. Besides improving the loadability of the lines, better voltage control can also be achieved with series compensation.

In essence, a capacitor is placed in series with each of the 3 phase wires of the line such that the reactance of the capacitor annuls some portion of the reactance of the line. For instance, with 50% series compensation the capacitor reduces the line reactance to 50% of its natural value, and can significantly increase the line loadability. Usually compensation of the order of 50 – 70% of the inductive reactance of the line is used depending on the power transfer requirement. Special protection schemes are also required to protect the series capacitors in case of a fault.

Capacitors may be placed at any point in a line, or at a substation between sections of line, although, it is common practice to place them near the middle of the line. This assists in ensuring reliable protection both to the line and to the capacitor from lightning and other faults. Capacitors installed near substations make line protection more difficult and costly and inherently less secure. Capacitors are mounted on platforms insulated from the earth by post insulators. Recent developments in capacitor bypassing equipment has led to sharply increasing application for series capacitors all over the world.

The amount of series compensation that can be used is limited by serious sub-synchronous resonance phenomena, which must be studied where series capacitor compensation over 40 to 50% is envisaged. The addition of series capacitors may cause sub synchronous resonance problems and damage the shaft of a turbine generator. However, a Thyristor-based controller has recently been developed to damp the sub synchronous oscillations. Issues like sub synchronous resonance are also investigated before implementing series compensation at any place in the system. Addition of series compensation can result in increased losses in the corridor due to the increased power transfer. The use of Thyristor controlled series capacitor will allow control over the level of series compensation and can improve the damping of the power system.

UHV Transmission Technology

The 1200kV AC technology is being developed in India as next higher AC voltage for bulk power transfer over long distance, which would be the highest AC voltage level in the world. Development of this technology is considered to go a long way for strengthening of National Grid capacity to take care of long-term power transfer requirement of the country. In order to develop this 1200kV AC technology in India, POWER GRID of India and many manufacturers are collaborating to establish a 1200kV UHV AC Test Station at Bina. A 1200 kV test line is being constructed along with two 1200 kV test bays in which the leading local transmission lines and substation equipment manufacturers are providing major equipment like transformers, surge arresters, circuit Breakers, CTs, CVTs and transmission line hardware etc.

Stability Issues

The power transfer capability (loadability) of EHV or UHV AC transmission lines over long distances is limited by factors other than the thermal rating of the conductors. The major factor that reduces the loadability of lines is the line reactance and in turn transient stability of the overall resulting system, as quantified below.

Transient stability is defined as the ability of the generators in the power system to remain operating in synchronism, when subject to a severe transient electrical disturbance. Short circuits of conductors on a power line, for example would lead to such a disturbance, resulting in large excursions in the speed and electrical power output of the generators and the generators must be capable of returning to synchronous speed.

The steady-state operation of the planned power system must also be assured to meet the stipulated planning and operating criteria, and should be evaluated by load flow simulations of the planned power system. The loadability of the planned systems limited due to transient stability (under disturbance conditions), should be evaluated by simulation of the electromechanical phenomena that occurs in the power system following a system short circuit or fault.

The transient stability performance of the system and in turn loadability of long EHV lines can be improved by employing the switched-Thyristor technology that provides a variable amount of series compensation instantaneously, by use of high power Thyristor switching of the associated capacitor banks. The second option, Thyristor controlled shunt capacitors, provides a variable amount of shunt compensation instantaneously. Both the series and the shunt Thyristor compensation devices can be quite effective in improving power system stability. Braking resistors that are inserted to absorb generating unit kinetic energy following a system fault, while effective, poses some risks due to the resulting shocks to the turbine shaft system.

Steam Turbine fast valving can be quite effective by temporarily reducing the mechanical power input but is more appropriately considered to overcome situation such as delays in implementing the transmission system.

Voltage Control Issues

Long EHV transmission lines pose voltage control challenges due to the flow of line charging (capacitive) current through the line inductance. This line charging current phenomenon raises voltage profile of the line which is referred to as Ferranti effect. In practice, following a sudden opening of the line at the receiving end, the sending end voltage will rise due o capacitive current flowing through the line. Appropriate forms of reactive power compensation (reactors) need to be provided on long lines to keep the rise in voltage to acceptable levels.

Typically, an intermediate switching station with appropriate reactive power compensation is needed after every 400 to 500 km line section of a 1400 km long EHV line due to voltage control issues at midpoint of the transmission line during normal operation and at terminal stations, especially when one of the line opens.

FACTS and Other Devices

FACTS products are assemblies of other power system products that contain arrays of power electronic switches and are controlled by a digital signal processor. The names of these products are related to the primary function that the product is to perform and a number of different products can have many of the same components.

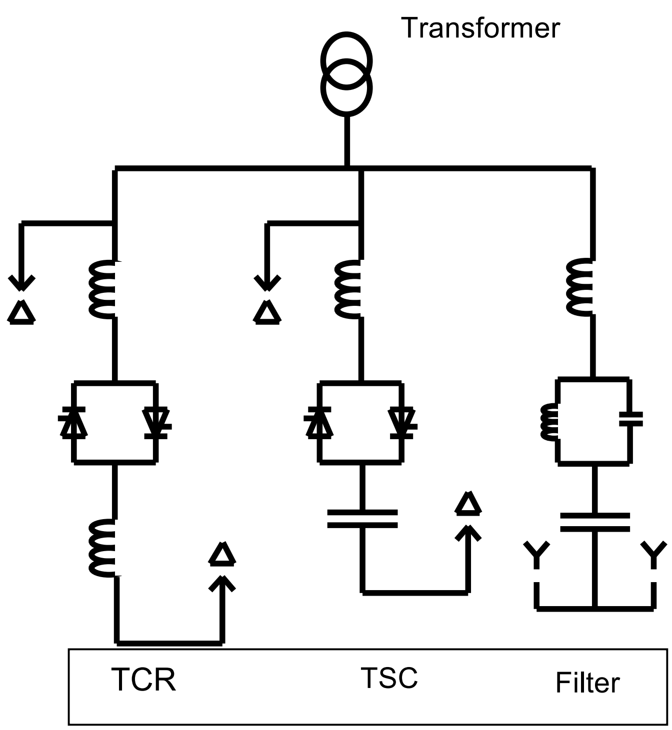
The power rating of a FACTS product can be tailored within practical limitations to the needs of the specific application. Although many of the principles involved in making a FACTS product have been known, power electronic switches with sufficient rating to be useful in transmission applications are relatively recent inventions. The largest rating that has been applied for FACTS products is for static var compensators where there are several installations with ratings above 300 MVA capacitive and 200 MVA inductive. By contrast, the largest installed rating for a unified power flow controller with two converters each rated at 160 MVA. These converters can generate either inductive or capacitive reactive power, which gives them a dynamic rating of 320 MVA. All FACTS products operate at voltage levels below 100 kV and are coupled to higher voltage networks through transformers. It is recognized that continued development of FACTS products with larger ratings is required for meeting the reactive power requirement in high voltage transmission networks.

Static Var Compensator (SVC)

The Static Var Compensator used for transmission system applications is a regulated source of leading or lagging reactive power. It is comprised of a combination of reactive branches connected in shunt to the transmission network through a step up transformer.

Thyristor control gives the SVC characteristics of a continuous voltage controller or of a stepped reactive power source depending on the control algorithms and the combinations of branches. There are three main building blocks available to make-up the required SVC capability. They are the thyristor-switched capacitor (TSC), the thyristor switched or thyristor controlled reactor (TSR or TCR), and the harmonic filter (HF). Figure 6-12 shows a configuration that has both inductive and capacitive capability.

Figure 6-12: Circuit diagram of a SVC containing a thyristor controlled reactor, a thyrister switched capacitor and a double tuned filter



A SVC is configured with the number of branches required to meet a utility specification. This specification includes required inductive compensation and required capacitive compensation. The sum of inductive and capacitive compensation is the dynamic range of the SVC. One or more thyristor-controlled reactors continuously vary reactive absorption to regulate voltage at the high voltage bus. This variation is accomplished by phase control of the thyristors, which results in the reactor current waveform containing harmonic components that vary with control phase angle. A filter branch containing a power capacitor and one or more tuning reactors or capacitors is included to absorb enough of the harmonic currents to meet harmonic specifications and provide capacitive compensation. The thyristor switched capacitor is switched on or off with precise timing to avoid transient inrush currents. If there is no requirement for precise voltage regulation, the inductive branch can also be controlled by synchronized thyristor switching to eliminate the need for harmonic filters.

The SVC can be part of an overall FACTS voltage control strategy including mechanically switched capacitors or reactors to provide bulk compensation for steady state conditions. For this strategy, control of switching the bulk compensation components can be done by the SVC control system or alternatively by the transmission system control. For high voltage transmission system applications, the SVC typically has a dynamic range of several hundred MVA to perform the required functions.

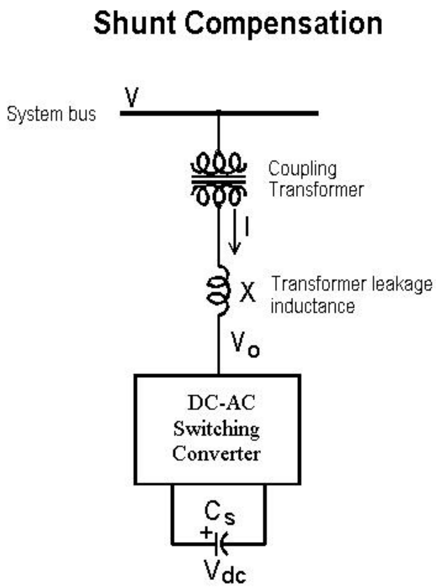
Static Synchronous Compensator (STATCOM)

The STATCOM performs the same voltage regulation and dynamic control functions as the SVC. However, its hardware configuration and principle of operation are different. It uses power electronic devices (gate turn-off thyristors (GTO) or insulated gate bi-polar transistors (IGBT)) that have capability to interrupt current flow in response to a gating command. This allows the switching pattern to generate or absorb controllable reactive power. The principle of generating reactive power with power electronic switching converters has long been recognized, but the practical implementation of these concepts for transmission line applications was not possible without suitable high-power electronic switches, having the inherent capability.

The STATCOM is analogous to an ideal electro-magnetic generator: it can produce a set of three alternating, almost sinusoidal voltages at the desired fundamental frequency with controllable magnitude. Unless it is equipped with either additional energy storage or a separate power source for the DC bus, the voltage angle is constrained to be very nearly in-phase with the transmission network at the point of connection of the coupling transformer. When this voltage is higher in magnitude than the system voltage, reactive current with a phase angle 90 degrees ahead of the voltage phase angle flows through the coupling transformer. This is analogous to the operation of a shunt capacitor. When the generated voltage is lower than system voltage, the current phase angle is 90 degrees behind the voltage phase angle that is analogous to the operation of a shunt reactor. The slight deviation in voltage phase angle absorbs power needed for the losses in the circuit. For high power applications a number of six or twelve pulse converters are operated in parallel to meet both the current rating requirement and the harmonic requirement of the network. Two different switching patterns, phase displaced converters with electronic devices switched once per cycle and pulse width modulation, have been used to form the sinusoidal waveform.

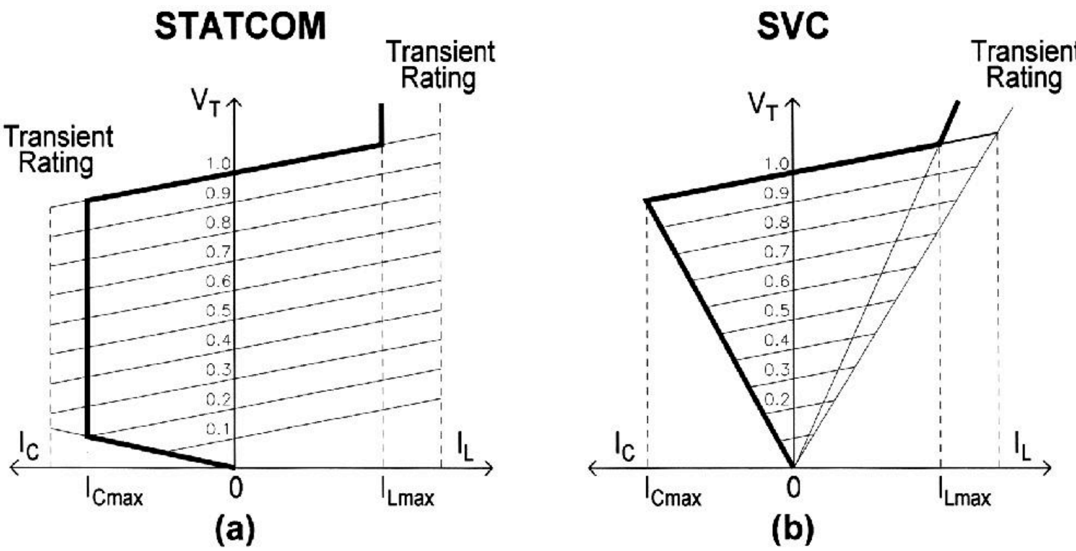
Figure 6-13 is a simple circuit diagram of a STATCOM. The switching converter circuit is controlled to generate current within the rating of the power devices. Since this current can be either capacitive or inductive, the dynamic range of a STATCOM is twice the KVA rating of the power circuit. For many applications it is not necessary to have the same magnitude of inductive and capacitive capability. These applications can often be most economically met by including either fixed capacitors or reactors in parallel with the STATCOM to shift the dynamic range. These capacitors can be configured as part of a filter circuit to allow switching patterns with higher harmonic content or they can be connected through mechanical breakers to extend the overall rating of the installation.

Figure 6-13: STATCOM circuit diagram



When comparisons between the capability of the SVC and STATCOM are made, they are often illustrated using a diagram of reactive current vs. system voltage. These diagrams are shown in Figure 6-14. The bold lines trace the normal operating points for these products. Whenever system voltage falls below the control setting, the SVC or STATCOM operates at the limit for inserting capacitive current. Since this limit is a control setting for the STATCOM and it is a current controlled device, the current is constant at lower voltages. If transient overload capability is included, that characteristic must also be part of the limiting function in the control. By contrast, the SVC is a capacitor in this region and the capacitive impedance controls its current. Along the top sloped line, both devices operate as voltage regulators. The slope of the line (droop) is an operator setting and is usually set between 0 and 0.1 pu. It is used to allow some variation in system voltage before the STATCOM or SVC moves to its limit so that other reactive power sources can be coordinated. The SVC or STATCOM control is faster than other products so without this coordination they would regulate system voltage until they reached the limit of their capability, then system voltage would change and other devices would act.

Figure 6-14: Characteristic Rating Curves for STATCOMs and SVCs

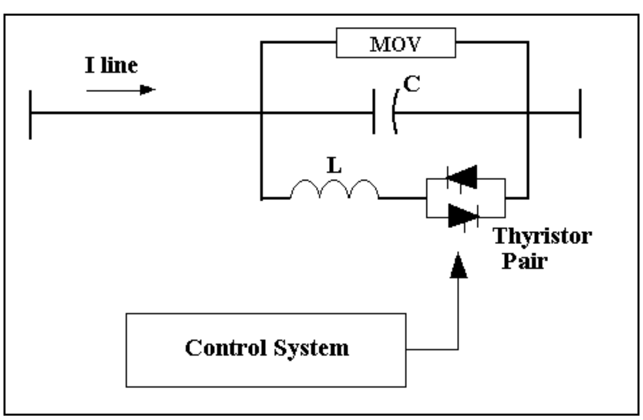


The control functions for STATCOMs and SVCs are similar. These are programmable digital controls and they can represent any function that is needed.

Thyristor Controlled Series Capacitor (TCSC)

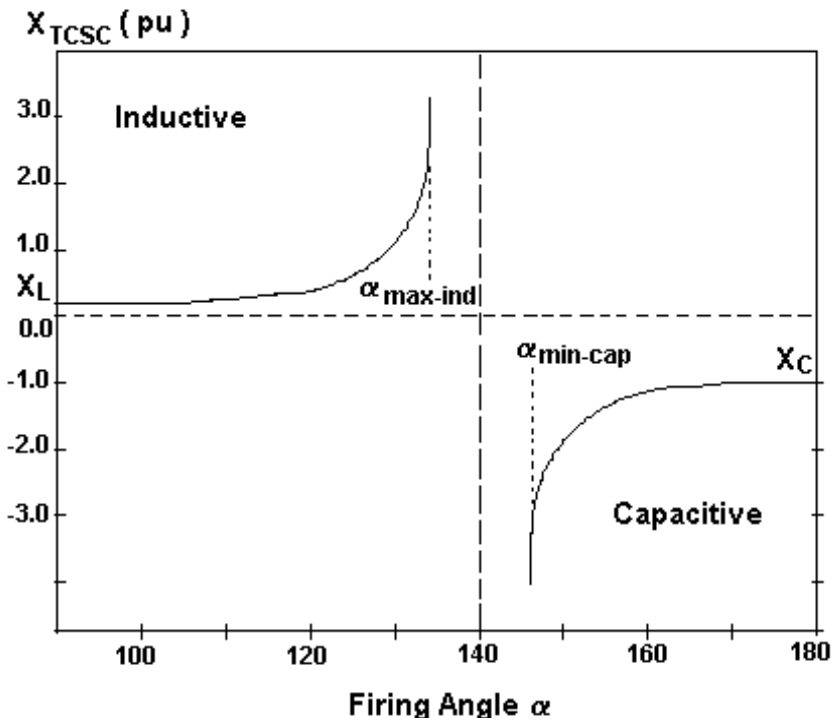
The TCSC is a capacitor in series with the transmission line, a thyristor pair and reactor (TCR) in parallel with the capacitor and a metal oxide varistor (MOV) to protect capacitor against overvoltage as illustrated in Figure 6-15. It can function as a series capacitor if the thyristors are blocked or as variable impedance when the duty cycle of the thyristors is varied. Applications currently in service provide impedance variation to damp inter-area system oscillations. The most economical installations often contain one segment of thyristor-controlled capacitors in series with one or more segments of conventionally switched series capacitors.

Figure 6-15: One-Line Diagram of TCSC



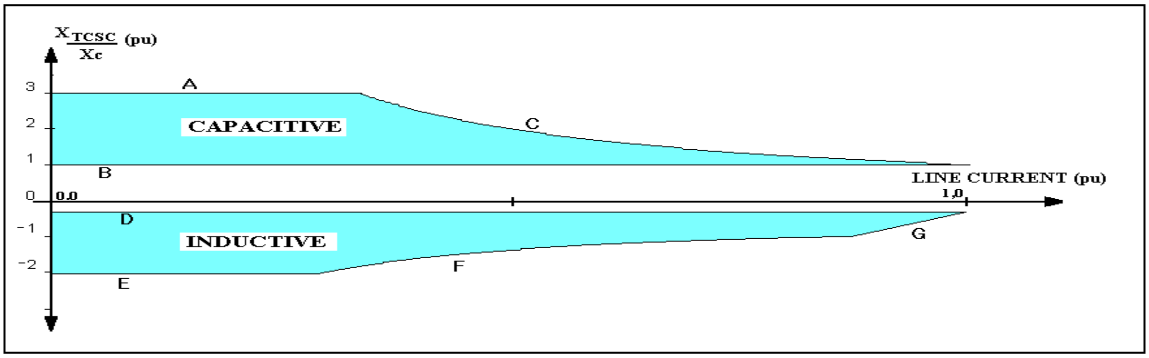
The TCSC steady state fundamental frequency impedance characteristic is shown in Figure 6-16 . The power circuit has three modes of operation: thyristors blocked (no gating and zero thyristor current), capacitor bypassed (continuous gating and full thyristor conduction), and operation with phase control of gate signal and consequent partial thyristor conduction, which is defined as “vernier” mode operation. In the vernier mode the firing angle can vary between 90° and α max-ind (inductive range) and between α min-cap and 180° (capacitive range). The angles α max-ind and α min-cap are established by design to prevent a fundamental frequency parallel resonance between the capacitor and the TCR.

Figure 6-16: TCSC Fundamental Frequency Impedance Characteristic



In fact, equipment ratings and characteristics dictate the limits of operation. Limits due to voltage and current ratings as well as control stability impose restrictions on the allowable reactance output control range. Figure 6-17 shows a typical reactance capability curve as a function of line current. It is important to note the reduction in the dynamic range as the line current increases. At low line current, the maximum reactance is limited to a fixed maximum value due to firing angle limitation (curve A). At higher line current, the maximum capacitor voltage rating dominates and the maximum reactance limit is inversely proportional to the line current (curve C). The minimum capacitive limit is obtained with the thyristors blocked (curve B).

Figure 6-17: Typical TCSC Impedance-Current Capability Characteristic.



At low line current, the maximum inductive reactance is restrained to a maximum (fixed) value due to firing angle limitation (curve E). At higher line current, the harmonic current heating effect dominates and the maximum reactance limit is inversely proportional to the line current (curve F). At very high line current, thyristor current may become limiting (curve G). The minimum inductive reactance is obtained with the thyristors in full conduction (curve D).

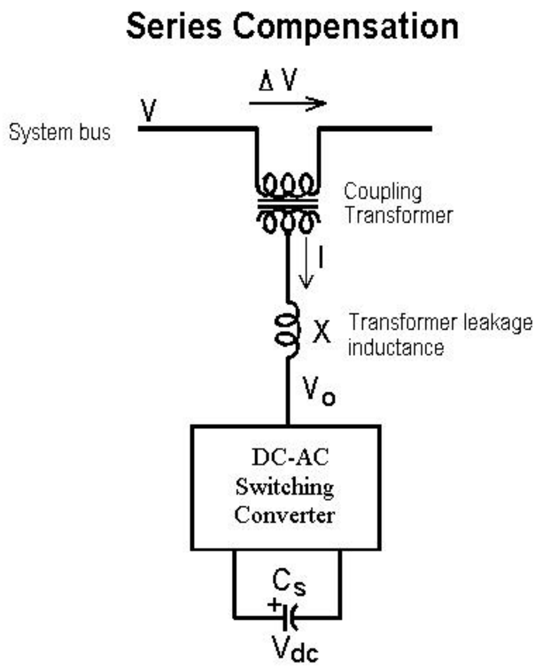
Naturally, the structure of the controller is dependent on the objective of the TCSC application. Allowing the fast control of the series reactance of the transmission line, the TCSC can be used basically for three purposes: power flow control, power swing damping and mitigation of subsynchronous resonance (SSR). The main difference among these three distinct applications is the control structure used and the rating of the equipment.

Static Synchronous Series Compensator (SSSC)

A static synchronous series compensator is a voltage source converter operated without an external electric energy source as a series compensator whose output voltage is in quadrature with, and controllable, independently of, the transmission line current. Its purpose is to increase or decrease the overall reactive voltage drop across the line and thereby control the transmitted electric power. The SSSC may include transiently rated energy storage or energy absorbing devices to enhance the dynamic behavior of the power system by additional temporary real power compensation, to increase or decrease momentarily, the overall real (resistive) voltage drop across the line.

The SSSC whose circuit is shown in Figure 6-18 is often equated with a series capacitor, but it has several operational differences. In contrast to a series capacitor the SSSC is an AC voltage source. Without energy storage at the DC bus it is constrained to produce fundamental frequency voltage that has is phased either 90 degrees ahead or 90 degrees behind the transmission current. This has the same effect in the transmission line as adding either a series capacitor or a series reactor. As long as there is sufficient line current to supply internal losses in the SSSC and maintain DC bus voltage, the AC voltage inserted in series with the line is independent of the line current. This differs from the characteristic of simple series impedance and allows larger variation of the apparent line impedance. The greatest effect occurs at lower magnitude line currents.

Figure 6-18: Circuit diagram for a Static Synchronous Series Compensator



When the SSSC operates with fixed control inputs the inserted voltage has the fundamental output frequency. Thus the effective output impedance versus frequency characteristic of the SSSC is unable to form the classical series resonant circuit with the inductive line impedance to initiate subsynchronous system oscillations. On the other hand, the SSSC has a very fast response and, with proper control, it can be very effective in damping system oscillations at frequencies as high as those that cause subsynchronous resonance concerns.

As with any series connected product, the rating of the SSSC must be carefully selected to assure that it does not limit the overall capability of the transmission circuit. Electronic circuits have less inherent transient overload capability than passive electric circuits so the current rating of the SSSC must match the overload current rating of the transmission line to prevent bypassing the SSSC during system swings. Protection of the SSSC is accomplished using a combination of an electronic bypass and a mechanical breaker. The electronic bypass may be a switching algorithm for the GTO or IGBT devices in the converter or, for higher current circuits, it may be a separate thyristor switch with a high temporary current rating. The bypass protection is uses instantaneous line current as its control variable and it can be programmed to allow reinsertion attempts to return the SSSC to service as rapidly as possible.

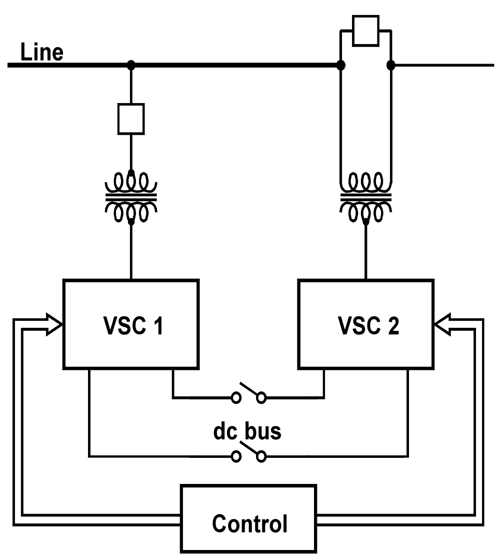
The DC bus for the SSSC can be enhanced by addition of temporary energy storage using additional DC capacitors, batteries or other energy storage devices. This would provide ability to transiently inject or absorb real power from the transmission line to enhance its ability to damp system oscillations. To date there have not been applications using this capability and detailed studies that define both system conditions requiring the enhancement and appropriate control algorithms are required to define this benefit.

Unified Power Flow Controller (UPFC)

The Unified Power Flow Controller (UPFC) provides voltage, and power flow control by using two high power voltage source converters (VSC) coupled via a DC capacitor link. Figure 6-19 shows the two interconnected converters. VSC 1 is connected like a STATCOM and VCS 2 is connected as a SSSC in series with the line. With the DC bus link closed, the UPFC can simultaneously control both real and reactive power flow in the transmission line by injecting voltage in any phase angle with respect to the bus voltage with the series converter. The shunt-connected converter supplies real power required by the series connected converter. With its remaining capacity the shunt converter can regulate bus voltage.

The UPFC's functional flexibility meets the specification of a "black box" that American Electric Power (AEP) defined for the Inez load area in eastern Kentucky. [24]... The location of the UPFC is AEP's substation in Inez, Kentucky. Planning studies showed that together with a high capacity 138 kV transmission circuit, the UPFC, with ratings of 160 MVA for the shunt inverter and 160 MVA for the series inverter, could deliver as much as 900 MW of real power to the Inez area during emergency conditions. A control algorithm that includes operation of six mechanically switched capacitor banks and two series reactors maintains power flow and voltage regulation for a wide range of system conditions with minimum transmission system loss. This installation was developed and placed into operation in 1997 by AEP, EPRI and Westinghouse as part of EPRI's FACTS development program.

Figure 6-19: Circuit Diagram of a Unified Power Flow Controller



The UPFC circuit can be reconfigured by use of external switches and possibly additional transformers to form STATCOM, SSSC, or coupled SSSC circuits. This latter circuit is called the interline power flow controller IPFC.

6.4 COMPARISON OF TECHNOLOGIES

Comparison Of LCC and VSC HVDC

Table 6.2 provides a high level comparison between the features of LCC and VSC HVDC transmission.

Table 6-2: Comparison of LCC and VSC HVDC

Comparison	LCC	VSC
Semi-Conductor Device	Thyristor – Unidirectional current. No controlled turn- off capability. Currently available 6 inch, 8.5 kV and 6000 A.	IGBT – Bidirectional current with anti-parallel diode. Controlled turn-off capability. Currently available 1800A turn off current capability.
DC overhead transmission	Up to +/- 800 kV	Up to +/- 640 kV (expected shortly)
DC cable transmission	Mass impregnated cables up to 500kV.	Polymer insulated cables up to 300kV currently type tested. Can be used with mass impregnated cables for higher voltages.
DC power	Currently up to 6000 MW per bipolar system.	Currently up to 1100 MW per bipolar system and expected to increase to 2200 MW.
Real & reactive power control	Always consumes reactive power. Reactive consumption varies with power and is not independently controllable. Reactive power consumption is up to 60% of real power rating.	Real & reactive power is controlled independently. Full range of reactive power can be generated or consumed independent of the real power.
Converter Losses (load plus no load)	In range of 0.08% of terminal rating	In range of 1.4% of terminal rating
Power Reversal	Reverse polarity of DC voltage	Reverse direction of DC current
Minimum power operation	Minimum power levels typically in the range of 5% to 10%	No minimum power, can operate smoothly down to zero power
Transformer requirement	HVDC converter transformer	Ordinary power transformer
AC filter requirements	Large filter banks required which can be used to supply reactive power to the converter. Typically filters must be switched as DC power transfer changes.	Reduced AC filter requirements due to concentration of harmonics into a narrow band by the PWM switching algorithms used. Filters are not switched.

Power Quality	Typically AC filters and shunt capacitors used for reactive power supply must be switched as DC power transfer changes resulting in step changes in AC system voltage.	Filters are not switched. The VSC can provide smooth control of the AC bus voltage.
AC system short circuit level (ESCR)	Critical in design, lower ESCR results in degraded performance.	No impact on design.
Black start	Very limited application	Capable of black start and feeding passive loads.
Commutation failure performance	Fails commutation for AC disturbances, more prominent as ESCR decreases	Does not fail commutation
Over load capability	Available if designed for up to any required design value	Does not have any overload capability
DC fault	DC fault cleared by converter control with fast automatic restart. No AC current feeds fault.	DC fault cleared by use of DC breaker and trip of AC breaker, followed by automatic restart. AC fault current flows into fault and reactive power drawn from AC system until fault cleared.
Application of small taps	Adversely affects the performance of the main HVDC terminals, not likely to be used.	Will not adversely affect main HVDC terminals, has potential applications.
Temporary overvoltages	Potentially large due to amount of reactive compensation required	Reduced size of filters and ability to control reactive power independently from real power provides control of overvoltages.

Technical Comparison of HVDC and HVAC Technologies

When performing a technical comparison HVDC and HVAC transmission technologies, the following factors should be considered:

Asynchronous Connection

Due to the asynchronous nature of islanded power systems, connection using AC lines may not be possible without expensive upgrades to bring the two systems into synchronism. With dc, the systems can remain asynchronous.

Limitation of Short Circuit Power

As reactive power cannot be transmitted over a DC line, the transfer of one systems short circuit power to another is nonexistent. This is important as it means that AC breakers and buswork in the connected substations will not have to be upgraded to accommodate the new power (other than for steady state requirements). If the same connection is made via an AC connection, many AC system components may need to be upgraded.

Power Control

Due to the inherent controllability of DC, the powerflow can be scheduled and controlled very precisely. Electromechanical oscillations in one system do not influence the transmission of energy and have no effect on the second AC system. Energy flow can be stopped quickly or reversed.

AC Voltage Control

A VSC HVDC system can provide AC voltage control in a similar fashion to a static var compensator or STATCOM in the AC system. The ability of the VSC to provide AC voltage control is independent of the real power transfer of the HVDC link and is possible even with the HVDC line or cable disconnected with each terminal effectively operating as a STATCOM.

Enhancement of Stability

The fast and precise control of the powerflow in an HVDC line can also be used to create positive damping of electromechanical oscillations by modulation of the transmitted power. In the event of a large disturbance, the DC power can be stepped from 1pu power to 0 in a matter of cycles to assist in system recovery. The HVDC link can effectively be used to improve the stability of the interconnected AC systems or of a parallel AC connection.

Other Regulating Functions

The fast and precise control of the powerflow in an HVDC line can also be used to provide other regulating functions to the interconnected systems such as frequency regulation, frequency keeping, sharing of spinning reserve, etc.

Loop flows can be avoided.

Grid Restoration Capability

VSC HVDC transmission provides a means to control voltage and stabilize frequency during grid restoration. Frequency control is not limited in the same way as a conventional power plant, and full black start capability is possible.

Application to Wind Power Generation

Connection of large amounts of wind power to networks using VSC technology is possible without the need to provide a high short circuit level.

Use of VSC technology allows the connection of wind generation at weak points of the system without the need to provide additional compensation.

Terminal Stations

Traditionally HVDC terminal stations have been substantially larger in footprint, more costly and more complicated that AC terminal stations. As many of the new FACTS devices required to support AC transmission are based on technology similar to that of HVDC terminal stations this difference is expected to become less pronounced.

Reliability

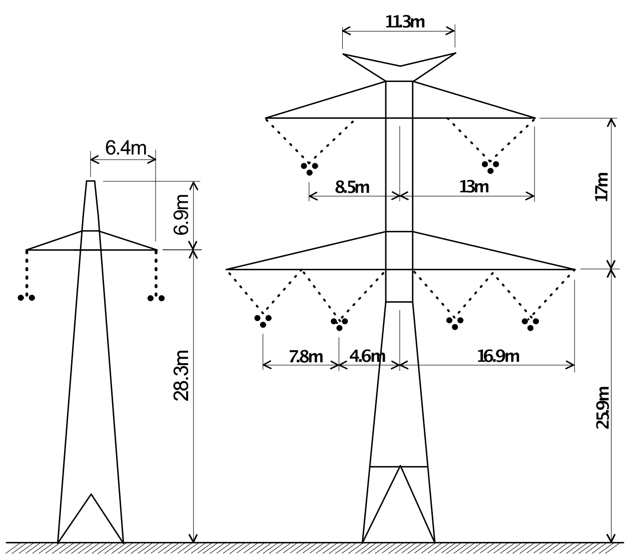
A bipolar HVDC line can be considered to have comparable reliability to a double circuit, single tower AC line. This assumes that the HVDC system can operate monopolar with electrode return. If continuous electrode return is not possible then loss of one of the pole conductors in the HVDC line will result in the need to shut down the entire HVDC link.

With a greater dependence on FACTS devices, the overall reliability of the AC transmission systems is becoming more dependant on the reliability of the FACTS devices themselves which are based on many of the same technologies as HVDC terminal stations. Therefore when comparing the overall reliability of the transmission alternatives it is necessary to consider the line and required terminal stations.

Tower Size

Figure 4-1represents a comparison between a typical +/- 500 kV HVDC bipolar line tower for 3000 MW (on the left) and the equivalent double circuit 500 kV AC line tower (on the right) for the same power level.

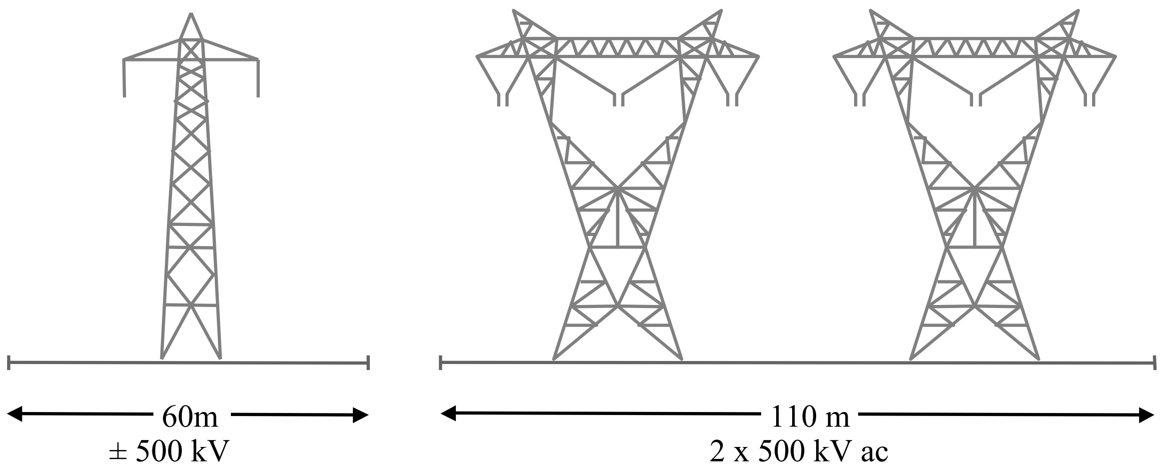
Figure 6-20: HVDC and HVAC Tower Configuration



Line Right of Way

Other than the large footprint required by the converter station, the transmission right of way for comparable amounts of power transmitted via AC or DC is much less for DC giving a smaller overall footprint as shown in Figure 4-2.

Figure 6-21: AC vs DC Comparison Right of Way



Losses

Losses in an HVDC transmission system are typically lower than in a comparably rated HVAC transmission.

Ability to Tap Along Transmission Line

In the past, tapping into an HVDC system was more difficult than in the case of AC transmission, particularly if the size of the tap was small compared to the overall transmission rating and the AC system at the tap location was weak. With the development of VSC technology, the application of small taps to an HVDC transmission line is much more attractive.

Electric and Magnetic fields

The recent awareness of the public of the potential risk of electrical and magnetic fields is a concern that may cause a project to be delayed. Whether this concern is justified or not, the direct fields of an HVDC line are less critical than the alternating fields of an AC line.

Cable Issues

AC cables are limited in length to about 40 miles at 500 kV. This is due to the AC capacitive effects of the cable. When utilizing dc, these effects are not a factor enabling transmission of power over long cable distances.

Harmonics

LCC HVDC produces substantial harmonics and requires complex filtering. Potential harmonic interactions with the AC system has traditionally been a disadvantage associated with the application of HVDC. With the development of VSC HVDC this concern has been addressed.

Commutation Failures

Susceptibility of LCC HVDC to commutation failures which is aggravated by reduced AC system strength and the need to provide synchronous compensators is also a disadvantage of LCC HVDC. Voltage source converters due not suffer commutation failures similar to line commutated converters and operation of VSC HVDC is not dependant on AC system strength.

Reactive Power Requirements

The need to provide adequate reactive power to support an LCC HVDC terminal has been a disadvantage of LCC HVDC. Potential overvoltages associated with the AC filters and shunt capacitors which provide the reactive compensation has in some instances required the application of additional fast acting dynamic compensation devices. VCS HVDC solves this problem. In addition the VSC HVDC provides fast AC voltage control.

6.5. APPLICATIONS OF HVDC TRANSMISSION

Appendix 1 contains a listing of current HVDC projects worldwide. When considering potential applications of HVDC transmission it is necessary to define some of the basic factors driving transmission system expansion. These include:

- Bulk power transfer across long distances
- Cable transmission.
- Improved utilization of existing infrastructure
- Interconnection of asynchronous systems
- Integration of remote energy resources
- Infeed to congested load areas
- Supply of isolated loads

Bulk power transfer across long distances

Bulk power transfer across long distances is an ideal application for HVDC transmission. This has traditionally been one of the most common applications of HVDC, providing a cost effective and reliable alternative. Schemes rated at 3000MW with transmission distances of 1500km are currently in operation, and with the development of UHVDC schemes rated at over 6000MW, with transmission distances over 2700km are in the execution phase.

Cable Transmission

The need for long distance cable transmission is an ideal application of HVDC transmission and has also been a typical application for HVDC in the past. Systems rated at 450kV with cable length of 580km are currently in operation.

The development of VSC HVDC technology has provided additional benefits related to cable systems, in particular the ability to use cost effective, polymer insulated cables. The “packaging” of VSC converters and polymer insulated cables has provided a cost effective solution for cable installations where length of the cable transmission is not the primary factor. VSC HVDC with polymer insulated cables can be used as an alternative to overhead transmission lines, addressing some of the environmental issues associated with the overhead lines.

Improved utilization of existing infrastructure

The ability of HVDC to stabilize interconnected systems due to its fast controllability can allow a better utilization of existing infrastructure. For instance, HVDC lines which are placed in parallel to AC lines can allow for increased power transfers on the AC lines with the implementation of HVDC modulating functions to stabilize the AC network. Modulating control functions such as power swing damping, frequency limits, frequency control, HVDC power run ups and run backs can all result in improved stability of the interconnected AC systems and better utilization of existing infrastructure.

VSC HVDC has the added benefit of providing AC voltage control independent of real power flow. In addition, VSC HVDC can provide voltage and frequency control which can be beneficial in grid restoration situations.

The addition of an HVDC system will not directly increase short circuit levels alleviating the need to replace AC breakers with system expansion.

Interconnection of asynchronous systems

HVDC offers the only cost effective solution for interconnecting two asynchronous systems and has been used extensively for this purpose in the past. Back-to-back HVDC links offer a means of interconnection which is independent of the frequency and phase angle between the two asynchronous systems.

Interconnection of asynchronous systems also applies to the connection of islanded systems to the main grid. Often these island are located at a distance which does not allow for AC cable interconnection, and therefore HVDC transmission offers the only means of interconnection.

Integration of remote energy resources

Integration of remote energy resources using HVDC in the past has been mainly in instances of large scale generation development located a long distance from the load centers. Traditionally the generation has been hydro or thermal based. With the increased development of renewable generation resources, and in particular wind generation which must be geographically dispersed there will be a need to provide a means of integrating this power to the existing network which may be remote from the generation site.

Off shore wind farms offer an example of this requirement and VSC HVDC offers an excellent solution.

Infeed to congested load areas

The need increase power transfers into congested load centers along with the inability to obtain new transmission line right of ways provides an opportunity for the expanded application of HVDC. A number of systems have been built using HVDC cables to provide a means of meeting this need. Both LCC and VSC HVDC has been used in such applications.

Supply of isolated loads

VSC HVDC provides a suitable means for supplying isolated loads form the main grid. A present example would be the supply of off-shore platforms.

6.6 POTENTIAL APPLICATION OF HVDC TO CANADIAN NATIONAL ELECTRICAL GRID

A Canadian National electrical grid would have to span across a number of asynchronous systems which would need to be implemented using HVDC interconnections. The potential application of HVDC would depend on how the grid were developed. If the grid were to be developed isolated from the existing AC networks then HVDC could be used as a means of bulk power transfer between the existing systems. If the grid were to be developed integrated with the existing AC networks, then HVDC back-to-back systems could be used as a means of implementing the interconnections and the underlying AC networks would serve to move the power within their own systems. In all likelihood, a Canadian National grid would probably be developed as a blend of the two options.

A number of existing HVDC links within the asynchronous networks can provide a good indication of the expected performance and reliability. Currently HVDC systems exist within Manitoba, within British Columbia, between the Alberta and Saskatchewan systems, between the Quebec and New England systems, and between the Quebec and New Brunswick systems. A link between the Quebec and Ontario systems is in the execution stage. Additional links currently under consideration include a multi-terminal connection between Labrador, Newfoundland and the Maritime provinces, a multi-terminal connection between the provinces of Alberta, Saskatchewan and Manitoba, and a connection from the Alberta system to the United States. AN HVDC link between Manitoba and Ontario has also been considered in the past.

The discussion below attempts to identify some of the issues related to a Canadian National grid and the application of HVDC transmission to address those issues.

Bulk Power Transfer

As a result of the distances involved, HVDC transmission would provide a suitable means for bulk power transfer over long distances either within a given AC system or between asynchronous AC systems. The HVDC systems would most likely be bipolar transmission systems in order to provide the necessary reliability. Current technology would require the use of LCC HVDC to achieve ratings in the range of 2000 to 3000MW, however VSC technology is increasing in rating.

Interconnection of Asynchronous Systems

A Canadian National electrical grid would have to span across a number of asynchronous systems which would need to be implemented using HVDC interconnections. Either long distance or back-to-back connections could be used.

AC System Strength Issues

In cases where LCC HVDC were used, the AC systems would need to be sufficiently strong to support the HVDC interconnection. With a desired minimum ESCR of 2.5, a typical reactive power compensation requirement of 60% for the HVDC terminal, a 3000MW HVDC link would require the AC system short circuit MVA level to be at least 9300MVA.

Where AC system strength were not sufficient, the additional of synchronous compensators would most likely be required

If VSC HVDC were used, then AC system strength would not be an issue.

HVDC Multi-Infeed Issues

If new HVDC systems were introduced in close proximity to each other or in close proximity to existing HVDC systems, multi-infeed issues would need to be addressed.

Multi-Terminal HVDC

Multi-terminal HVDC could be an attractive option for portions of a Canadian National grid. VSC technology provides a promising way of tap into an HVDC link.

Canadian Academy of Engineering

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