GUIDE

Water Conservation, Efficiency, and Productivity Plan –

Electric Power Generation

August 2012

DRAFT

Acknowledgements

Industry members associated with this document support the important principles of the Alberta *Water for Life* strategy to address current and future water scarcity and its potential limitation on benefits derived from various forms of water use.

Preparation of this document was led by the following industry working group:

Jim Hackett	ATCO Group, Utilities
Ahmed Idriss	Capital Power Corporation
Rod Kause	TransAlta Corporation
Kelly Scott	ATCO Power (chair)
Joan Tingley	ATCO Power

The working group acknowledges the efforts of previous representatives who helped to initiate this plan, including James Guthrie and Ken Omotani.

The report was compiled in part by Golder Associates Ltd, with support from Gary Blechinger of GeoWa. Information sources include the Alberta Electric System Operator (AESO), Alberta Energy Resources Conservation Board (ERCB) and Alberta Environment and Sustainable Development (AESRD). All information used in this report is available in the public domain.

Disclaimer

This publication was prepared by ATCO Power, Capital Power Corporation, and TransAlta with the assistance of Golder Associates Ltd. The electricity generating companies represent a significant portion of the power generation capacity in Alberta, but do not represent all of the power generation sector. Therefore, the information and views expressed by this document may not represent the views of other Alberta power companies that are not listed.

The information in this document represents the best available information at the time this document was produced in May 2012. While it is believed that the information contained herein is reliable, ATCO Power, Capital Power Corporation, TransAlta, and Golder Associates do not guarantee its accuracy. The use of this report or any information contained will be at the discretion and risk of the user.

Executive Summary

This report presents a Conservation, Efficiency and Productivity (CEP) plan for the Alberta electric power generation sector. The plan is founded in the goals and objectives of CEP plans as outlined in the Alberta Water for Life Strategy, and the recommendations developed by the Alberta Water Council.

This Electric Power Generation Sector CEP Plan is intended to provide an initial road map for industry to document existing water use, expected future water use, and opportunities to further improve water use, as envisioned by Alberta's *Water for Life* strategy.

The sector has a long history of careful management of water use, implementing new technologies and operating practices when appropriate. The sector will continue to investigate technologies to improve environmental performance, including water use and will continue its collective commitment to meet regulatory water use requirements.

As part of the CEP Plan development, the sector produced a metric that can be used to estimate sector water consumption. The selected performance measure is water productivity, defined as the volume of water consumption (i.e. water diversion minus return flow) per unit of energy production. Based on this metric the Plan reached the following conclusions with respect to a baseline period of 2000 through 2002:

- Estimate a 31% water productivity improvement by 2015; 50% by 2029
- Water consumption is currently expected to stay about the same until 2030, despite a forecast doubling of electricity demand
    - 2% increase in total water consumption by 2015, 8% by 2029

Future water requirements for electricity generation will be influenced by proposed air emissions regulations and other environmental initiatives; legislation to achieve one environmental objective may impact another objective (e.g. air emission controls may increase water consumption). Improved water use will be aided by balanced assessments between competing air, water and land environmental objectives – by evaluating tradeoffs as part of the planning process for new power generation

As a final note, actual water data was difficult to find or unavailable and improving the availability and completeness of water diversion, consumption and return flow information available from AESRD for all sources/sectors will improve the ability to estimate and forecast actual water consumption and use.

Contents

Figures

Tables

Site Pictures

Appendices

1 Overview of the Conservation, Efficiency, and Productivity (CEP) Sector Plan

This report presents a Conservation, Efficiency and Productivity (CEP) plan for the Alberta power generation sector. The plan is founded in the goals and objectives of CEP plans as outlined in the Alberta Water for Life Strategy, and the recommendations developed by the Alberta Water Council.

1.1 Goals and Objectives of the CEP Sector Plan

Water for Life

Water for Life: Alberta's Strategy for Sustainability (Alberta Environment, 2003a) is based on the principle of Albertans becoming leaders at effective and efficient use of water.

The *Water for Life* strategy includes three specific goals:

- Safe, secure drinking water supply;
- Healthy aquatic ecosystems; and
- Reliable, quality water supplies for a sustainable economy.

These goals will be met through:

- Knowledge and research;
- Partnerships; and
- Water conservation.

Alberta Water Council Recommendations

The Alberta Water Council (AWC), as part of Alberta's *Water for Life* strategy, recommended the development of publicly available water CEP plans for seven major water-using sectors: chemical and petrochemical, irrigation, forestry, mining and oil sands, urban municipalities, oil and gas, and power generation.

The AWC expects that sector CEP plans will promote management practices to conserve water, in part by using water more efficiently and productively than before the development of *Water for Life* strategy. Accordingly, the CEP plan should promote the use of less water to achieve similar economic productivity. The focus of the CEP plan is on water quantity; although water quality is also important, it is outside the scope of this plan.

The purpose of this document is to provide information related to the power generation sector CEP Plan (Plan) for conservation, efficiency and productivity. The AWC (2006) defines these parameters as follows:

- **Conservation** refers to any beneficial reduction in water use, loss or waste, or practices that improve the use of water to benefit people or the environment;
- **Efficiency** refers to the accomplishment of a function, task, process or result with the minimal amount of water feasible. Efficiency is an indicator of the relationship between the amount of water required for a particular purpose and the quantity of water used or diverted; and

- **Productivity** refers to the amount of water required to produce a unit of any good, service, or societal value.

Conservation, Efficiency, and Productivity Goals

A specific outcome of the *Water for Life* strategy relating to water conservation is: "*Demonstration in all sectors of best management practices, ensuring overall efficiency and productivity of water use in Alberta improves by 30% from 2005 levels by 2015. This will occur when either demand for water is reduced or water use efficiency and productivity are increased*." (Alberta Environment, 2008b).

The 30% target applies to the aggregate of all water users in Alberta and was not intended to be an absolute target for each sector. The Plan was developed with the overall provincial target in mind.

Future Vision

The future vision of the CEP plan is to provide an initial road map for industry to document existing water use, expected future water use, and opportunities to further improve water use for the purpose of pursuing Alberta's *Water for Life* strategy.

In the future, the power generation sector anticipates continuing to balancing cost-effective economic uses with environmental and social values. Industry will continue to investigate technologies to improve environmental performance, including water use. At the same time, the sector will continue its collective commitment to meet regulatory water use requirements.

1.2 Scope of Plan

This Plan was prepared by a sub-set of companies representing a significant portion of the power generation capacity in Alberta. The power generation industry, through the corporate commitment of the participating operators, is committed to responsible water use and the participants are acting as voluntary sector representatives given the absence of an over-arching industry organization.

Overall, this Plan addresses the AWC's recommendations by:

- Providing factual information regarding historical water use and current projections for future water use;
- Demonstrating industry practices and voluntary actions to improve water management;
- Identifying practical opportunities for future water use efficiencies;
- Identifying potential measures that may further contribute to Alberta's goal of a 30% improvement in overall water efficiency and productivity from 2005 levels by 2015; and
- Identifying future challenges facing the electric power generation sector.

The Plan supports the *Water for Life* strategy by documenting historical and planned improvements. In Alberta, electricity (or power) is generated in facilities using a variety of 'fuels' such as coal, natural gas, wind, and water. Historically, the majority of power generation capacity in Alberta was based on burning fossil fuels (coal, with an increasing importance of natural gas). As a sector, there is an increasing focus on the use of renewable energy sources, such as wind and water.

Water is an extremely important resource for most electricity production technologies and this Plan estimates water use from 2000 through 2029 by the following power generation types:

- Coal;
- Natural Gas (Simple Cycle, Combined Cycle and Co-generation);
- Biomass;
- Wind; and
- Hydroelectric.

The Plan focuses on the volume of water consumed for power generation requirements and not other industrial purposes. Water consumption is defined as the difference between the amount of water diverted from a water body and the amount of water returned to the water body (i.e. return flow). Any water that is not returned to the water body is counted as 'water consumption', including evaporation to the atmosphere.

The Plan excludes water diverted for the two purposes below. This was necessary to avoid double-counting water use by other industry sectors, where power generation facilities operate as an integral part of the industrial processes. In these cases the approvals associated with the water use are held by the other industries and not the electric power sector.

1. Resource (fuel) extraction and delivery, such as coal mining and natural gas production.
2. Concurrent uses, such as the use of surplus heat from electric power generation to create steam for other industries including the upstream oil and gas sector.

As a measure of productivity, the CEP plan compares water used for power generation purposes to power generation in terms of net megawatt-hours (MWh), or the electric power delivered to the Alberta electric system. The power production values include all power generation within the province of Alberta, except for power imported from adjacent jurisdictions (i.e. B.C. or Saskatchewan).

All information used to prepare this plan is publicly available. Key data sources are listed below:

- Alberta Electrical System Operator (AESO) annual market statistics (AESO, 2011);
- Generation data from AESO Annual Net Generation Data (2000–2011 power generation) (AESO, 2011);
- Forecast power generation assumptions from AESO *Future Demand and Energy Outlook* (2009 -2029) for forecasted information (2012 to 2029)(AESO, 2009a);
- Alberta's Energy Reserves 2010 and Supply/Demand Outlook 2011-2020 (ERCB, 2011);
- Water use and license data for AESO identified units from 2000–2011 available through Alberta Environment and Sustainable Resource Development (AESRD); and
- Assumed typical industry water productivity rates published by the Energy Technology Innovation Policy Research Group (2010).

1.3 The Case for Water CEP

Benefits

Water CEP initiatives offer many potential benefits. From the industry perspective, lower water usage may be associated with cost savings as a result of reduced treatment, infrastructure or pumping costs, but it also aligns with the industry culture to use resources wisely and minimize environmental impacts. For the Alberta public, water CEP initiatives help to promote the valued use of water for a variety of purposes.

The CEP plan may help to provide a variety of benefits:

- Potential industry water savings and corresponding net economic benefits for producers by avoiding water costs, depending on the required additional infrastructure capital, operating and maintenance costs;
- Heightens awareness and may help to identify new opportunities for continuous improvement;
- Opportunity to collaborate as good environmental stewards of provincial water resources;
- Opportunity to share factual information with the public; and
- Potential improved information basis for regional watershed management and water allocation.

Risks

The risks associated with not continuing to improve industry water conservation, efficiency, and productivity includes:

- Uneconomic use of water (i.e. higher operating costs, inadequate water availability); and
- Loss of economic and environmental opportunities for both the sector and the Province.

Affected Parties

External parties that could potentially benefit from this CEP plan ultimately comprise the province, residents and industry of Alberta, with the direct benefit being the economic success of companies demonstrating sustainable and prudent water management. Specific external parties include:

- The Government of Alberta;
- AWC;
- Watershed Planning and Advisory Councils (WPACs) and their membership;
- First Nations and Métis populations;
- Urban and rural municipalities whose drinking water sources are in watersheds where industry is located;
- Rural water users, such as agriculture; and
- Other commercial and industrial water users.

2 Profile of Existing Water Systems

2.1 Power Generation in Alberta

Overview

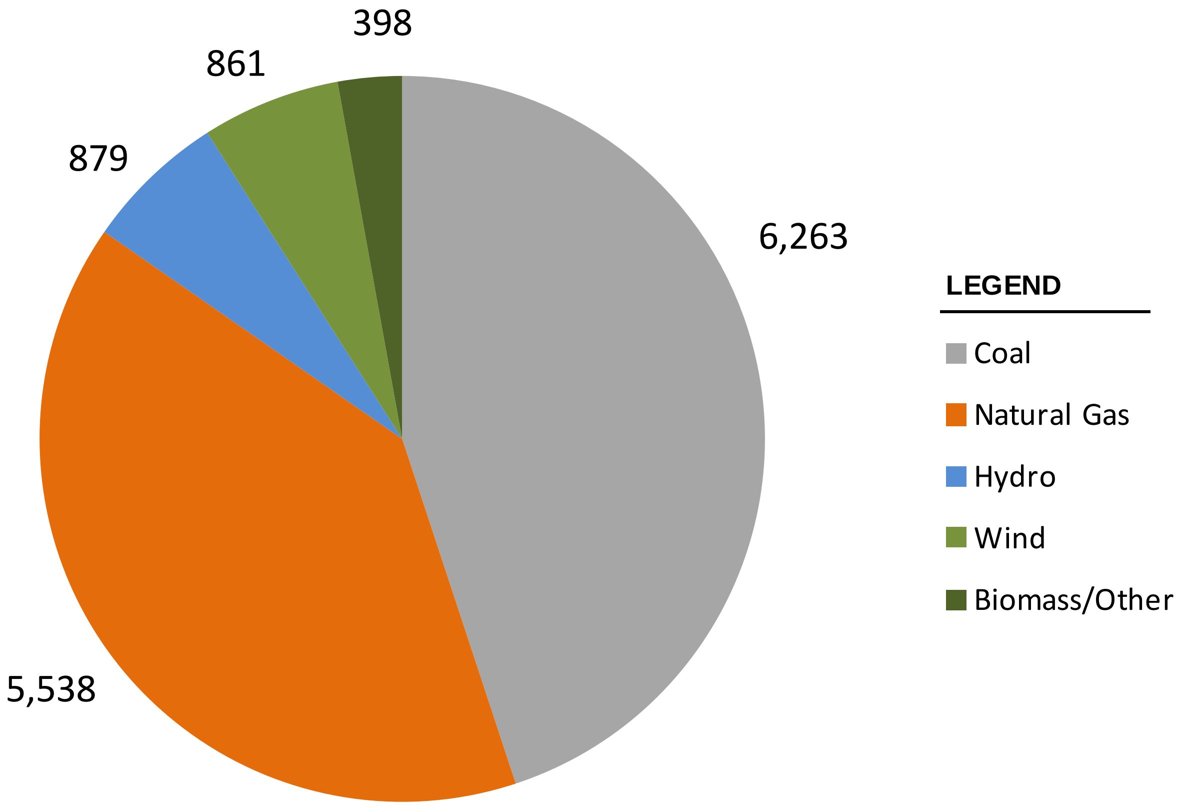
Alberta's diverse mix of power generation has developed over the last century since the province's first large-scale hydroelectric power plant was built in 1911 (AESO, 2009b). As of 2011, the total installed generating capacity in Alberta was about 13,500 megawatts (MW). The Alberta Electric System Operator (AESO) estimates that an additional 11,500 MW of electricity capacity will be required by 2027 to meet Alberta's growing energy needs (AESO, 2009b).

Capacity (MW) is the amount of electricity that might be produced, while generation (MWh) is the rate at which electric power is generated and consumed. For example, an electric generator capable of producing 100 MW (capacity) and operating at 50% output will produce 50 MWh (generation) of electricity in one hour. The capacity of a power facility is related to generation by a capacity factor. A capacity factor is the relative utilization of a power generation facility as a percentage of the generation capacity. Capacity factors vary greatly depending on the generation type (see Appendix A for various typical capacity factors for different generation types).

The diverse makeup of Alberta's existing generating capacity in 2011 is shown on Figure 1. Fossil-fueled sources account for the majority of Alberta's installed generating capacity, with coal–fired plants making up about 45% of the total generating capacity and natural gas accounting for about 40%, including co-generation at industrial operations. The remainder is hydro, wind, and biomass (energy produced from organic sources such as wood waste, garbage, or animal matter).

Power generation capacity is located throughout the province. Figure 2 shows the location of generating capacity (MW) by watersheds, based on the most recent information published by the AESO (2011). Coal generation capacity is largely situated near Edmonton in the North Saskatchewan River basin (Sundance, Keephills and Genesee power plants with a total installed capacity of 4,330 MW). Generation using natural gas occurs across Alberta with many facilities located in northern Alberta, where many industry power users utilize waste heat created in the electricity production process to generate steam heat for industrial processes. The majority of generation capacity using renewable fuels, such as wind and water for hydroelectricity, are currently installed in southern Alberta.

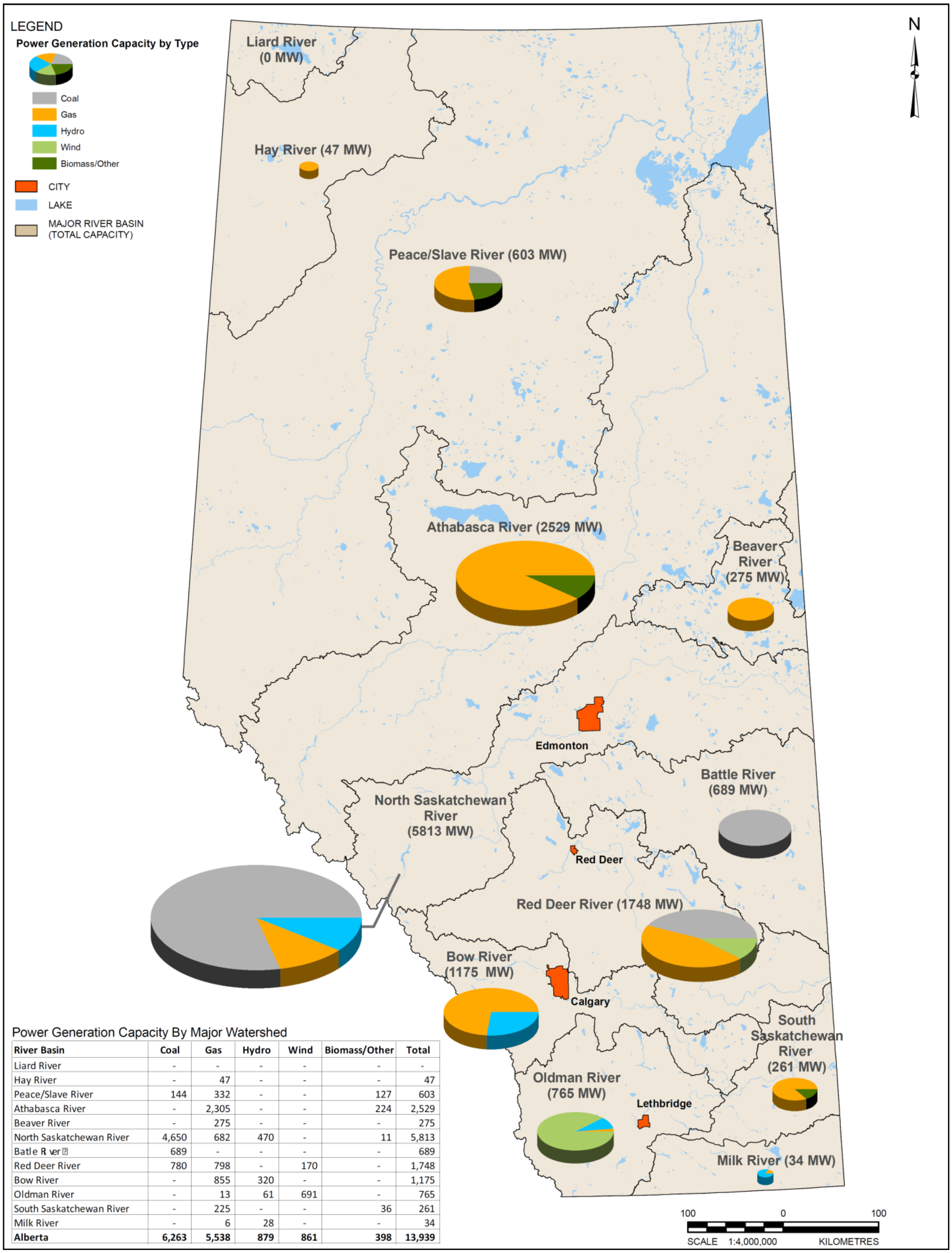
Electricity demand in Alberta has grown at a rate about equal to adding two cities the size of Red Deer each year since 2001. The growth of power generation (MWh) in Alberta since 2000 is shown on Figure 3. This growth has coincided with a gradual reduction in coal generation (MWh) and increase in natural gas generation (MWh), as shown in Figure 4.



Source: AESO Annual Net Capacity (MW) Data, (AESO, 2011)

Figure 1: Alberta Generation Capacity (MW) by Generation Type in 2011

Genesee Thermal Generation Facility

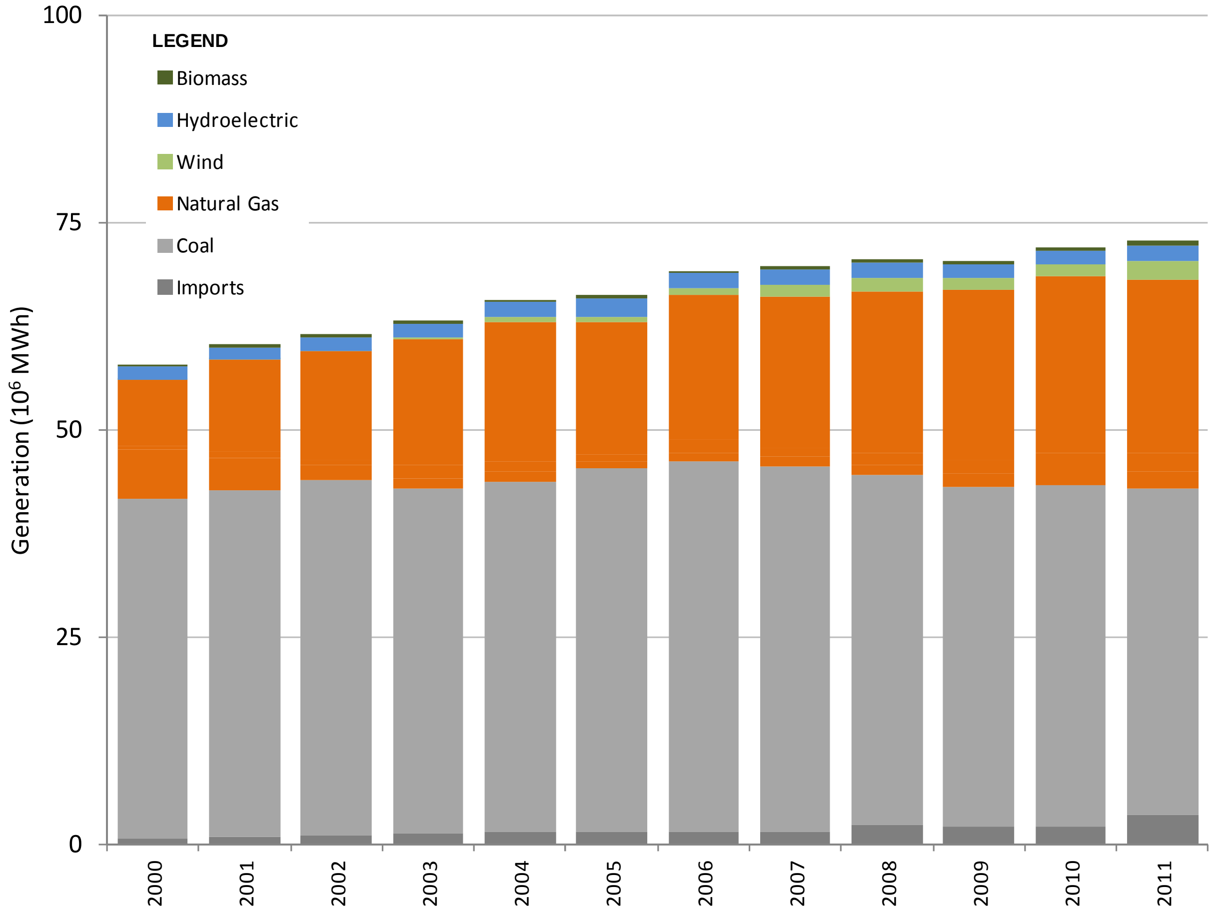


Power Generation Capacity By Major Watershed

River Basin	Coal	Gas	Hydro	Wind	Biomass/Other	Total
Liard River	-	-	-	-	-	-
Hay River	-	47	-	-	-	47
Peace/Slave River	144	332	-	-	127	603
Athabasca River	-	2,305	-	-	224	2,529
Beaver River	-	275	-	-	-	275
North Saskatchewan River	4,650	682	470	-	11	5,813
Batle R ver	689	-	-	-	-	689
Red Deer River	780	798	-	170	-	1,748
Bow River	-	855	320	-	-	1,175
Oldman River	-	13	61	691	-	765
South Saskatchewan River	-	225	-	-	36	261
Milk River	-	6	28	-	-	34
Alberta	**6,263**	**5,538**	**879**	**861**	**398**	**13,939**

Source: AESO Market Statistics for Total Capacity (MW) by Unit, (AESO, 2011)

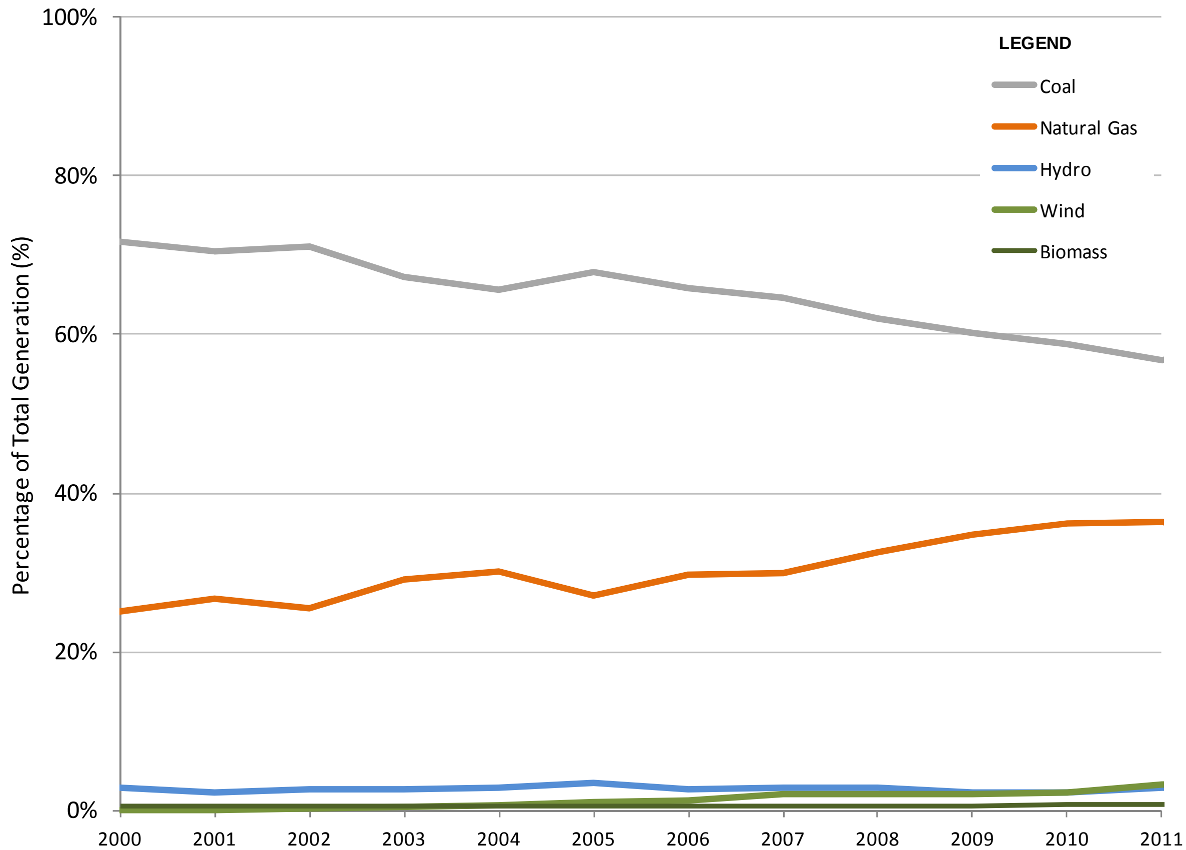
Figure 2: Location of Power Generation Capacity (MW) by Watershed



Source: AESO Annual Net Generation (MWh) Data, (AESO, 2011)

Figure 3: Growth of Alberta Power Generation (MWh) from 2000 to 2011

Sundance Thermal Generation Facility



Source: AESO Annual Net Generation (MWh) Data, (AESO, 2011)

Figure 4: Generation Mix (based on Generation in MWh) from 2000 to 2011

Coal

Alberta has six coal-fired power generation plants with a total installed capacity of 6,263 MW. The three largest coal-fired plants (Keephills, Sundance and Genesee) are located along the same coal formation in the Wabamun-Genesee region and use water from the North Saskatchewan River. The three other coal-fired facilities (H.R. Milner, Sheerness and Battle River) use water from the Smoky, Red Deer and Battle Rivers, respectively. The majority of these power plants are located adjacent to coal mines, developed specifically to serve the power plants.

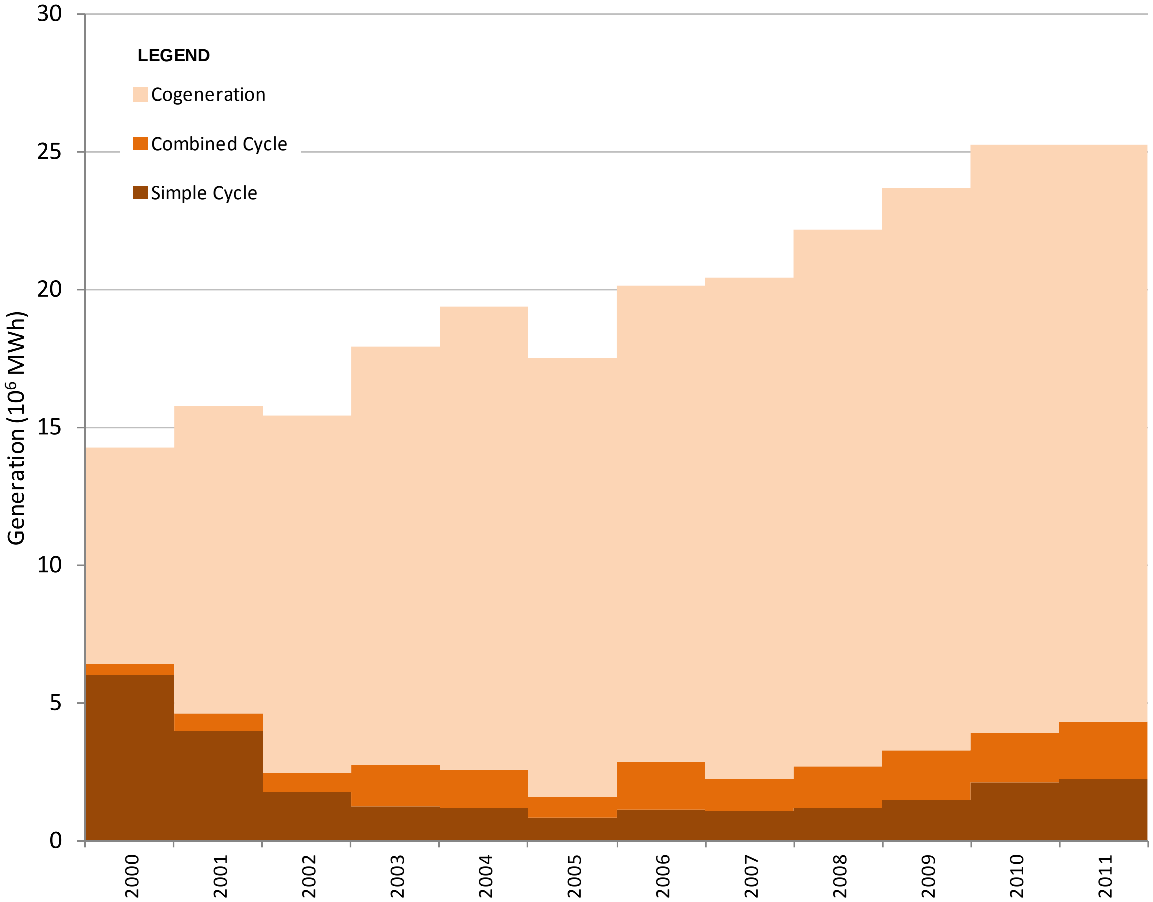
In a coal-fired power plant, power is produced by burning coal in a boiler to boil water. Boiling water creates steam that travels through pipes into a steam turbine. The steam turbine spins a generator and creates an electrical current. A detailed description of coal power generation and associated water consumption can be found in Appendix A.

Keephills Thermal Generation Facility

Natural Gas

Gas-fired generators in Alberta can be divided into four categories: simple cycle gas turbine plants, combined cycle plants, co-generation plants, and boiler plants. Boiler facilities use natural gas to fire a boiler and create steam that is used to generate electricity, in the same process used in coal-fired facilities. This type of gas-fired generation has mostly retired from the electric system, although more gas-fired electricity generation boilers could be constructed in the future. Figure 5 shows the amount of power generation (MWh) for the simple cycle, combined cycle and co-generation facilities in Alberta from 2000 to 2011.

Current gas-fired generation plants use gas turbines, which produce power by taking air in, compressing it, and then heating it by burning natural gas. The heated air is allowed to expand through the gas turbine, causing the turbine and the attached generator to turn and creating an electrical current. A detailed description of natural gas power generation (simple cycle, combined cycle, and co-generation) and associated water consumption can be found in Appendix A.



Source: AESO Annual Net Generation (MWh) Data, (AESO, 2011) **and ERCB (2011)**

Figure 5: Natural Gas Generation Mix (based on Generation in MWh) from 2000 to 2011

Simple Cycle Gas Turbines

Current simple cycle gas turbines have a short start-up time. The ability to ramp up and down rapidly makes them well-suited to provide capacity quickly in response to demand (peaking capacity) and operating reserves for the Alberta electric system.

Combined Cycle Plants

Combined cycle plants are generally more efficient than simple cycle gas turbine generators, because they use waste heat to produce steam to generate additional electricity. As a result, combined cycle plants are more complicated and may not start as quickly as simple cycle plant, but they are well suited for an intermediate role between base load and peaking generation.

Valleyview Gas Turbine Facility

Co-generation

Co-generation is the simultaneous generation of electric power and thermal energy for an external process. Several configurations of power generation and heat production are possible, but the most common in Alberta is the combination of a gas turbine generating power connected to a heat recovery steam generator where the waste heat is used to produce steam or hot water for use in an industrial process. Using waste heat to produce high quality steam leads to a very high operating efficiency for a co-generation facility. On the other hand, in this operating scenario the industrial process steam is the primary product, which reduces the flexibility of the generator to react to electricity market conditions. Most cogeneration facilities are base loaded.

Co-generation is common in the growing oil sands industry where many new developments include co-generation in their plant designs. Oil sands extraction operations have substantial heat and electricity requirements and provide an opportunity to install co-generation facilities with power output that often exceeds the needs of the extraction and associated upgrading facilities.

Joffre Cogeneration Facility

Hydroelectric

Alberta has a total installed hydroelectric generation capacity of 915 MW, or about 7% of the installed capacity in the province. The majority of this total, 789 MW, were brought online between 1911 and 1972 (AESO, 2009b). The Bow River Hydro System comprises 11 individual plants on the Bow River and several of its tributaries located between Banff and Calgary. Two other hydro plants are located in the North Saskatchewan River basin: Brazeau and Bighorn. The remaining hydro capacity is located at several separate plants ranging in size from small run-of-river micro hydro projects (less than 1 MW) to larger hydroelectric projects such as the 32 MW Oldman River project. These relatively small hydro projects typically do not have significant storage (reservoirs), often utilize storage for irrigation during the summer months, and/or operate with a low capacity factors (AESO, 2009b). There is potential for additional hydroelectric facilities in Alberta.

Hydroelectric plants often have a significant role in peaking/reserve electricity supply (AESO, 2009b). In hydroelectric facilities, power is generated by using the potential and kinetic energy of water. The level of water created by dams creates pressure that pushes against turbine blades causing the hydro turbine to spin, producing electricity. A description of hydroelectric plants and associated water consumption can be found in Appendix A.

Oldman River Hydro Facility

Wind

Wind power in Alberta has seen substantial growth in the last few years. As of 2011, Alberta had 787 MW of transmission-connected wind power.

Power is generated by harnessing the energy from the wind with wind turbines. A wind turbine is placed on top of a high tower and when the wind blows it spins a generator, creating electricity. Wind power is an intermittent source of energy and the amount of power generated by wind turbines is highly dependent on the wind speed. A detailed description of wind turbines and associated water consumption can be found in Appendix A.

Wind Turbine near Pincher Creek

Biomass

Alberta currently has biomass power facilities with a total capacity of about 378 MW. Wood waste from pulp and saw mills is the primary fuel for biomass generation plants in Alberta. Landfill gas and a small amount of agricultural waste are also used for fuel. Generation from biomass is generally restricted to locations at the source of the fuel due to transportation costs.

A biomass power plant can use these fuels in a boiler to create steam. The pressure of the steam spins a steam turbine attached to a generator, which creates electricity. A detailed description on biomass power plants and associated water consumption can be found in Appendix A.

Cloverbar Landfill Gas Facility

2.2 Water Use Profile

2.2.1 Description of Key Water Use/Users

Water Use Processes

The power generation sector uses water in many different ways. Water can be used to directly generate power (i.e. hydroelectric generation) or to support the generation processes in the thermodynamic cycle such as cooling for combined cycle natural-gas fired power plants.

Within the power sector itself, the predominant use of water is for cooling, although uses for the steam generated in boilers associated with power generation is constantly increasing for uses such as co-generation associated with oil sands production using Steam Assisted Gravity Drainage (SAGD). Table 1 outlines the water consumption processes used for the various power generation types in Alberta. Appendix A outlines the processes for water diversion and consumption by power generation type.

Hydroelectric power generation facilities do not consume water in a typical manner compared to other generation technologies. Water loss at hydro plants is associated with evaporation from the reservoir – evaporation that would otherwise not occur if the reservoir did not exist. These evaporative losses represent a form of consumptive use since the evaporated water is returned to the environment, but not directly returned to the river.

Overall, about 80% of the water consumption by power generation is typically required for cooling mechanisms (EPRI, 2002). For thermal electric power generation, (generation where steam is the primary driver), the amount of water consumed is largely dependent on the type of cooling process. In Alberta, two types of cooling processes have been used; "once-through" and "closed-loop". A detailed description and comparison of various cooling processes and technologies used for thermal electric power generation can be found in Appendix B.

Table 1: Water Consumption Processes by Generation Type

Water Use Process	**Coal**	**Natural Gas**			**Hydro**	**Wind**	**Biomass**
		Simple Cycle	*Combined Cycle*	*Co-gen.*			
Boiler/ makeup water	♦		♦	♦			♦
Cooling water	♦		♦	♦			♦
General service water	♦	♦	♦	♦			♦
Potable water use	♦	♦	♦	♦	♦		♦
Site surface drainage or evaporation from an impoundment	♦	♦	♦	♦	♦		♦

Once-Through Process

Once-through cooled plants divert large quantities of water from a source, but the majority of that water is returned to the source with only the addition of heat. Only a small quantity is consumed via increased evaporation to the atmosphere from the warmed discharge water plume (EPRI, 2002). The cooling water flow rate is typically designed around a maximum allowable temperature increase (above ambient water) or maximum return water temperature, as authorized by water quality regulations.

In Alberta there are a few power facilities which use a once-through cooling process. For example, the HR Milner Generating Station, a coal-fired power station, near Grande Cache is characterized as having a cooling system which uses a once-through process.

Closed-Loop Process

Plants that use a closed-loop process, also known as a re-circulated system, have much lower water diversion rates than plants with once-through cooling, but a large amount of the withdrawn water is evaporated through a cooling tower or pond (EPRI, 2002). The evaporation process can result in a slightly higher concentration of dissolved and suspended solids and temperature changes in the return flow, all of which are managed by regulations.

2.2.2 Baseline Water Use

Water License Regulations

The *Water Resources Act* of 1931 was based on a first-in-time, first-in-right (FITFIR) priority system designed to promote new development and protect existing development. Water licenses issued under the *Water Resources Act* typically did not have an expiry date and some of these licenses are still in existence today.

In 1999, the *Water Resources Act* was replaced by the *Water Act*, which was designed to promote water conservation while recognizing the need for economic growth and prosperity. Under the *Water Act*, a license is required to divert large volumes of surface water from rivers, lakes or ponds, and from non-saline groundwater in underground aquifers. Water licenses granted in Alberta after the *Water Act* was introduced in 1999 all have expiry dates. Typically, a new water license will expire after five or ten years and must be renewed. Other Temporary Diversion Licenses (TDLs) can be active from weeks to a year, with an option to extend for up to one additional year.

This shift in the regulatory context for water management is also reflected in the adoption of *Water for Life: Alberta's Strategy for Sustainability* (Alberta Environment, 2003a) as a policy for water management in Alberta.

Water licenses typically limit the maximum annual volume and the instantaneous peak rate of water diversion, as well as other site-specific conditions. Approvals may also specify a return flow that must be discharged back to the environment and the quality of water returned to the environment.

When required by licenses and approvals, licensees must retain records of water use and report their actual water use. Alberta Environment and Sustainable Resource Development (AESRD) has developed an online reporting system to document water use information.

There are also provisions under the *Water Act* to refer an application for review under the *Environmental Protection and Enhancement Act* (EPEA). Compliance with certain sections of the EPEA is mandatory for issue or amendment of an approval or license under the *Water Act*.

Water Availability

The relative availability of water throughout the province depends on both the water availability and the amount of water that is allocated for use. Overall, the northern portions of Alberta have high availability and low demand, while higher percentages of the natural flow are allocated in southern regions. This is illustrated on Figure 6 as darkly-coloured water-short areas in southern Alberta.

Water availability is described in *Water Supply Assessment for Alberta* (Golder Associates, 2008) and in the AESRD report *Water-short Areas Assessment* (Alberta Environment, 2006a). To identify water-short areas in Alberta, Alberta Environment (2006a) defined three categories:

- Water-short: considered either exceptionally dry, or the area/watershed has been closed to most or all new water applications;
- Potentially water-short: considered either relatively dry, or the area/watershed has a generally high level of allocations compared to natural supply; and

- Not regionally water-short: areas that are not observed as regionally water-short, but some water-short areas may be present locally.

The water-short areas are situated primarily in the South Saskatchewan River Basin (SSRB), which includes the Bow River, Oldman River, Red Deer River, and South Saskatchewan River sub-basins. With the exception of the Red Deer River sub-basin, the SSRB was closed to new surface water licenses in 2006 (Alberta Environment, 2006b).

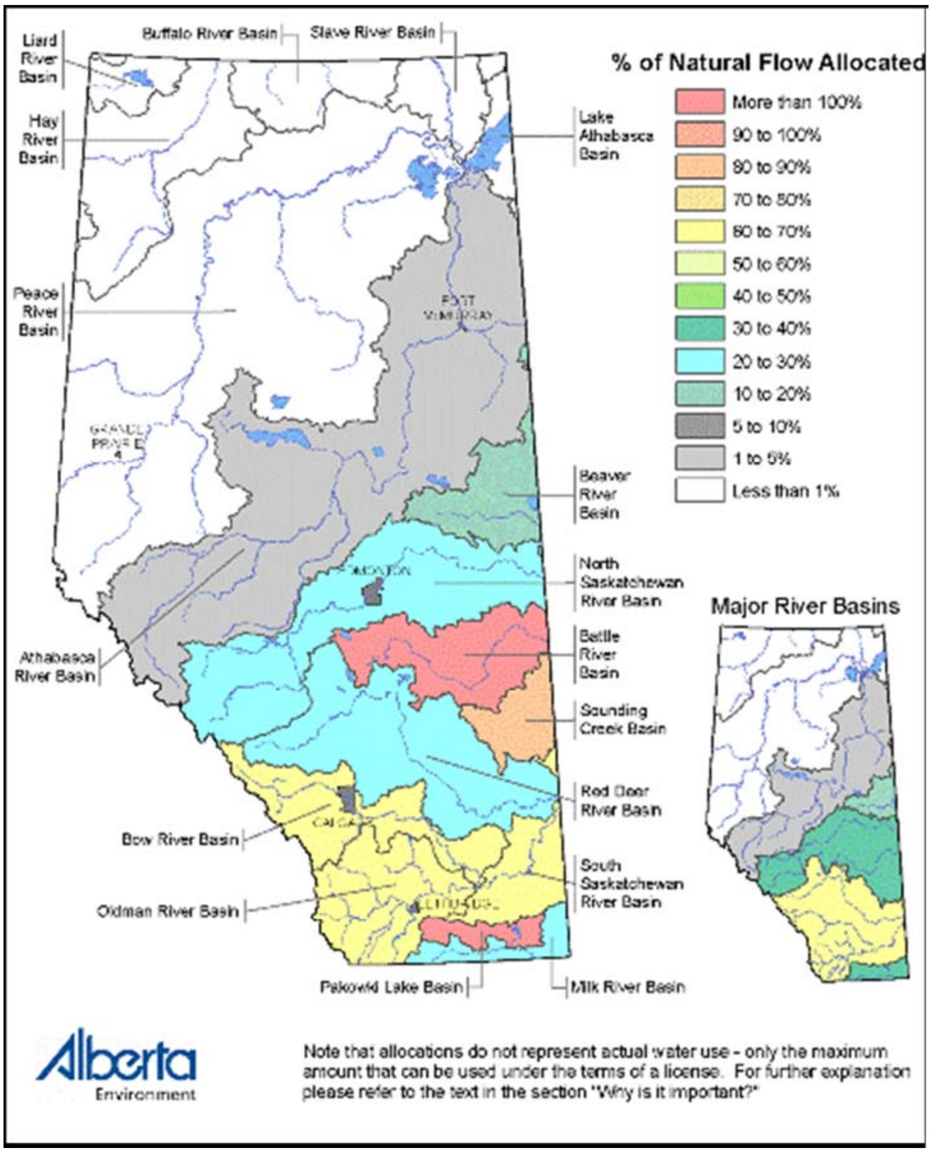
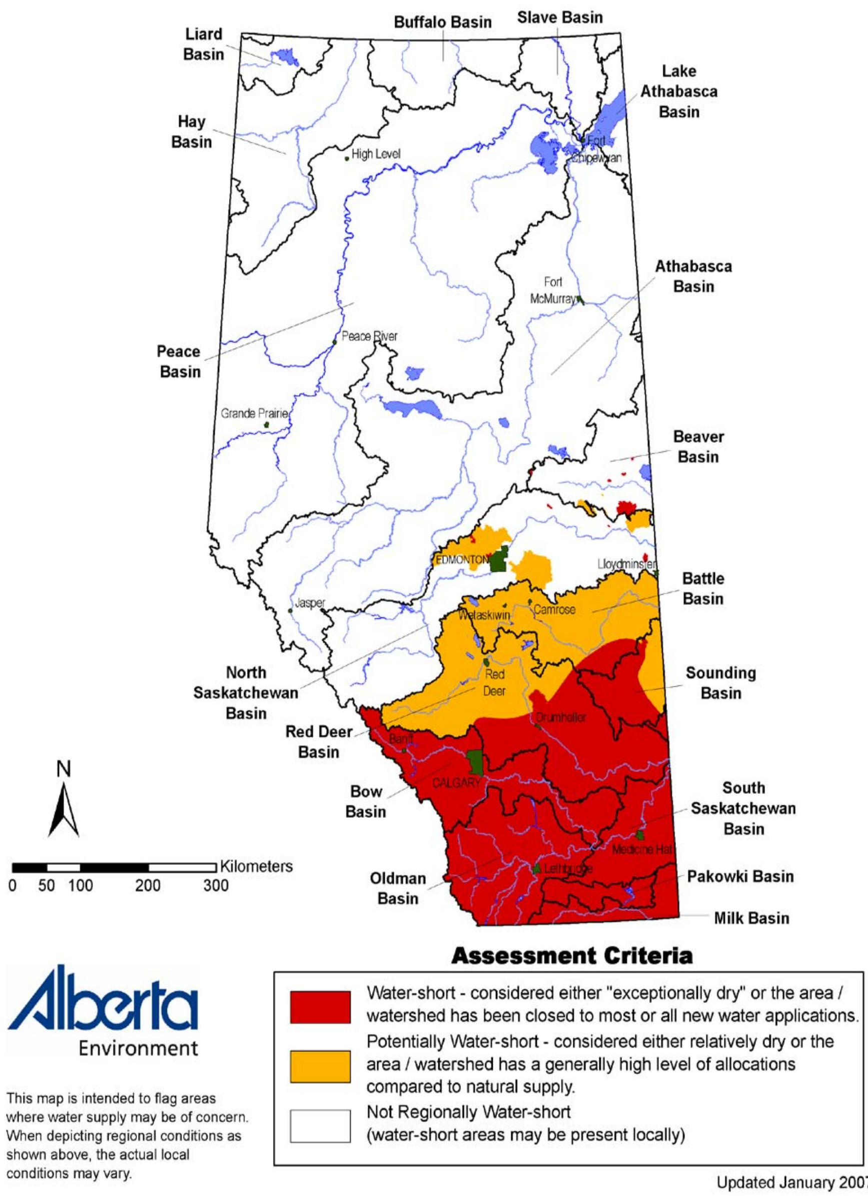


Figure 6 [a & b (below)]: <u>Distribution of Water Licenses</u> and Water-Short Areas in Alberta (2006)

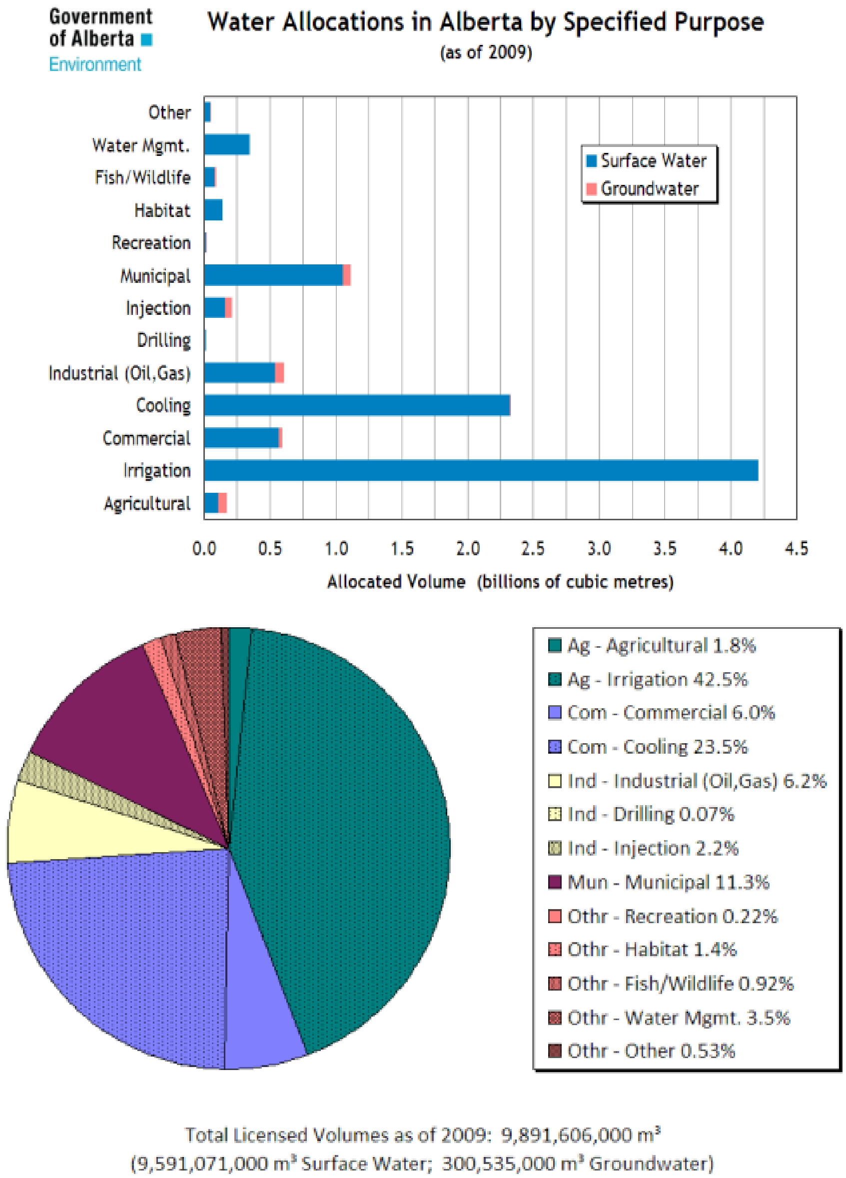


Source: Alberta Environment, 2006a

Figure 6 [a (above) & b): Distribution of Water Licenses and <u>Water-Short Areas</u> in Alberta (2006)

Water Licenses

In 2009, Alberta's total water allocation was 9.9 billion cubic metres (Bm^3): 97% from surface water sources, and 3% from groundwater sources. The largest water users in Alberta by purpose are irrigation, followed by cooling and municipal. As illustrated in Figure 7 which shows water licenses in Alberta, agriculture and irrigation account for 44.3% of the provincial water allocation, cooling accounts for 23.5% (commercial and industrial cooling), municipal use accounts for 11.3%, and 8.5% is allocated to the oil and gas industry (i.e. industrial, injection and drilling).

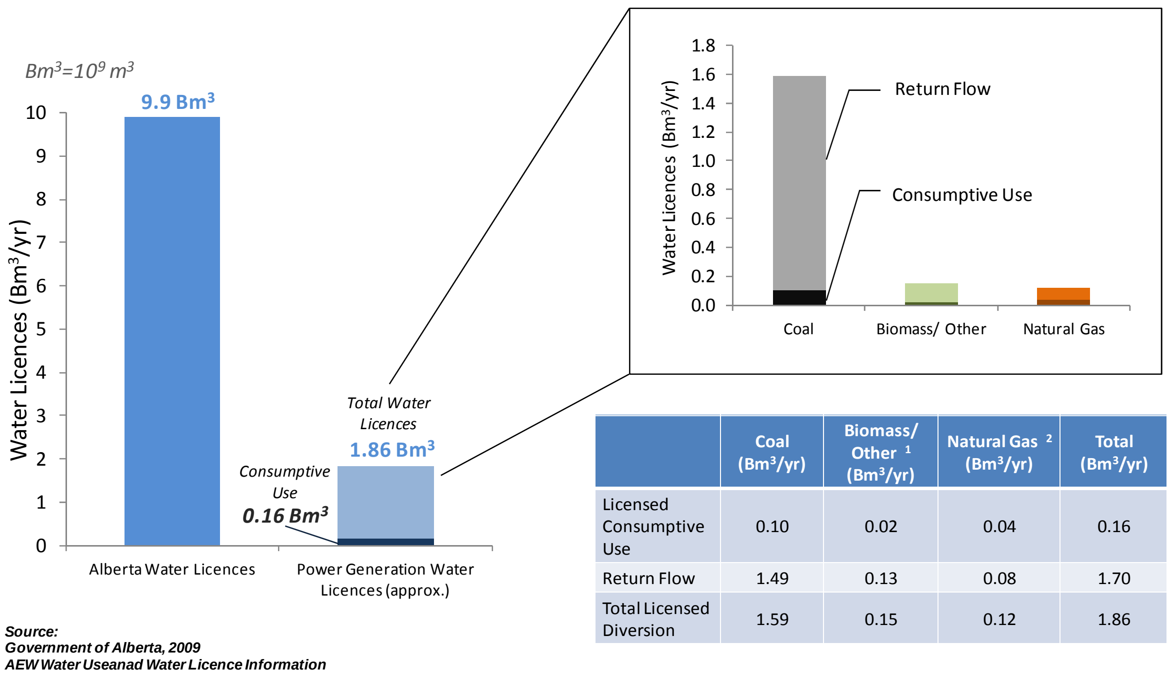


Source: Alberta Environment, ***2009***

Figure 7: Water Licenses by Sector in Alberta (2009)

Power Sector Water Licensing and Water Use

The power generation water licenses are estimated to be around 1.86 Bm^3/year, not including hydroelectric power generation. These licenses are mostly categorized within the "cooling" category shown on Figure 7. Only a fraction of the water is consumed in this category; the majority is returned to the original water source. A breakdown of power generation licenses is shown on Figure 8, based on available estimates. In some cases, water licenses include water use for more than power generation (e.g. co-generation for oil sands). Therefore, the total water license volume shown on Figure 8 may include water for purposes other than power generation.



	Coal (Bm^3/yr)	Biomass/ Other [1] (Bm^3/yr)	Natural Gas [2] (Bm^3/yr)	Total (Bm^3/yr)
Licensed Consumptive Use	0.10	0.02	0.04	0.16
Return Flow	1.49	0.13	0.08	1.70
Total Licensed Diversion	1.59	0.15	0.12	1.86

1. Biomass/Other power generation includes only licenses associated with generation units listed by the AESO . The licensed water allocation and use includes other industrial purposes other than electricity generation.
2. Natural gas generation includes only licenses associated with generation units listed by the AESO that are described as "other/cooling". This may include some water used for other purposes and not solely power production.

Source: Alberta* Environment *and Sustainable Resource Development License Records and Water Use Reporting (2011)

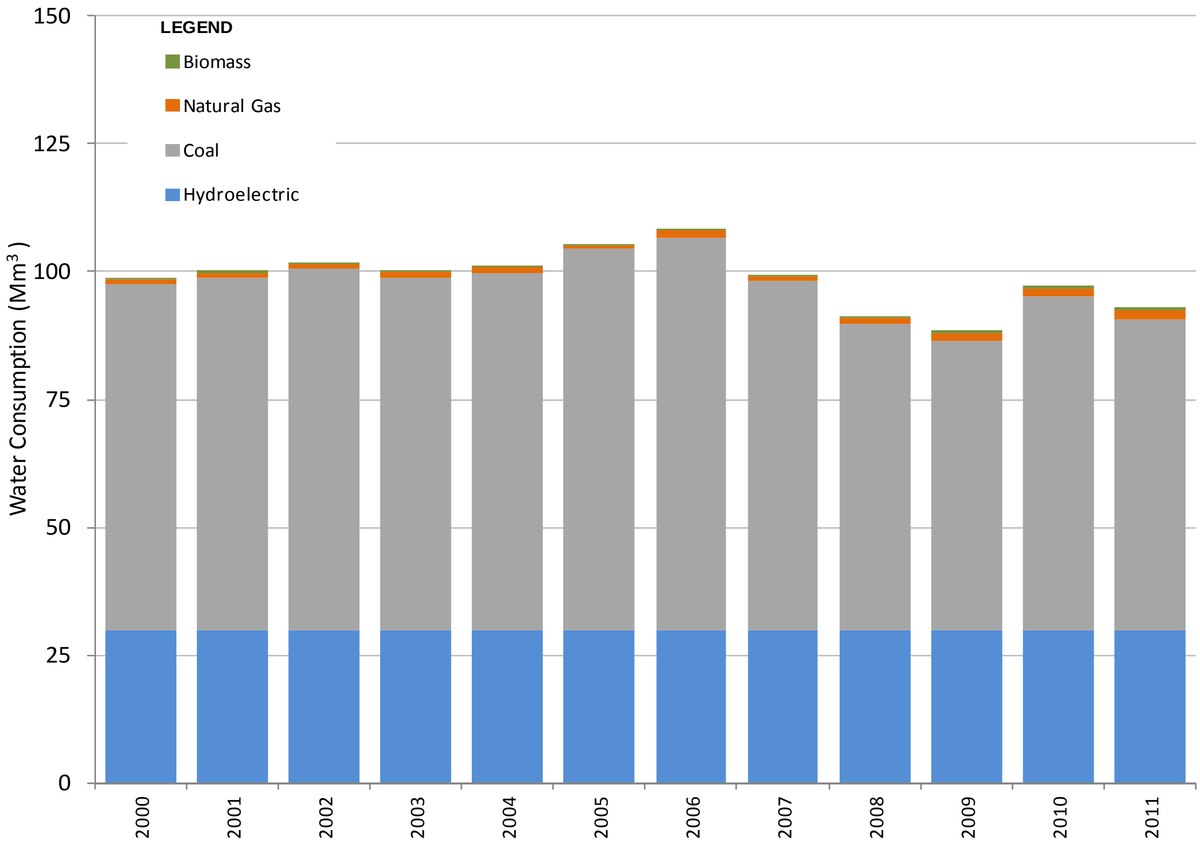
Figure 8: Water Licenses Related to Power Production

Water Sources

Water for power generation, depending on the location and nature of the operation, is generally sourced from surface water, including rivers, lakes, and ponds. There is little reliance on groundwater sources.

Estimated Water Use

For the purposes of the CEP Plan a baseline period of 2000-2002 was chosen, because this period reflected both the availability of reasonably comprehensive data and the start of a natural transition in electric power generation technologies. For the baseline period, water consumption was estimated to be about 100 million cubic metres (Mm^3), as shown in Figure 9. Coal power generation uses the majority of water (over 70%), followed by hydroelectric generation, which accounts for about 30% of the total water consumption.



Source: AESO Annual Net Generation Data, 2011, ERCB **Data (2011), AESRD Water Use Information for Coal (2005 to 2011), and ETIPRG (2010) water consumption rates**

Figure 9: Estimated Sector Water Consumption (Mm^3) By Generation Type from 2000 to 2011

The actual water use by the power sector, in terms of water consumption (i.e. water diversion minus return flow), was estimated based on a combination of available water use reporting information and typical unit rates from the literature. This combination of methods was necessary due to limited actual water use data available from AESRD. A key deliverable of the CEP Plan is to provide a reasonable methodology to estimate water use where actual information may not be available. This is intended to provide a reasonable baseline and future benchmark of CEP performance.

Water use reporting information available from AESRD for the power sector in Alberta is summarized below. The AESRD database was queried and the retrieved information was reviewed for use in this CEP Plan.

- **Coal:** Water use reporting was mostly complete from 2005–2011 and largely inconsistent from 2000–2004.
- **Biomass and natural gas:** Water use records often incorporated multiple purposes. Some licenses for gas-fired plants stipulated the purpose as "cooling," and this was assumed to relate to cooling for power production and not for other industrial purposes.

Some natural gas-fired power plants (e.g. Medicine Hat, Calgary Energy Centre, industrial cogeneration) use water under a license categorized under a different usage (e.g. urban water supply, industrial usage). In this latter case, the electricity production was included in the CEP Plan, but the water usage associated with industrial processes other than power production were not. Water use reporting for these facilities was incomplete.

- **Hydroelectric:** Water use (diversion and return flows) information was not available from AESRD.

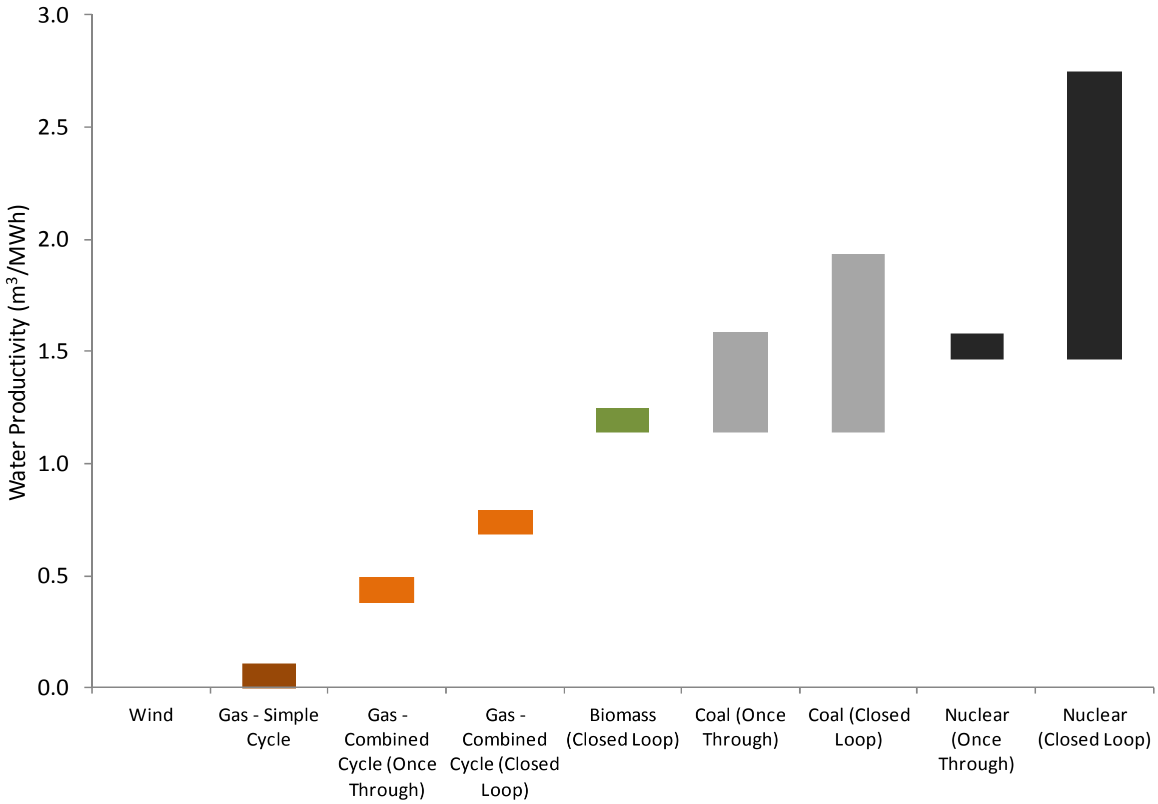
Where water diversion and return flow information was not available for coal, biomass or natural gas-fired power plants, water consumption was estimated using available typical rates. Typical unit rates of water use per unit of electricity produced (m^3/MWh) were used. Electricity production was based on generation information available from the AESO's market statistics reports. Typical water consumption rates for coal, natural gas, biomass and nuclear power plants have been published by various organizations (e.g. Energy Technology Innovation Policy Research Group, 2010; Virginia Water Resources Research Center, 2008; NETL, 2009; NETL, 2011; NREL, 2003; USDOE, 2006). For this CEP report typical unit rates were assumed based on the Energy Technology Innovation Policy Research Group (ETIPRG 2010). Figure 10 shows the comparison of the various generation types and the associated unit rate or water productivity rate (m^3/MWh). Water consumption for Alberta generation units were generally within the range of published typical rates.

The typical water consumption rates (in m^3/MWh) selected for this CEP Plan are summarized below.

- **Coal:**
  - Actual water use records from 2005 to 2011;
  - 1.55 m^3/MWh 5-year average of water use records for missing information between 2005 and 2011;
  - 1.65 m^3/MWh from 2000 to 2004, based on average water use records from 2005 to 2008 (within the range of typical rates); and
  - 1.50 m^3/MWh from 2012 to 2029 was forecast, based on average water use records from 2009 to 2011 (within the range of typical rates).
- **Natural Gas:**
  - Simple cycle: 0.11 m^3/MWh, a relatively low average rate because simple cycle plants may not require cooling, but may require water for air emission management;
  - Combined cycle: 0.74 m^3/MWh based on cooling requirements using cooling towers; and
  - Co-generation: These facilities are often embedded within industrial facilities that have water licenses for other purposes, such as the generation of process steam. The significant majority of the water consumed is not associated with power generation and all water consumed is generally managed under licenses held by the industrial or municipal process. The electricity production was counted in the CEP Plan; however, to avoid double-counting water use, the water usage was not.
- **Biomass:**
  - 1.19 m^3/MWh based on cooling requirements of a typical steam turbine closed-loop system.

- **Nuclear:**
    - There is currently no nuclear energy production in Alberta.
- **Hydroelectric:**
    - An average annual water consumption of 30 Mm^3 was estimated as the net evaporation from all of the hydro reservoirs combined, with a resulting water productivity factor ranging from 14.5–21.9 m^3/MWh. This water productivity factor is similar to the typical range of 5–27 m^3/MWh published by ETIPRG (2010), but is expected to be conservatively high due to the local climate and relatively high elevation of most of Alberta's hydropower dams compared to the referenced climate station locations.
    - The overall estimate of water consumption for hydropower production does not include evaporation at hydropower facilities where the primary purpose is flood control or water supply (e.g. irrigation).

  The estimate also does not account for climate variability. For example, net evaporation would be relatively low in cool and wet seasons, and much higher in hot and dry seasons.



Source: Energy Technology Innovation Policy Research Group (2010)

Figure 10: Typical Water Consumption Unit Rates (m^3/MWh) for Various Generation Types

2.3 Linkages with Other Water Systems and Operating Parameters

Power generation can be synergistic with other water purposes and systems. This is dependent on the location, proximity to other water users and the nature of the processes and technologies involved. For example, synergistic benefits may include: recycling of diverted water, reduction in intake and return facilities, recreation use, sharing of or management of water storage or collection resources, flood control benefits or seasonal downstream flow augmentation of low flow and water supply security.

2.4 Review of Current Policies, Programs, Plans and Legislation

2.4.1 Related Policies, Programs and Plans

In addition to the *Water for Life* strategy (see Section 1.1), there are a number of federal and provincial regulations, policies, programs, and plans that influence water use by the power generation industry in Alberta. Some of these are only indirectly related to water use, but nevertheless impact the need for and use of water.

Rainbow Lake Combined-Cycle Facility

For example, the power generation sector has worked with interested parties to address local issues and developed a framework for air emissions management through the Clean Air Strategic Alliance (CASA). This framework identified the long-term requirements for existing fossil fuel-fired facilities from an emission perspective and in doing so identified related issues that could affect water use for power generation (CASA, 2007).

2.4.2 Related Legislated Conditions or Clauses

Existing Regulations

Significant water regulations for the Alberta power industry include the Alberta *Water Act*, the Alberta *Environmental Protection and Enhancement Act*, the *Public Lands Act*, the *Canadian Environmental Protection Act*, the *Canadian Environmental Assessment Act*, the *Fisheries Act*, the *Navigable Waters Protection Act*, and others.

Regulations pertaining to power production include *Alberta Utilities Commission Ac*t, *Electric Utilities Act*, *Gas Utilities Act*, *Hydro and Electric Energy Act*, and the *Small Power Research and Development Act*.

Proposed Regulations

The future of the power generation sector in Alberta will be impacted by proposed federal and provincial legislation relating to air quality, the environment and water use. While the overall impact on water consumption has not yet been determined, there is significant potential for water consumption increases due to these pending regulations.

Environment Canada has recently issued a regulation to establish a regime for the reduction of carbon dioxide (CO_2) emissions resulting from coal-fired electricity generation. The "*Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations,*" is under the *Canadian Environmental Protection Act*, 1999 (CEPA, 1999). The proposed regulation will require coal-fired power units that reach the age of 50 years to either: (i) meet a CO_2 performance standard of 0.420 tonnes/MWh, (ii) fuel switch, or (iii) close. The proposed regulation will affect the life of coal-fired units; the emissions control equipment required to operate and could have a significant impact on power generation water consumption.

Environment Canada is also currently reviewing industrial air emission requirements and controls and is focused on establishing Base-Level Industrial Emissions Requirements (BLIERs) in major industrial sectors, including the electricity sector. Standards for the electricity sector are expected for:

- Sulphur Dioxide (SO_2);
- Nitrogen Oxides (NO_X);
- Volatile Organic Compounds (VOCs); and
- Total Particulate Matter (TPM).

BLIERs may include any of these individually or in combination:

- Equipment standards;
- Process standards;
- Facility standards; and
- Fuel-based standards.

BLIERs are intended to be quantifiable requirements that can be imposed by regulations or permits on existing and new facilities. They should be quantitative performance standards, and may be developed on an equipment basis and then rolled up to a facility level. Due to the unknown impact of these requirements in their final form and the new emission control requirements, there is significant uncertainty in what might be expected for control equipment on new and existing electricity generation equipment. Water consumption varies significantly with different emission control technologies.

2.5 Sector History of Water Conservation, Efficiency, and Productivity

Overview

The power generation sector has been a strong proponent of water CEP. In addition to environmental benefits, water CEP often has economic benefits. Industry has been considering these kinds of measures for many years, and steps to reduce water consumption have been taken at power generation facilities by implementing process changes and technology upgrades.

All coal-fired plants constructed since the early 1980s have featured closed loop cooling (cooling ponds), rather than once-through cooling.

Examples of Water Savings

In power generating stations examples of water savings already realized include the following initiatives.

- Higher efficiency equipment and components have been installed to increase efficiency and either reduce water consumption, or increase electricity production at the same water consumption levels (i.e. reduce water use intensity):
    - A dense pack (steam turbine improvement) installation at Battle River and Sheerness and upgrades to Sundance turbines increased operating efficiency resulting in more power generated per unit of water used; and
    - A soot blower optimization project at Battle River reduced water consumption without impacting the operation of the boiler;
    - Hydro facility turbines have been upgraded and refurbished with more efficient units producing more energy from the same volume of water.
- Wabamun Units 1, 2, 3 and 4, were retired and replaced by newer technology;
- Clover Bar gas-fired boilers required water cooling and were shut down and replaced by aero-derivative gas turbines;
- New technologies for power plants use are more efficient and produce more energy without requiring additional water. Examples include the Genesee 3 and Keephills 3 plants. These are both high-efficiency supercritical technology plants;
- At Joffre, a planned 2012 initiative to add a waste water recycle loop to the cooling tower will provide a savings on the water-to-product ratio, and a more significant saving in effluent-to-product ratio;
- Power facilities have optimized boiler blowdown water chemistry to allow re-use of cooling water without scaling problems.
- Cooling ponds have been utilized at some facilities to allow reuse of water for cooling, minimizing the thermal impact on the aquatic habitat by removing thermal energy in the cooling water prior to return.
- A number of transmission lines have been built. Improvements to the transmission infrastructure help to minimize transmission losses over long distances while meeting generation needs in different regions of the province.

Examples of Water Quality and Fish Habitat Improvements

In addition to water savings, there have been improvements in water quality and fish habitat in the power generation sector within the past ten years. For example, the Battle River station implemented a fish protection program which included reduced chemical usage and the installation of a fish barrier at the outlet of the cooling canal. Recently, new fish intake screens were installed on all pumphouse intakes at the Battle River plant. These measures have led to fewer impacts to fish in the cooling canal and at the pumphouse intakes. In addition to these improvements, the facility has altered polymers, dispersants and phosphate used in the cooling tower, allowing additional cooling cycles for each volume of water used. This has improved water consumption per MWh generated.

Over the past several years, the electricity sector has begun to conduct intensive environmental monitoring on a regional scale. For example, in the Wabamun-Genesee regional area, effects on terrestrial and aquatic habitat and biota have been extensively monitored, including impacts from the water returned to the North Saskatchewan River. The monitoring began when there were four generating stations in the region, the highest concentration of coal-fired power plants in the province. These studies have established a baseline and continue to monitor impacts on a five-year interval coinciding with startup of Genesee 3, shutdown of Wabamun and startup of Keephills 3. In addition to the Regional Bio-Monitoring studies, additional studies are underway to measure the incremental impact of Keephills 3 on the North Saskatchewan River.

Battle River Thermal Generating Facility

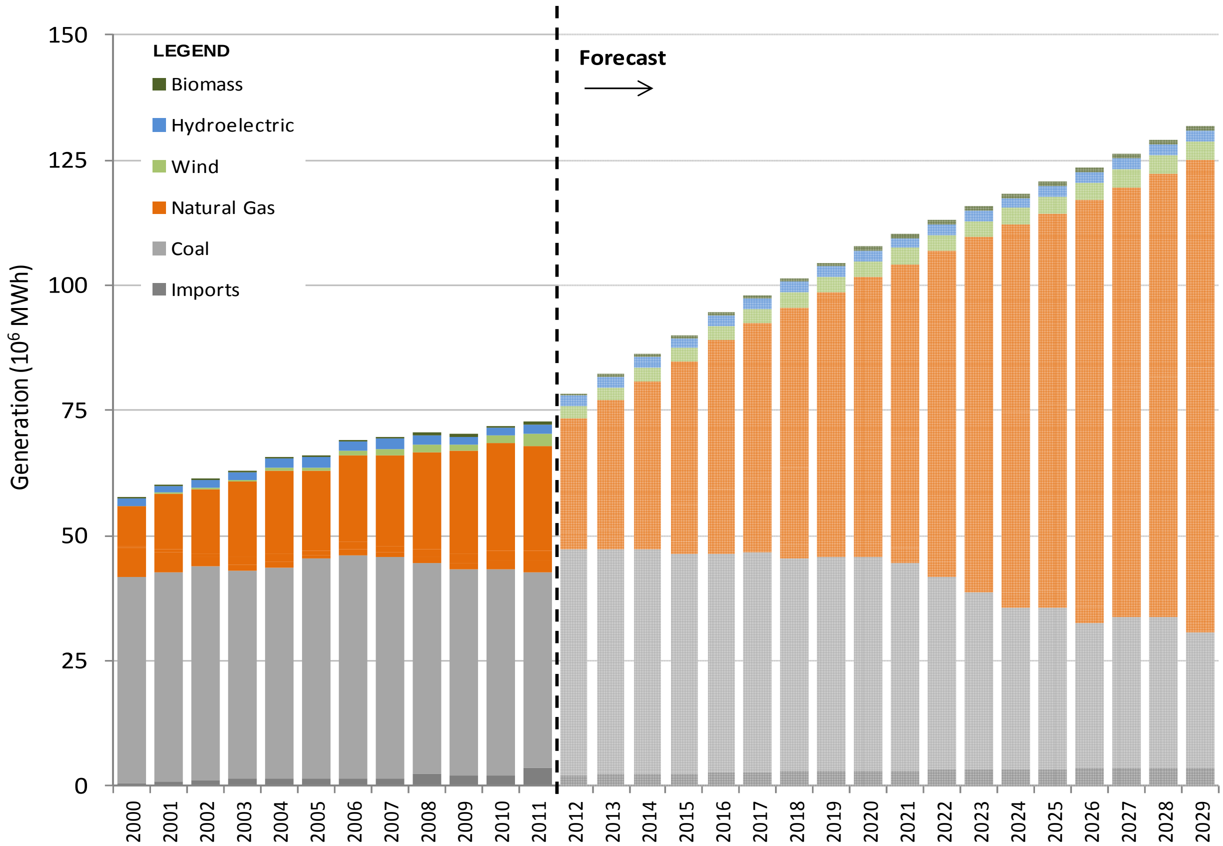
3 Water Supply and Demand Considerations

3.1 Water Demand Forecasting

The following section describes a power sector water forecast through 2015 in accordance with AWC recommendations, which was extended to 2029 to illustrate the likely future trends taking into consideration pending GHG regulations. The methodology and assumptions for forecasting water demand are based on the current AESO power generation forecast and projected unit rates of water consumption (i.e. typical industry water consumption per unit of production). The water consumption forecast does not include estimates of total water diversion and return flow.

Power Generation Forecast

The water forecast is based in part on the power generation forecast summarized in Figure 11. Power generation is expected to increase by about 50% between the baseline years (2000 to 2002) and 2015, and increasing by about 100% over the baseline years by 2029. The generation forecast is largely based on the energy forecast published as the AESO *Future Demand Energy Outlook (2009-2029)* (AESO, 2009a). This energy forecast was produced in 2008 prior to the economic downturn in the last decade and as a result there is a noticeable difference between the 2011 actual energy demand and the 2012 forecast energy demand values. It should be noted that the forecast is based on a probabilistic estimate or expected value of the energy demanded in the future, which is bounded by a range of alternative outcomes. The forecast will change with changes in assumptions in every forecast year. The forecast is considered to present one reasonable estimate of future demand.



***Source: AESO Annual Net Generation (MWh) Data (2011),* ERCB Data (2011), AESO Future Demand and Energy Outlook (2009-2029)**

Figure 11: Forecasted Power Generation (MWh) in Alberta

The following power generation forecast assumptions were used:

- Generation capacity is expected to increase to 17,000 MW by 2020 and to 20,500 MW by 2029. This will include large and small capacity generation additions. Capacity changes are expected to include the following mix of technologies:
    - **Coal-fired generation:** The currently proposed federal coal regulations, as outlined in Section 2.4.2, require that units will retire at 45 years of age. By 2025, about 52% of coal generating units would have retired under the proposed regulation. The coal-fired unit capacity factor will continue at the same rate as in 2000–2011;
    - **Clean coal technologies:** are expected to become commercially available after 2020, as a result of extensive research and development funding worldwide, creating an option for developing Alberta's abundant coal resources;
    - **Natural gas**: Gas-fired generation currently is one of the lowest cost options per megawatt of installed new capacity and expansion of this technology is expected to continue, if gas supply and prices remain reasonable;

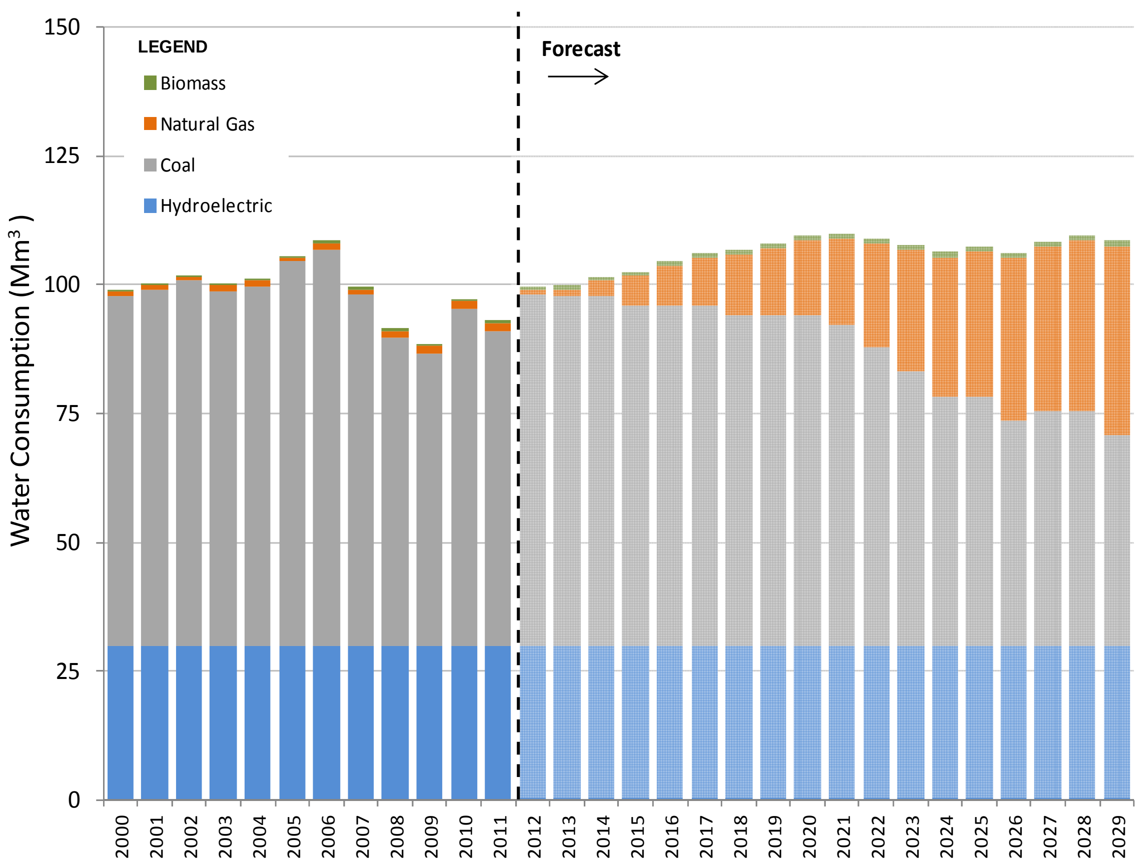
  - **Co-generation:** Alberta's expanding industrial sector's increased need for steam and heat makes highly efficient co-generation an option for future growth. The industry as a whole is expected to continue to increase co-generation capacity, as it has in the past;
  - **Wind:** Assumed to reach a total installed capacity of 2,500 MW in Alberta by 2020; and
  - **Hydro/Nuclear:** Potential may exist for hydro and nuclear developments; however, these were not included in the forecast.
  - A total of 290 MW of capacity of 'other renewables' and 'new technology' is included prior to 2020, and an additional 700 MW post-2020.
- Capacity factors (actual generation divided by nameplate generating capacity) for coal and wind were assumed to be 84% and 33% respectively, based on the average from 2000 to 2011;
- Simple cycle gas turbines, biomass, and imports were assumed to be a constant portion of total generation at 1, 1 and 3%, respectively, based on the average from 2000 to 2011;
- Co-generation from the grid was assumed to be a constant 11% of total generation, based on rates from 2009 to 2011; and
- Co-generation from "behind-the-fence" (i.e. embedded within a host industrial facility and providing only surplus electrical power to the Alberta electricity grid) was assumed to be a constant 18% of total generation, based on rates from 2009 to 2011.

The result of the above assumptions is the growth of all generation types except for coal. In particular, natural gas technologies provide for the bulk of the growth in electricity demand, as shown in Figure 11.

Water Consumption Forecast

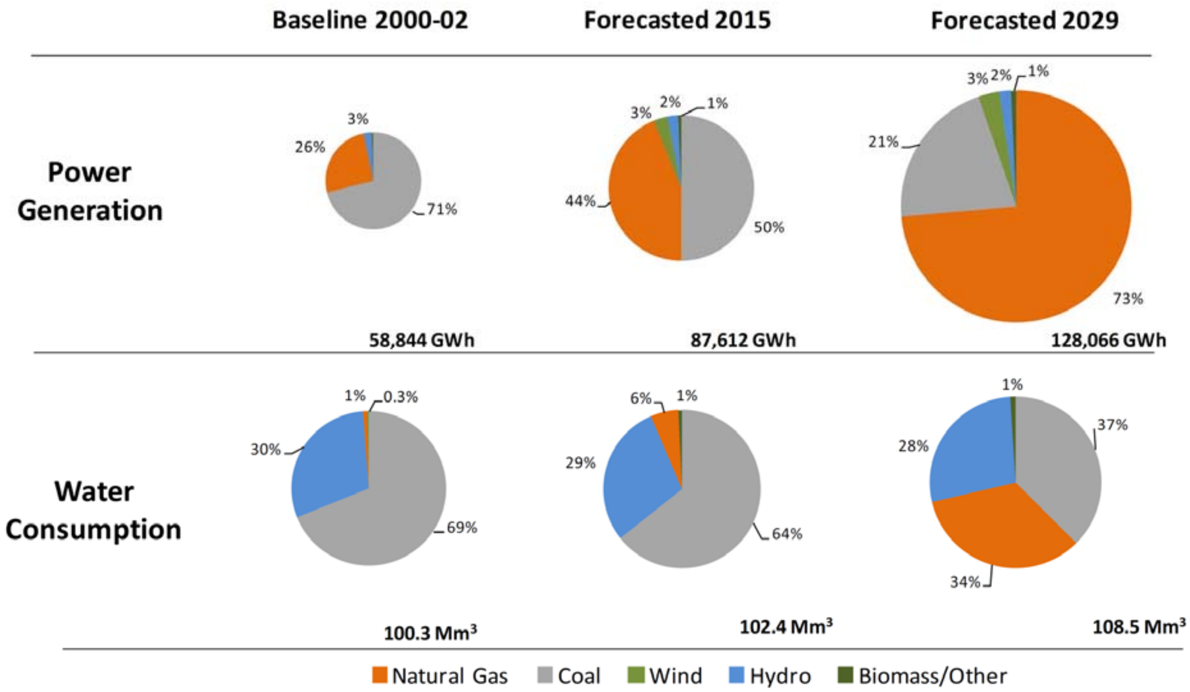
The water consumption forecast is based on the forecast power generation. Water consumption for the Alberta power generation sector is expected to increase slightly from about 100 Mm^3 during baseline years to 102 Mm^3 by 2015 and to 108.5 Mm^3 by 2029; these slight increases in overall water consumption across the sector are expected despite a significant predicted increase in total generating capacity in the province to meet rising electricity demand. The water consumption forecast is shown on Figure 12. The forecast assumes constant unit rates of water consumption and does not account for potential changes to local climate that occur from year to year. The forecast does not include potential future water efficiency improvements at individual plants (a potential water saving) and does not include potential increased water consumption requirements due to proposed air quality regulations.

The water consumption estimate is illustrated in Figures 12 and 13, in comparison with the changes in the generation mix and energy production. Water requirements for coal-fired facilities will likely decrease as many coal plants are expected to retire within the next twenty years and be replaced with relatively water-efficient types of generation, such as combined cycle gas plants.



Source: AESO Annual Net Generation Data (2011), ERCB Data (2011), AESO Future Demand and Energy Outlook (2009-2029), ETIPRG (2010) Water Consumption Rates

Figure 12: Forecasted Water Consumption (Mm^3) for the Power Sector in Alberta



Source: AESO Annual Net Generation (MWh) Data (AESO, 2011), ERCB Data (2011), AESO Future Demand and Energy Outlook (2009-2029), ETIPRG (2010) Water Consumption Rates

Figure 13: Breakdown of Forecasted Water Consumption (Mm^3) by Generation Type in Alberta

3.2 CEP Performance

Selected water productivity measures

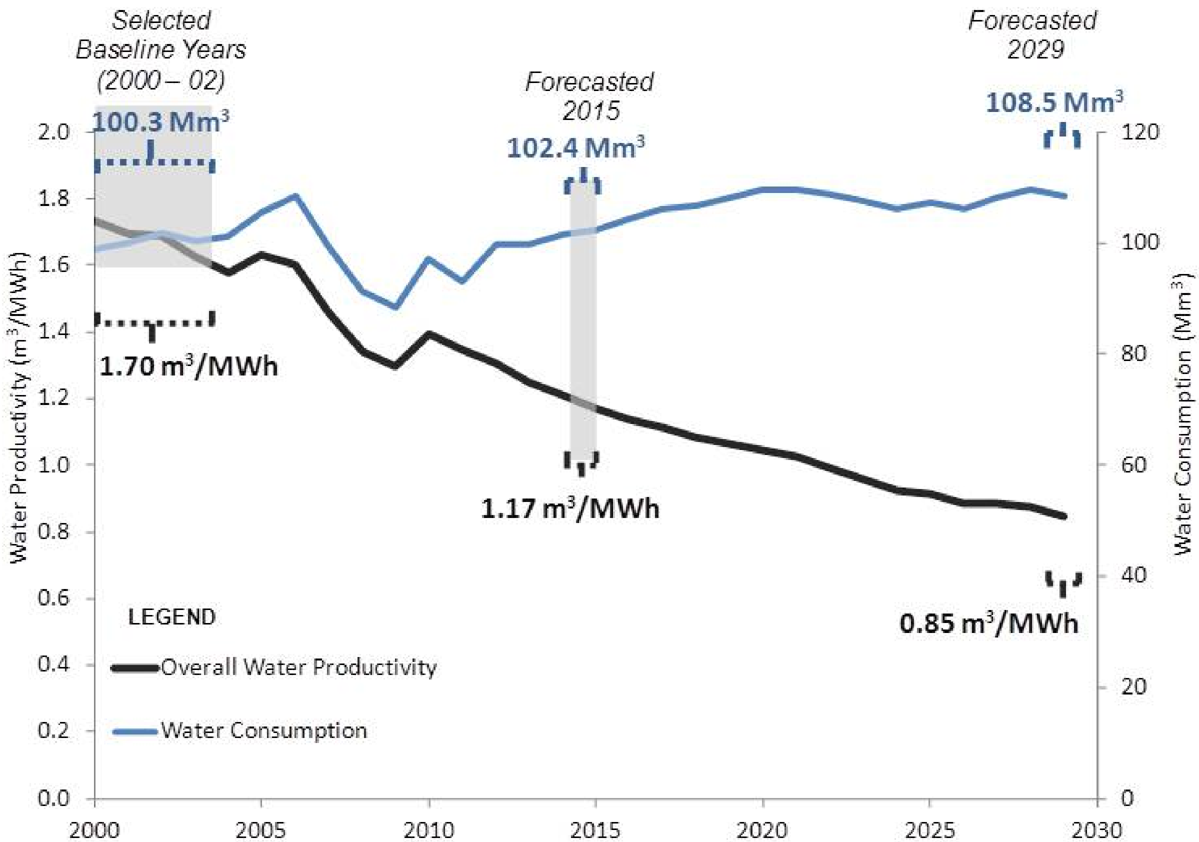
CEP performance is reported as the projected water use productivity in 2015 compared to historical baseline years.

The selected "water productivity" performance measure is defined as the volume of water consumed per megawatt hour (MWh) of energy produced. This measure accounts for potential water efficiencies or conservation, reflecting improvements even though Alberta energy demand is expected to increase. Similarly, the "equivalent water conservation" was selected as a measure to indicate the relative water savings assuming no change in the energy demand. This measure is indicative of the water use improvements masked by the significant growth in electricity demand.

Projected water productivity improvements

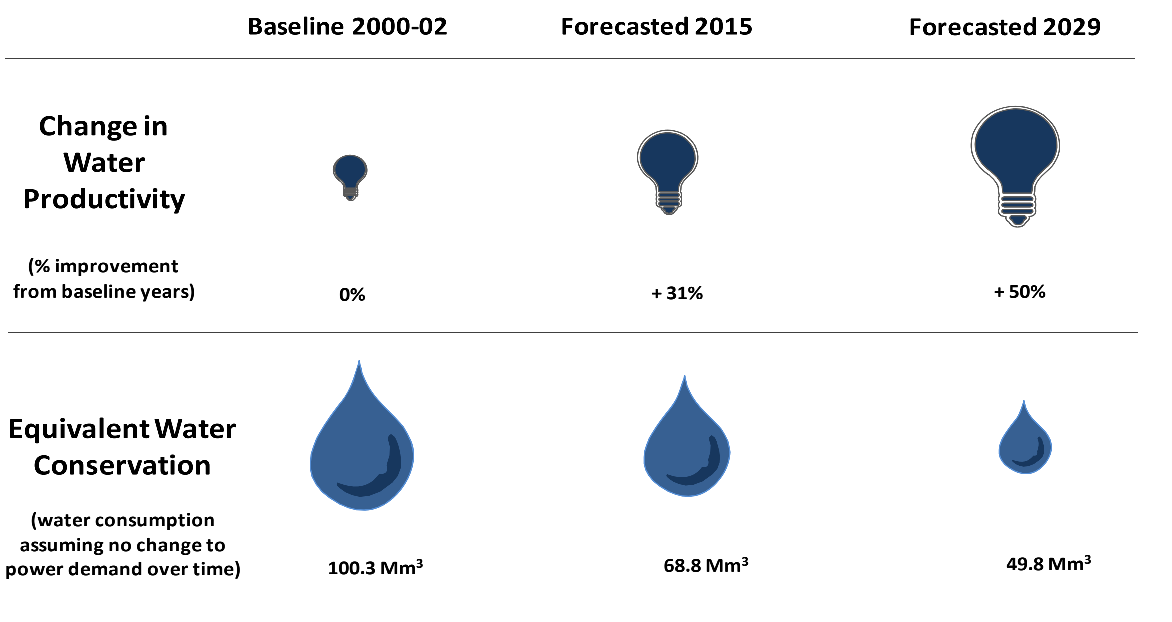
Compared to baseline conditions, the sector expects to improve water productivity by 31% by 2015, and by 50% by 2029. During the baseline period from 2000–2002, a net water consumption of 1.7 m^3 was required for each MWh of power generated, or about 100 Mm^3 across the sector for about 59,000 GWh of power generated. As the power generation mix changes this overall water productivity is projected to improve to 1.17 m^3/MWh in 2015 and to 0.85 m^3/MWh in 2029. Actual productivity is a function of many factors and will vary in wet or dry years, with changes in temperature, facility dispatch, etc. The projected water productivity

(m^3/MWh) and total water consumption (Mm^3) are shown on Figure 14 and Figure 15, including an estimate of equivalent water conservation if the energy demand did not change (50%).



Sources: AESO Annual Net Generation (MWh) Data (AESO, 2011), ERCB Data (2011), AESO Future Demand and Energy Outlook (2009-2029), ETIPRG (2010)

Figure14: Summary of Forecasted Water Consumption (Mm^3) and Productivity (m^3/MWh)



Sources: AESO Annual Net Generation (MWh) Data (AESO, 2011), ERCB Data (2011), AESO Future Demand and Energy Outlook (2009-2029), ETIPRG (2010)

Figure 15: Summary of Expected Improvements for Water Productivity (m^3/MWh) and Equivalent Water Conservation (Mm^3)

4 Overview of Opportunities for CEP

4.1 Identification of CEP Opportunities

The power generation sector has the potential to improve water CEP by reducing water consumption or by increasing power generated with the same amount of water. Opportunities were identified and evaluated in a qualitative manner based on industry interpretation of the potential CEP value. The viability of CEP opportunities depends on the site-specific details of each project as they relate to each individual site.

The CEP opportunities identified by ATCO Power, Capital Power Corporation and TransAlta are listed in Table 2. Many of these potential opportunities are already being implemented by some producers.

4.2 Analysis of CEP Opportunities

Target Improvements

The broad improvement objective for *Water for Life* was to voluntarily improve water productivity for the combination of all sectors by approximately 30% by 2015 as compared to the baseline in the period of 2000 to 2005. This same value was used to provide an indicative target for the electric power sector.

Priorities

The CEP opportunities were assessed based on the following priorities:

- Net environmental benefits – opportunities with concurrent net environmental benefits; and
- Implementation availability – opportunities that are proven and readily available for implementation.
- Maintaining a reliable, economic supply of power for Alberta;

CEP Challenges

There are several CEP challenges that exist in the power generation sector. Electric power generation is largely influenced by external factors such as electricity demand, economic conditions, environmental conditions and regulations. Key challenges are described below:

- Electricity Demand - the magnitude, location and time (daily and seasonal fluctuations) of electricity demand can affect power generation options and choices.
- Economic Conditions - commodity prices and market dynamics (e.g. gas price, location) can influence the future generation mix and operations with a corresponding effect on water consumption.
- Regulations - regulation of one environmental aspect area may impact other aspects. For instance, regulations to reduce air emissions may result in the installation of control technology that requires the use of water (i.e. carbon capture).
- Environmental Conditions - actual productivity will vary in wet or dry years because of the large dependency on climate and cooling processes for thermal power.

4.3 CEP Opportunities

The Plan recognizes a number of opportunities, the applicability of which varies between specific operations and types of development. A decision to implement any of the opportunities in the Plan must be informed by a project-specific assessment of potential tradeoffs.

Overall, the following opportunities are considered to provide the most significant CEP gains as shown in Table 2:

- Consider generation technologies with lower water consumption as generation is added to address increased energy demand or as aging facilities retire over next 20 years;
- Continue to evaluate process improvements at individual facilities, such as water treatment improvements and water reuse;
- Upgrades to transmission infrastructure to reduce electricity transmission losses and support increase in competitive distributed generation opportunities;
- Improved availability and completeness of water diversion, consumption and return flow information available from AESRD from all sources; and
- Encourage energy conservation and efficiency measures by others, as a means of reducing the overall energy demand (e.g. residential energy conservation and time-of-day usage patterns).

The power sector is facing significant regulatory uncertainty with respect to the control of GHG and other air emissions. Proposed regulations may result in emissions technologies that impact water use. Most of the current control technologies tend to increase water consumption, such as scrubbers. They also tend to increase the parasitic load, (i.e. internal demand for electricity to power the emissions control technology), resulting in less efficient power generation.

Table 2: Potential CEP Opportunities

ID	Potential Opportunity	Comments	Currently Implemented Examples
1	Continue to consider implementing other higher efficiency forms of generation and co-generation (gas- or biomass-fired) where possible to utilize waste heat for other industries.	***Benefits:*** Overall water consumption across the sector may decrease as large industrial operations (e.g. oil sands operations) generate electricity for their own demands. Water is being used efficiently by multiple industrial processes (e.g. refining, heat, and power generation). ***Challenges:*** Power generation water use reporting can be challenging, because the water use is generally reported under a larger license for the entire industrial operation.	• Joffre Co-generation Facility (416 MW capacity) near Red Deer is part of the NOVA Chemicals Corporation petrochemical facility and generates electricity and steam / heat required to operate the petrochemical facility. • Mildred Lake Co-generation Plant (265 MW capacity) is part of Syncrude's Mildred Lake facility, located 40 km north of Fort McMurray. This plant provides necessary electric and thermal energy to the Syncrude Project. • Scotford Cogeneration Plant (170 MW capacity), constructed at the Shell Scotford Refinery Site east of Fort Saskatchewan, Alberta, provides steam and electricity to meet the thermal and power needs of the Athabasca Oilsands Upgrader. The Upgrader utilizes two-thirds of the electricity generated with the balance being sold to the Alberta grid.
2	Retire higher water consumption generation technologies (e.g. coal) as they reach the end of their design life.	***Benefits:*** Retirement of conventional coal-fired units will tend to decrease the power sector's water diversion and consumption volume if the energy load is shifted to generation with relatively low water requirements. ***Challenges:*** Proposed coal regulations limit the life-span of coal fired units to 45 years. Must develop necessary capital to replace them in a timely manner with alternative technologies. Not all viable alternatives have low water requirements	• Shutdown of Wabamun plant in the past 5 years, which used one-through cooling system, has reduced the water diversion volume.

3	Select lower water intensity generation technologies as a replacement for retirement of higher water intensity generation technologies.	***Benefits:*** Water conservation by reducing the power sector's water diversion and consumption intensity. ***Challenges:*** Future reliance on natural gas generation technologies is strongly dependent on fuel prices and market conditions (e.g. co-generation is dependent on industry). Not all viable alternatives have low water requirements	• Combined cycle generation is currently expected to replace most of the retiring coal-fired units.
4	Continue to evaluate water efficiencies at specific facilities.	***Benefits:*** Improved water efficiency and quality of return water. ***Challenges:*** Some water saving measures may reduce the power generation capacity (i.e. reduced water consumption may decrease cooling process efficiencies and decrease power generation). Upgrades to existing older plants may not be economic if the plants are due to retire soon.	• General examples: water recycling, cooling tower cycle optimization, use of cooling ponds. • Many of the coal-fired units in Alberta have been upgraded to produce more power without increasing fuel or water diversion or consumption. • Minimizing Genesee water treatment for boiler process water through efficiencies in water chemistry/water treatment. An example is process water treatment resin change-outs, which increase the efficiency of the purification process in the water treatment plant, and minimizes the use of water and chemicals to regenerate resins. • Conversion of Clover Bar natural gas boilers to aero-derivative natural gas turbines reducing the amount of consumed water for cooling. • New coal-fired plants (Keephills 3 and Genesee 3) have implemented the latest technology which reduces water consumption intensity. • Management of water releases from cooling ponds often reduces the TDS loading to receiving rivers at coal plants, minimizing impacts of return flow on the receiving water body.

5	Improve the current cooling processes (without changing the amount of water diverted) at existing facilities to minimize water consumption due to evaporation (e.g. altering water chemistry, more efficient cooling mechanisms and technologies).	***Benefits:*** Decrease overall water consumption, increase water conservation. ***Challenges:*** Upgrades to older plants may not be cost-feasible, if the plants are due to retire soon.	• At Joffre, polymers, dispersants and phosphates used in the cooling tower have been altered, allowing operators to increase cycling of water through the cooling tower. This decreases water consumption per MWh produced, and also reduces the overall waste stream volume.
6	Consider upgrades for transmission infrastructure to improve the overall efficiency of the electricity grid throughout Alberta.	***Benefits:*** Upgrades to the Alberta transmission infrastructure would reduce transmission losses by shortening transmission distances. As a result, new power generation facility sitting and design can consider synergies with other industries (e.g. biomass power plants located in the northern portion of the province can deliver power to the more populated south-central portions of the province). Flexibility to select locations based on tradeoffs (e.g. between water availability and assimilative capacity for emissions). ***Challenges:*** Transmission upgrades may result in additional environmental footprint	• Currently being assessed in AESO Long-term Transmission Plan (AESO, 2009b).
7	Improve availability and completeness of water diversion, consumption and return flow data available from AESRD from all sources.	***Benefits:*** Water use reporting will help with estimates for water consumption and assessment of improvements. ***Challenges:*** Difficulty remains for identifying all water licenses tied to power generation sector. For some facilities (i.e. co-generation), licenses for water use are often held by other parties. In these cases reasonable approximations of water use by process may not be available.	• Individual power facilities that operate under a water license (e.g. Sheerness, Keephills, etc.) annually report to AESRD for water use database.

8	Demand management for energy	***Benefits:*** Energy demand management would reduce the requirements for energy production and corresponding water use. ***Challenges:*** Potential savings is largely dependent on consumer use patterns.	• Ongoing measures and programs have been implemented to reduce power use and increase power efficiency (e.g. Alberta Energy Efficiency Alliance).
9	Consider alternative water sources for cooling processes and general facility water use.	***Benefits:*** Treating and reusing wastewater within the cooling processes that would otherwise be released back into the environment could reduce water diversion and reduce impacts on the environment. *Challenges:* Increase in expenses to treat and reuse wastewater to a high quality and potential increase in water use with increased quantity of waste water treated. Difficult and expensive to retro-fit existing plants	
10	Consider water consumption when reviewing air emission control technologies to comply with proposed air emissions regulations	***Benefits:*** Considering water consumption at the beginning of a project will result in the lowest water consumption in the long-term ***Challenges:*** Some scrubber technologies could increase the amount of water consumed to meet potentially stricter air emission targets. Legislation (e.g. BLIERs) requirements for air emission targets are unclear and unknown. Upgrades to older plants to include lower water consumption scrubbers may not be cost-effective. Not all viable alternatives have low water requirements.	• A number of the natural gas-fired plants in Alberta are designed to use dry NOx controls thus reducing water consumption as compared to damp NOx control systems.

Sheerness Thermal Generating Facility

Recreation Park on Sheerness Thermal Generating Facility Cooling Pond

5 CEP Plan Implementation, Monitoring and Participation

5.1 Implementation and Schedule

The implementation of this CEP for the power generation sector will include the following:

- Consider replacing retiring facilities with generation technologies that have lower water consumption rates, such as natural gas-fired turbines.
- Consider potential opportunities where possible on an on-going basis.
- Utilize the developed water productivity measures for future tracking of sector CEP progress and when the CEP is updated.
- Encourage AESRD to improve availability and completeness of water diversion, consumption and return flow information submitted to AESRD from all sources to improve estimates of actual water consumption and use
- Promote a balanced assessment of tradeoffs between conflicting environmental objectives for air, water and land as part of the planning process for proposed projects.

Additional Plan initiatives may be considered depending on the results of proposed federal GHG and air emission regulations and requirements, as well as other impacting factors such as load growth and economics.

A schedule is not proposed for opportunities that are the responsibility of others, such as improved water use reporting by the Alberta government, and residential energy efficiency programs for power demand management.

5.2 Integration with Other Plans

The CEP Plan for the power sector should be integrated with other initiatives such as:

- Regional development and environmental protection plans;
- Provincial energy plan; and
- Federal and provincial GHG and air emission control regulations.

These other plans may offset some of the potential water CEP opportunities, due to tradeoffs with other objectives – federal GHG and air emission control regulations, in particular, may result in additional water use to reduce emissions to the atmosphere.

5.3 Monitoring and Reporting

The developed metrics are available for use by the electric power sector and can be used for future Alberta Water Council initiatives as is, or updated should new information become available.

5.4 Participation and Accountability

The sector will continue to comply with water use regulations and will continue to pursue improvements in water CEP.

6 Summary

This Electric Power Generation Sector CEP Plan is intended to provide an initial road map for industry to document existing water use, expected future water use, and opportunities to further improve water use, as envisioned by Alberta's *Water for Life* strategy.

The electric power generation sector has a long history of careful management of water use, implementing new technologies and operating practices when appropriate. The sector will continue to investigate technologies to improve environmental performance, including water use and will continue its collective commitment to meet regulatory water use requirements.

Future water requirements for electricity generation may be influenced by proposed air emissions regulations and other environmental initiatives; legislation to achieve one environmental objective may impact another objective (e.g. air emission controls may increase water consumption).

Compared to baseline (2000-2002) annual water consumption of about 100 Mm^3, the sector expects to consume about 102 Mm^3 per year of water by 2015 and 108.5 Mm^3 by 2029 (2% increase by 2015, 7% increase by 2029). Over the same periods, power generation is expected to increase by 50% and 100% respectively.

The selected performance measure for documenting water CEP improvements is water productivity. Water productivity is defined as the volume of water consumption (i.e. water diversion minus return flow) per unit of energy production. The CEP improvements are measured from the selected baseline years of 2000–2002 as compared to forecast conditions in 2015. Water productivity improvements are expected to be 31% by 2015; and 50% by 2029.

Information used to develop this CEP plan is publicly available. Table 3 provides a summary of the objectives and outcomes of this CEP Plan.

Table 3: CEP Comparison to Criteria for Review

CEP Objectives	CEP Report Outcomes
Results in continuous CEP improvements	Identifies opportunities that will lead to improvements in conservation, efficiency, and productivity
Identifies benchmarks and measurable CEP targets for water productivity	Identifies a metric and a current benchmark
Review and analysis of potential CEP opportunities and selection of those which will achieve CEP improvements	Current implemented opportunities identified in addition to potential opportunities relating to conservation, efficiency, and productivity
Outlines process to involve stakeholders and address stakeholder interests	Focus on collection of information to enable additional discussion with interested parties
Describes how sector CEP activities will be monitored and evaluated to measure CEP improvements	Developed indicative metrics can be used as required, until sufficient actual data and information I available to update methodology
Describes the sector's process for ongoing reporting objectives and performance measures for the sector	Use reporting programs in place to update and communicate progress
Outlines an implementation schedule	Implementation is on-going with operational and development places, benchmarks and metrics updates as required
Follows the recommended annotated Table of Contents	Plan generally follows annotated Table of Contents

7 Glossary and Acronyms

AESRD – Alberta Environment and Sustainable Resource Development

AESO – Alberta Electric System Operator

AIES – Alberta "Interconnected Electric System" as that term is defined in the *Electric Utilities Act* in Alberta

AUC – Alberta Utilities Commission

AWRI – Alberta Water Research Institute

BATEA – Best Available Technology, Economically Achievable

BLIER – Base Line Industrial Emission Regulations

Blowdown – removal of liquids or solids from a process

CASA – Clean Air Strategic Alliance

Capacity – the rated continuous load-carrying ability, expressed in megawatts (MW) of generation, transmission, or other electrical equipment

Capacity factor – ratio of the actual output of a power plant over time (generation, MWh) and its potential output if it had operate at its full capacity the entire time.

CEP – conservation, efficiency and productivity

CO_2 – carbon dioxide

Co-generation – a generating facility that produces electricity and another form of useful thermal energy (such as heat or steam); used for heating or cooling purposes, industrially and commercially

Combined cycle – an electric generating technology in which process steam and electricity are produced from otherwise lost waste heat exiting from one or more combustion turbines; the exiting heat is routed to a conventional boiler or to a heat recovery steam generator for use by a steam turbine in the production of electricity which increases the efficiency of the electric generating process.

Conservation – Any beneficial reduction in water use, loss or waste, or practices that improve the use of water to benefit people or the environment

DFO –Fisheries and Oceans Canada

Efficiency – the accomplishment of a function, task, process or result with the minimal amount of water feasible; an indicator of the relationship between the amount of water required for a particular purpose and the quantity of water used or diverted

EPEA – *Environmental Protection and Enhancement Act*

GHG – greenhouse gas

Makeup water – additional water required for a process to makeup for losses such as blowdown or evaporation

n/a – not available
MW – Megawatt, unit of capacity, defined as an amount of derived energy per second, measures the rate of energy conversion or transfer.

MWh – Megawatt hours, unit of generation. The megawatt-hour is a unit of energy equivalent to one megawatt (1000 kW) of power expended for one hour (1 h) of time.

NSR – North Saskatchewan River

Parasitic load – the energy required to generate electricity, resulting in a net energy distribution that is less than the gross production.

Peaking – plants that run for short periods when the energy demand and consequently the market price is high; typically capacity factors have been below 50% and the cost of fuel has been relatively high.

Produced water – water that is produced and released or disposed as a result of oil and gas activity

Productivity – the amount of non-saline water required to produce a unit of any good, service, or societal value

Return flow – water that is included in an allocation and is expected to be returned to a water body after use and may be available for reuse, although the water quality characteristics may have changed during use

SSRB – South Saskatchewan River Basin

Stakeholders or Interested Parties – people with an interest in the effects of industrial activities; may include nearby landowners, municipalities, Aboriginal communities, recreational land users, other industries, environmental groups, governments and regulators

Surface water – water located above ground (e.g. rivers, lakes, wetlands)

TDS – total dissolved solids

Water allocation – the amount of water that can be diverted for use, as set out in water licenses and registrations issued in accordance with the *Water Act*

Water diversion (or withdrawal) – the amount of water removed from a surface or groundwater source, either permanently or temporarily

Water evaporation – the amount of water that is evaporated in a cooling process, such as a cooling tower. Evaporated water is a consumptive use that is returned to the environment as moisture in the air, rather than being returned as water to the original source of the water diversion.

Water recycle – using water multiple times for similar purposes

Water reuse – using water that has already been used for one purpose, such as produced water from a gas or oil well, one or more additional times for other purposes

Water-short – a region of watershed that is potentially short of water, with a relatively high volume of water allocation compared to the actual water volume from stream flow

Water use – net water use or the difference between the amount of water diversion and the return flow; for the purpose of the CEP Plan, return flows have been neglected, so the water use described in this report is equivalent to the water diversion

Withdrawal – a volume of water removed under license from a water source

WPAC – Watershed Planning and Advisory Council

8 References

Information and data used to prepare this document came from many sources. All the following information is available through public sources:

Alberta Electric System Operator (AESO). 2009a. AESO *Future Demand and Energy Outlook (2009 – 2029).* Calgary, Alberta

Alberta Electric System Operator (AESO). 2009b. *AESO Long-term Transmission System Plan.* Calgary, Alberta.

Alberta Electric System Operator (AESO). 2011. AESO Market Statistic Data 2000 to 2011: Market System and Reporting. Last accessed on June 13, 2012 at <http://www.aeso.ca/market/8856.html> .

Alberta Electric System Operator (AESO). 2011. Annual Net Generation Data (2000–2011 power generation).

Alberta Environment. 2003a. *Water for Life: Alberta's Strategy for Sustainability.*

Alberta Environment. 2006a. *Water-short Areas Assessment.*

Alberta Environment. 2006b. *Approved Water Management Plan for the South Saskatchewan River Basin*.

Alberta Environment. 2006c. *Cold Lake-Beaver River Basin Water Management Plan.*

Alberta Environment. 2006d. *Water Conservation and Allocation Policy for Oilfield Injection.*

Alberta Environment. 2008a. *Land-use Framework*.

Alberta Environment. 2008b. *Water for Life: A Renewal.*

Alberta Environment. 2009a. *Water Management Framework for the Industrial Heartland and Capital Region.*

Alberta Environment and Department of Fisheries and Oceans. 2007. *Athabasca River Water Management Framework.*

Alberta Research Council. 2008. *Annual Report 2007-2008.*

Alberta Water Council. 2006. *Water Conservation, Efficiency and Productivity (CEP) Definitions Project Team – Interim Report.*

Alberta Water Council. 2008. *Recommendations for Water Conservation, Efficiency and Productivity Sector Planning.*

Clean Air Strategic Alliance (CASA). 2007. *The Comprehensive Air Quality Management System: CASA's Decision Making Process*. Edmonton, AB. ISBN 978-1-896250-55-7.

Electric Power Research Institute (EPRI). 2002. *Water & Sustainability (Volume 3): U.S. Water Consumption for Power Production—The Next Half Century*. Palo Alto, CA. 1006786.

Electric Power Research Institute (EPRI). 2007. *Program on Technology Innovation: An Energy/Water Sustainability Research Program for the Electric Power Industry*. Palo Alto, CA. 1015371.

Energy Resources Conservation Board (ERCB). 2011. *ST98-2011 Alberta's Energy Reserves 2010 and Supply/Demand Outlook 2011-2020*.Calgary, Alberta. 1910-4235.

Energy Technology Innovation Policy Research Group (ETIPRG). 2010. *Water Consumption of Energy Resource Extraction, Processing, and Conversion, A review of the literature for estimates of water intensity of energy-resource extraction, processing to fuels, and conversion to electricity*. Energy Technology Innovation Policy Discussion Paper No. 2010-15, Belfer Center for Science and International Affairs, Harvard Kennedy School, Harvard University

Environment Canada. 2012. National Climate Data and Information Archive: Canadian Climate Normals or Averages 1971-2000. Last accessed on May 29, 2012 at <http://www.climate.weatheroffice.gc.ca/climate_normals/index_e.html>

Gleick, P.H. 1994. *Water and Energy in Annual Reviews, Annual Rev*iew. Energy Environment., 1994, 19:267-99.

Golder Associates Ltd. 2008. *Water Supply Assessment for Alberta*. Prepared for Alberta Environment.

Golder Associates Ltd. 2010. *Hydro-Climate Modelling of Alberta South Saskatchewan Regional Planning Area*. Prepared for Alberta Environment – Environmental Modelling.

Government of Alberta – Energy. 2008. Launching Alberta's Energy Future, Provincial Energy Strategy. ISBN 978-0-7785-6332-7.

Government of Alberta. 2009. *South Saskatchewan Region – Water Allocation Transfers*. Facts at your fingertips.

Health Canada. 1978. *Total Dissolved Solids (TDS).* http://www.hc-sc.gc.ca/ewh-semt/pubs/water-eau/tds-mdt/index-eng.php

National Energy Technology Laboratory (NETL). 2009. *Water Requirements for Existing and Emerging Thermoelectric Plant Technologies*. Pittsburgh, PA . DOE/NETL-402/080108.

National Energy Technology Laboratory (NETL). 2011. *Estimating Freshwater Needs to Meet Future Thermoelectric Generation Requirements*. Pittsburgh, PA . DOE/NETL-2011/1523.

National Renewable Energy Laboratory (NREL). 2003. *Consumptive Water Use for U.S. Power Production*. Golden, Colorado. NREL/TP-550-33905.

United States Department of Energy (USDOE). 2006. *Report to Congress on the Interdependency of Energy and Water*. Washington D.C.

Virginia Water Resources Research Center. 2008. *The Water Cooler – The Intertwined Tale of Energy and Water*. Last accessed May 23, 2012. <http://vwrrc.vt.edu/watercooler/watercooler_apr08.html>

Appendix A

Description of Power Generation Types

Coal-fired Power Plants

Description

Coal-fired power plants have been an important basis for electric power generation in Alberta for many years. In simple terms, in a conventional coal-fired power plant, coal is burned in a boiler to produce steam, which is used to turn a steam turbine which drives an electric generator. The basic design of conventional coal-fired power plants is similar to boiler-based power generating units that use a variety of fuels - basically anything that burns can be used as a fuel. Burning coal produces ash which must be removed as it accumulates; and also exhaust gas which must be filtered for any dust, ash and other contaminants before it is released (EDF, 2012a).

Some basic features of conventional coal power plants (adapted from Crawley, n.d.; AESO, 2009) are:

- Efficiency of about 35 to 40% in converting fuel to electricity;
- Large base-load coal plants are typically operational between 80%–90% of the year (Archer and Jacobson, 2007);
- Coal-fired power plants are slow to start or to change output while operating.

A schematic of a conventional coal-fired plant is shown in Figure A-1. As the coal is burned, water is heated in pipes coiled around the boiler, turning it into steam. The hot steam expands in the pipes, so when it emerges it is under high pressure (EDF, 2012a). The pressure drives the steam over the blades of the steam turbine, causing it to spin, converting the heat energy released in the boiler into mechanical energy. As the steam turbine spins, a shaft which connects the turbine to the generator spins the generator and electricity is produced (EDF, 2012a).

After passing through the turbine, the steam is condensed and used again (EDF, 2012a). There are several different condensing cooling mechanisms available and these are described in Appendix C. Once the steam is condensed, it is piped back to the boiler, and the cycle repeats.

One more advanced form of coal-fired power plant is an integrated gasification combined cycle (IGCC) power plant (NEB, 2008). IGCC is considered an emerging technology, and currently there are no IGCC plants in operation or planned for Alberta. An IGCC power plant uses a partial combustion process that converts coal into syngas: a mixture of carbon monoxide and hydrogen (NEB, 2008). This syngas fires the combustion turbine in a combined-cycle power plant. Along with improved efficiency in power production, the benefits of IGCC include the ability to scrub pollutants like sulphur and heavy metals from the fuel before it is burned (NEB, 2008).

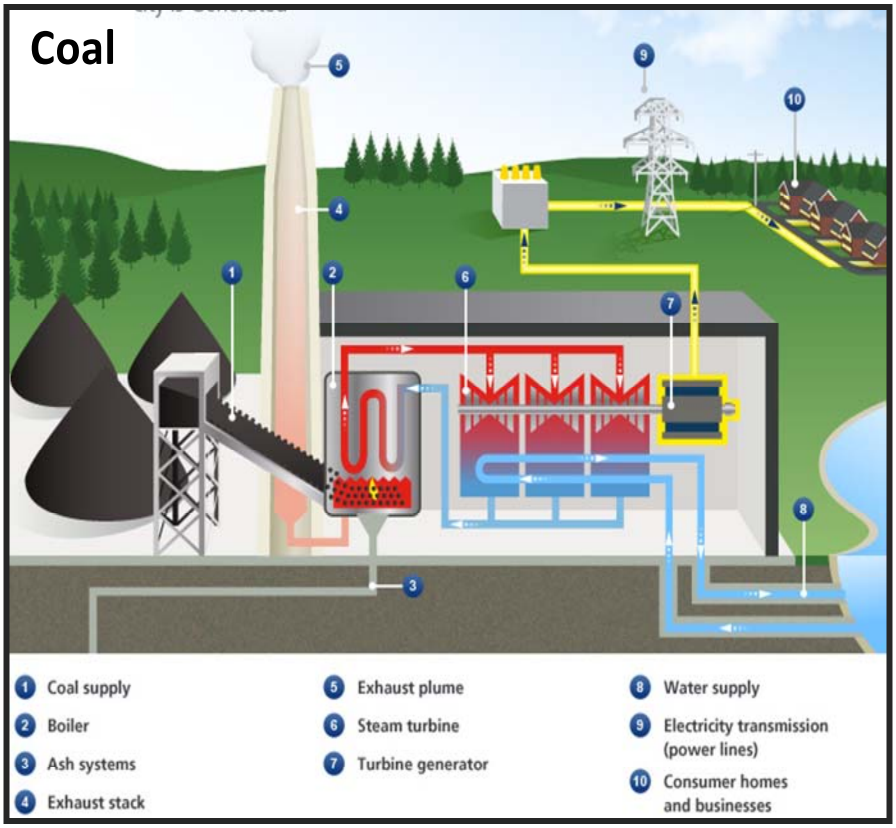


Figure A-1: Schematic of a Typical Conventional Coal-Fired Power Plant (EDF, 2012a)

Water Use

Cooling water for condensing exhaust steam from steam turbines is the largest use of water in a conventional coal-fired power plant. For plants with wet cooling systems, the cooling tower make-up represents approximately 95% of the total power plant water requirements (Maulbetsch and DiFilippo, 2006). A large portion of this water is returned to the source. Smaller amounts of water are used consumptively for boiler feed and other process uses. At some plants, some water is consumed by scrubbers for air emissions (e.g. NOx, SOx control) to meet air quality requirements (Maulbetsch and DiFilippo, 2006). These scrubbers create wastewater which must be treated before release.

A number of alternative cooling systems exist and have been used. A discussion and comparison of these cooling systems are provided in Appendix B.

Natural Gas - Simple Cycle Power Plant

Description

A simple cycle gas turbine power plant uses only combustion turbines and generally does not utilize waste heat recovery, resulting in lower thermal efficiency.

Basic features of a simple cycle power plant are listed below (adapted from (Crawley, n.d.; AESO, 2009):

- Simple cycle power plants are about 40% efficient;
- Start up time to full load is quite fast, approximately 10- 20 minutes;
- They are typically used on an intermittent basis to meet the highest (peak) electricity demands, for example very hot summer afternoons, often less than 10% of the time;

Typically the gas turbines used for simple cycle systems are similar to jet aircraft engines; and for comparison a 30 MW simple cycle power plant is equivalent to an engine of a Boeing 737 (Crawley, n.d.). Natural gas is burned in combustors in the presence of compressed air, producing a high temperature and high pressure gas which drives the turbine (CASA, 2004). As the shaft of the turbine spins, a coupled generator produces electricity. A schematic of a typical simple cycle power plant is shown in Figure A-2.

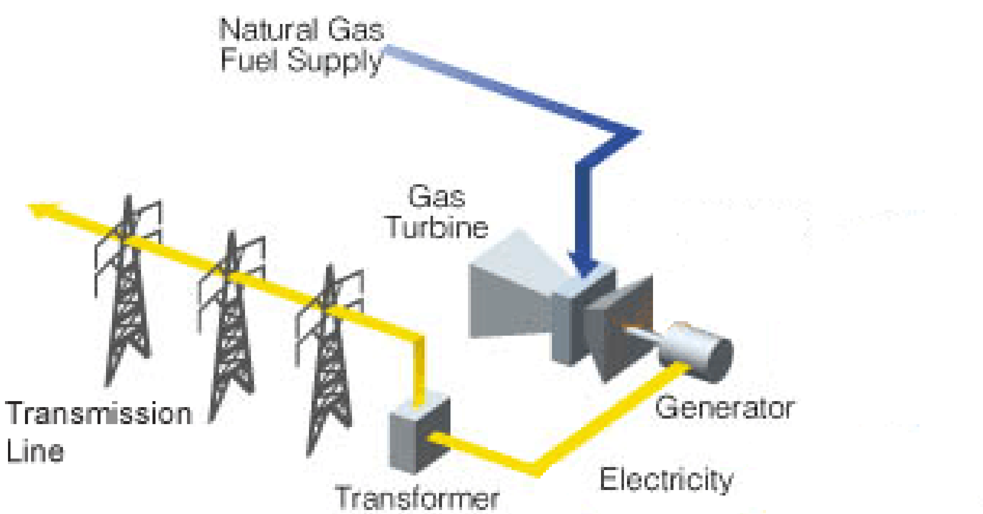


Figure A-2: Schematic of a Typical Simple Cycle Gas Power Plant (CASA, 2004)

Water Use

These power plants only use combustion turbines to generate power and do not require any cooling water, which greatly reduces the amount of water consumption required for operation. Water is used for basic plant operations (e.g. water used for equipment cleaning, drinking, sanitary uses). At some plants, water is consumed for turbine inlet air cooling and control of air emissions (e.g. NOx, SOx control) to meet air quality requirements (Maulbetsch and DiFilippo, 2006). These scrubbers create wastewater which must be treated before release.

Natural Gas – Combined Cycle Power Plants

Description

A combined cycle power plant is an electrical power plant in which a natural gas-fired combustion turbine and a steam turbine are used in combination to achieve greater efficiency than would be possible independently.

Some of the basic features of a combined cycle power plant are listed below (adapted from Crawley, n.d.; AESO, 2009):

- Overall efficiency of converting fuel to electricity is greater than 50%. Power output of the steam turbine is about 1/3 of the total output of the total power output of the combine cycle power plant. The "extra" electricity produced from the same amount of turbine energy (without additional fuel consumption) makes a combined cycle plant much more efficient than a simple cycle gas turbine peaking plant;
- The steam portion of combined cycle plants takes approximately 1.5 to 3 hours to heat up, although newer technologies are improving upon this.;
- Combined cycle facilities can be designed to operate as peaking or baseload facilities, although most operate mid to base loaded, rather than as peaking facilities.

Each combined cycle power-generating unit consists of a gas combustion turbine, a HRSG, a steam turbine and generators. The gas turbine drives electrical generators while the gas turbine exhaust is used to produce steam in a heat exchanger or HRSG to supply steam turbines whose output provides the means to generate more electricity. A schematic of a typical combined cycle power plant is shown in Figure A-3.

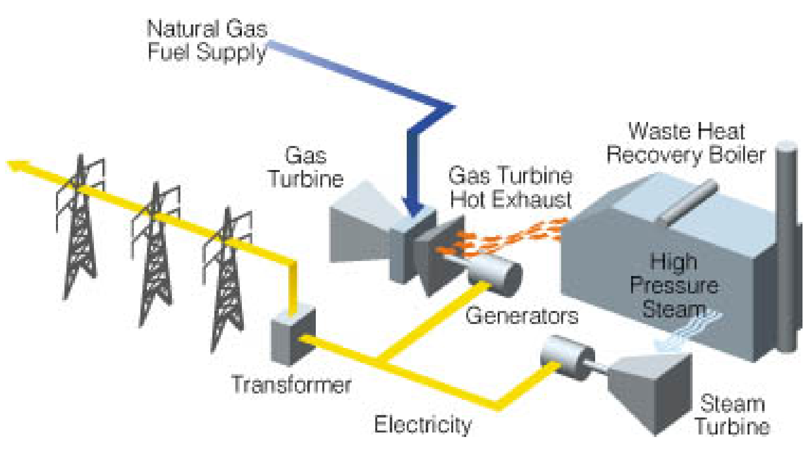


Figure A-3 Schematic of a Typical Combined Cycle Gas Power Plant (CASA, 2004)

Water Use

At most combined cycle plants, condensing exhaust steam from steam turbines is the largest use of water at the plant. For plants with wet cooling systems, the cooling tower make-up represents approximately 95% of the total power plant water requirements (Maulbetsch and DiFilippo, 2006). A number of alternative cooling systems exist and have been used (Maulbetsch and

DiFilippo, 2006). A discussion and comparison of these cooling systems is provided in Appendix C.

Similar to simple cycle plants, some water may be consumed for turbine inlet air cooling and by scrubbers for air emissions (e.g. NOx, SOx control) to meet air quality requirements (Maulbetsch and DiFilippo, 2006). Water consumption for combined cycle plants also consists of cooling system make-up water, auxiliary cooling, turbine inlet cooling, HRSG make-up water, environmental controls (such as NOx) and general plant water use (e.g. sanitary and cleaning) (Maulbetsch and DiFilippo, 2006).

In general, combined-cycle plants consume less water than a conventional coal plant because the steam cycle in an IGCC plant accounts for less than 40% of the plant's generated power. Since there is lower reliance on the steam cycle for power generation, boiler feedwater and blowdown from cooling water is also less.

Natural Gas – Co-generation Power Plants

Description

Co-generation is the simultaneous production of power and thermal energy. Such systems have potential in industry, where a significant requirement for electricity is coupled with a large demand for process heat or steam.

Some of the basic features of cogeneration power plants are listed below:

- Overall efficiency of converting fuel to electricity and heat can be greater than 80%;
- The steam portion of combined cycle plants takes time to heat;
- Cogeneration facilities are generally operated in a manner that serves the heat host, rather than focusing on electricity demand. These facilities must operate base loaded to achieve efficiencies and operational changes impact the industrial process that they are connected to.

Figure A-4 illustrates a gas co-generation plant where, in addition to the gas turbine electricity generation, the hot exhaust from the gas turbine is utilized to produce heat or steam for the on-site industrial process

.

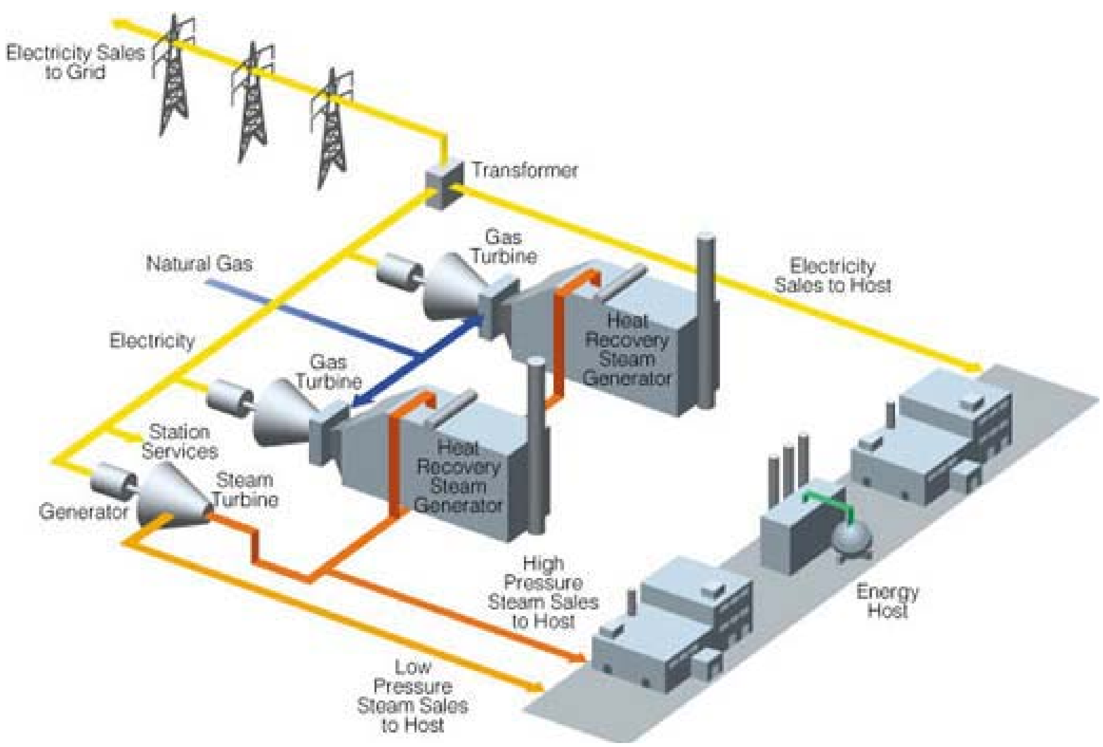


Figure A-4: Schematic of a Typical Co-generation Power Plant with Energy Host (CASA, 2004)

Water Use

Water use and consumption rates in co-generation plants can be similar to those in combined cycle power plants, but can also vary considerably depending on the amount of process steam used in the host facility's industrial processes.

Similar to simple cycle plants, some water may be consumed for turbine inlet air cooling and by scrubbers for air emissions (e.g. NOx, SOx control) to meet air quality requirements (Maulbetsch and DiFilippo, 2006).

Hydropower Facilities

Description

There are two basic types of hydropower facilities in Alberta: conventional hydropower dams with reservoir capacity to manage the seasonal distribution of energy generation; and run-of-river facilities with little or no reservoir capacity. As of 2011, the majority (over 95%) of hydropower generation capacity in Alberta was produced from conventional hydropower facilities. A schematic of a typical hydropower facility is shown in Figure A-5a. A schematic of a run-of-river hydroelectric facility is shown in Figure A-5b.

Conventional hydropower uses the potential energy (pressure) of water to drive turbines and a generator, based on the flow rate and relative head or height of the water above the turbines.

Hydropower is often closely linked with other socio-economic benefits, including: flood control, drought management, water supply, and recreational uses. Flood control benefits are derived from temporarily storing water in the reservoir, resulting in a reduced flood peak further downstream. Similarly, larger reservoirs are able to bridge periods of drought by drawing on storage. The storage also provides opportunities for communities and industry to utilize reservoirs for water supply as well as recreation. Many conventional hydropower facilities are able to vary the water level in the upstream reservoir to manage seasonal water availability.

As a renewable energy source, hydropower energy has a relatively low output of greenhouse gases and no direct consumption of water. Water is typically diverted temporarily through a penstock (i.e. pipe to the turbines) where it is directed through turbines to produce electricity and then returned to the environment downstream of the power house. There may be additional releases of water from the reservoir during floods or to maintain downstream flow during dry conditions.

Water Use

Water is not consumed within the hydropower plant, because almost all the water that is diverted is returned to the environment. Some water, however, is lost at conventional hydropower facilities due to evaporation from the reservoir. In Alberta, lakes and reservoirs typically have a net evaporation – meaning that the amount of evaporation from the water surface is greater than the precipitation gain. The net evaporation is highly dependent on climate variability and location. Run-of river hydro facilities typically do not have large reservoirs or storage so there is little or no net evaporation loss from those systems.

Water consumption for hydropower in this CEP plan was estimated by calculating the net evaporation loss from hydropower reservoirs. The estimates focused on reservoirs that are primarily used for hydropower. These include the reservoirs in the Bow River System, the Brazeau dam, and the Bighorn dam on the North Saskatchewan River. Other dams in Alberta that produce hydropower were excluded if the primary purpose is not hydropower. For example, some reservoirs in southern Alberta were constructed primarily for irrigation water supply but also produce some hydropower opportunistically – such as the Milk River Ridge Reservoir near Lethbridge.

Overall, the hydropower reservoirs have about 100 mm to 200 mm per year net evaporation and a cumulative net evaporation volume of about 30 million m^3 per year on an average annual basis. The net evaporation was estimated for each reservoir based on precipitation records from the nearest climate stations (Environment Canada Climate Normals), mean annual lake evaporation estimates from Hydro-Climate modeling of Alberta South Saskatchewan Regional Planning Area (Golder, 2010), and lake areas reported by TransAlta. The net evaporation estimates may be conservatively high, because most of the reservoirs are located in remote high elevation locations where lake evaporation may be significantly less than the nearest climate stations with long-term records.

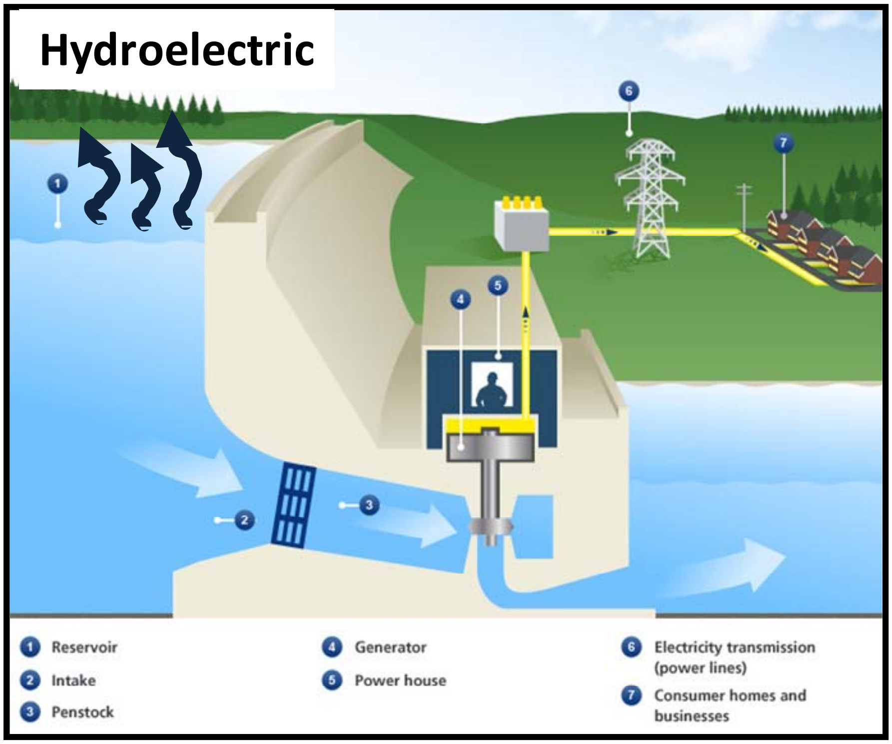


Figure A-5a: Conventional Hydroelectric Power Plant (EDF, 2012)

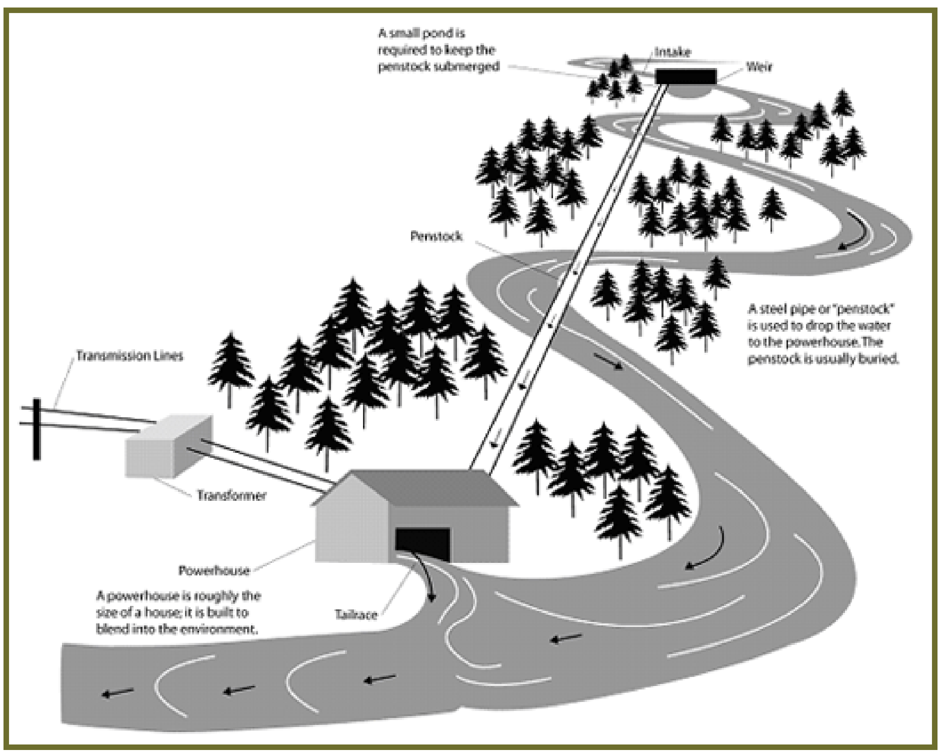


Figure A-5b: Run-of-River Hydro Facility (Veresen, 2012)

Biomass Power Plants

Description

Biomass can be wood, wood waste, peat or plant material that contain energy and can be burned to create heat or electricity. Biomass is still used widely around the world in developing and developed countries alike (IEA, 2007).

Biomass-fuelled power plants are similar in design to conventional coal-fired power plants; however, instead of coal being the fuel, a biomass fuel is used as the energy source.

Biomass is defined as either raw or secondary. Raw biomass consists of mainly trees and shrubs from forests, or crops such as grasses and low cost grains (NSP, 2012). Raw biomass is obtained from energy crops that are grown specifically to provide biofuels. Secondary biomass is any material that was derived from raw biomass, but has undergone significant chemical or physical changes (NSP, 2012). The forestry, pulp and paper, agricultural and food processing industries are the main sources of secondary biomass in Canada (NSP, 2012).

Basic features of a biomass plant are listed below (adapted from IEA, 2007):

- Due to feedstock availability issues, efficiencies of 20 to 35% are typical, which is lower than conventional coal-fired plants; and
- Biomass-fuelled plants are typically relatively small in size (under 100 MW).

Biomass-fuelled plants are similar in design to conventional coal power plants (Figure A-6).

Water Use

Condensing exhaust steam from steam turbines is the largest use of water at biomass plants (IEA, 2007).

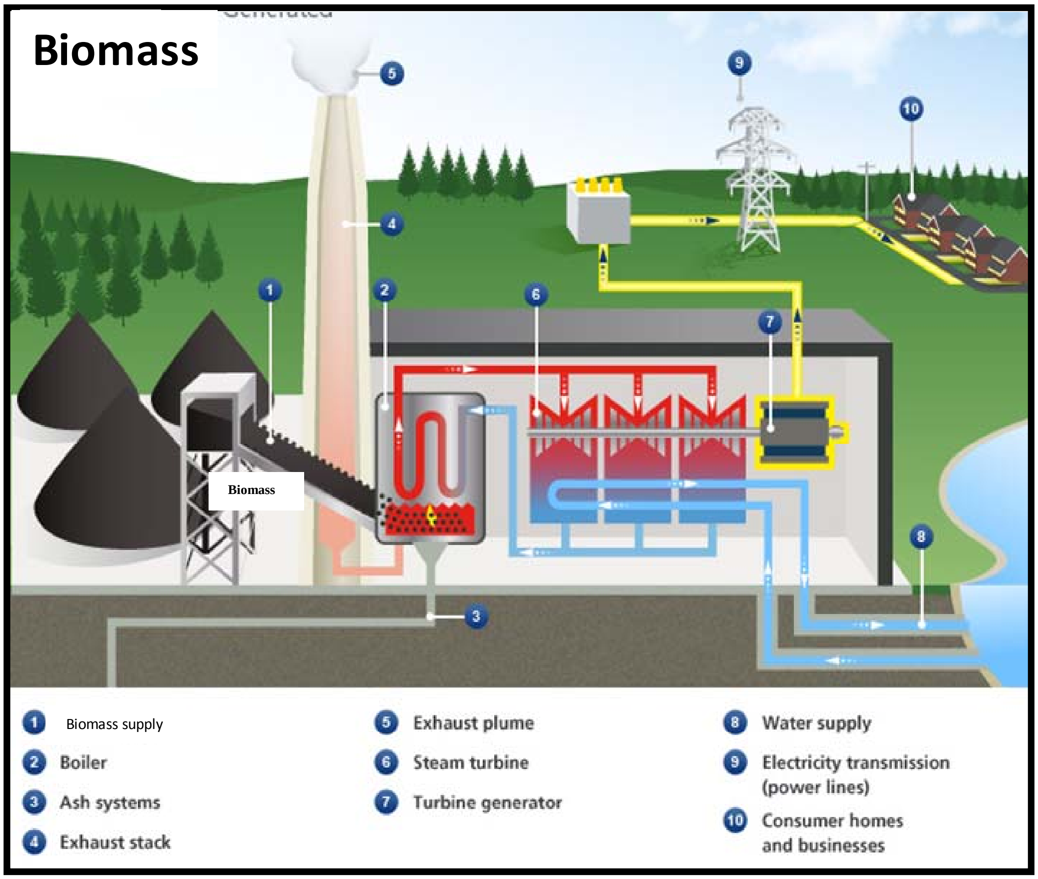


Figure A-6: Schematic of a Typical Biomass Power Plant (EDF, 2012)

Wind Turbines

Description

The output of modern wind turbines varies greatly depending on wind conditions. Wind generation is therefore located in areas that are consistently windy. Even small differences in wind speed can have a large impact on the performance a project (CANWEA, 2012).

Turbines are built to adapt to all kinds of wind conditions. Wind turbine blades can begin to turn at relatively low wind speeds (e.g. 13 km/h) and are usually shut off when the wind speeds become too high (i.e. greater than 90 km). In terms of power production, a wind turbine is designed and expected to generate about 30% of the time (CANWEA, 2012).

A diagram showing how wind turbines work is shown below (Figure A-7).

Water Use

Wind turbines do not consume water.

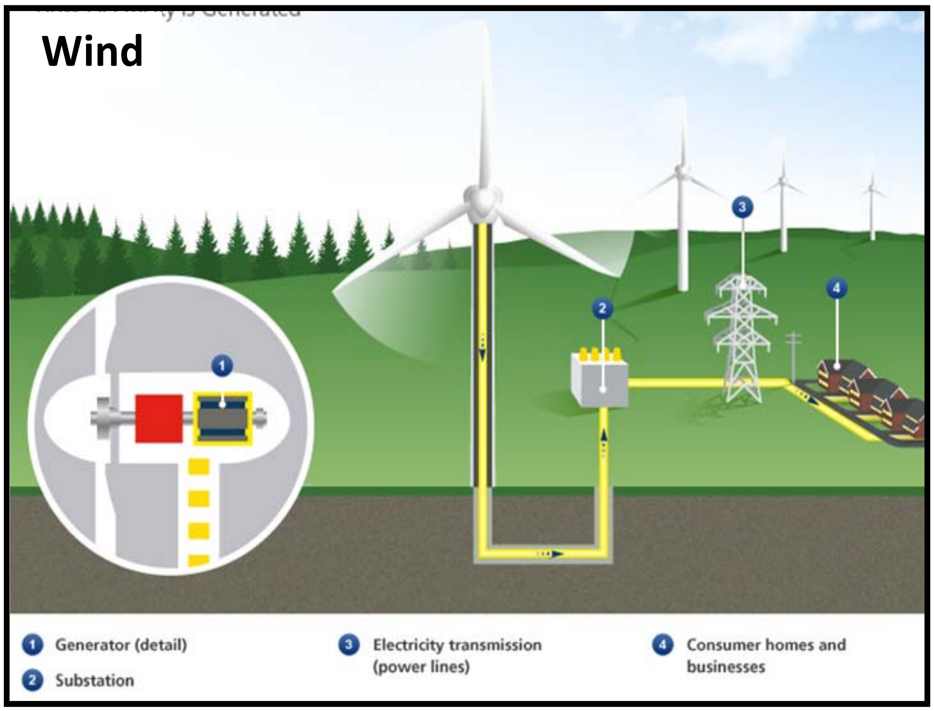


Figure A-7: Schematic of a Typical Wind Generation Turbine (EDF, 2012d)

Nuclear Power Plants

Description

Nuclear power generation uses energy contained in atoms. This energy is released as heat from chain reactions of radioactive elements such as uranium. In Canada nuclear power plants use CANDU reactors which are pressurized heavy water reactors that use natural uranium as fuel and heavy water as a coolant (CNSC, 2012).

The process begins in a reactor vessel which contains fuel rods comprised of sealed metal cylinders containing uranium oxide (EDF, 2012). Within these reactor vessels the uranium decays in a chain reaction that produces heat (EDF, 2012). Coolant (in the case of CANDU reactors, this is heavy water) flows through tubes in the reactor vessel absorbing the intense heat energy. Due to the high amount of thermal energy released, it is necessary for the reactor coolant water to stay in liquid form. The reactor coolant water is pressurized and sent to the steam generator. Here, the coolant water flows through a large heat exchanger in a closed loop before circulating back to the reactor vessel (EDF, 2012). A separate stream of water flows through the steam generator, around the outside of the reactor coolant water pipes. This water is under much less pressure, so the heat from the reactor coolant water pipes boils it into steam (EDF, 2012). The steam then passes through a steam turbine causing it to spin a shaft connected to a generator to produce electrical energy.

A schematic of a nuclear power plant is shown in Figure A-8.

Water Use

Cooling water for condensing steam is the largest use of water at a nuclear power plant (similar to conventional coal-fired power plants). The amount of water that is diverted for nuclear plants is generally higher than for coal-fired power plants.

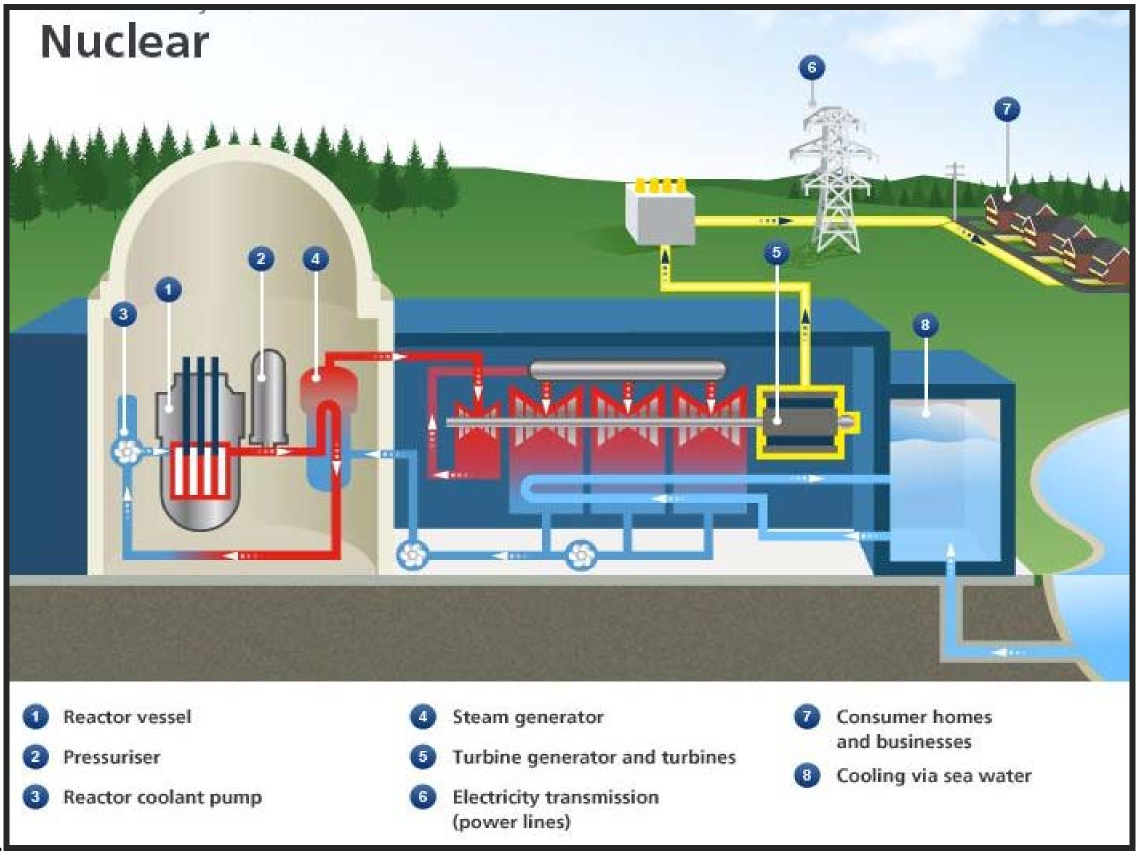


Figure A-8: Schematic of a Typical Nuclear Power Plant (EDF, 2012)

Resources

Archer, C. And Jacobson, M. 2007. *Supplying Baseload Power and Reducing Transmission Requirements by Interconnecting Wind Farms*. Journal of Applied Meteorology and Climatology 46: 170-1717.

Canadian Nuclear Safety Commission (CNSC). 2012.Nuclear Power Plants. Last Accessed May 30, 2012 at <http://nuclearsafety.gc.ca/eng/licenseesapplicants/powerplants/index.cfm>.

Canadian Wind Energy Association (CANWEA), 2012. Wind Energy: Wind Facts. Last Accessed May 30, 2012 at <http://www.canwea.ca/wind-energy/windfacts_e.php>.

CEATI International Inc (CEATI). 2011. Hydroelectric Industry's Role in Integrating Wind Energy. Montreal, QC CEATI No. T102700-0371.

Clean Air Strategic Alliance (CASA). 2004. *A Study on the Efficiency of Alberta's Electrical Supply System*. Project CASA-EEEC-02-04. Prepared by JEM Energy. Calgary, AB.

Crawley, J. n.d. *Technical Paper: Combined Cycle Systems for the Utility Industry*. Prepared for Universal Silencer Acoustic and Emission Technologies. Last accessed May 30, 2012 at <http://www.universalaet.com/docs/combined-cycle-systems-jbc.pdf>.

EDF Energy. 2012a. Coal Generation. Last Accessed May 30, 2012 at <http://www.edfenergy.com/energyfuture/coal-generation>.

EDF Energy. 2012b. Hydro Generation. Last Accessed May 30, 2012 at <http://www.edfenergy.com/energyfuture/ generation-hydro>.

EDF Energy. 2012c. Nuclear Generation. Last Accessed May 30, 2012 at <http://www.edfenergy.com/energyfuture/ generation-nuclear>.

EDF Energy. 2012d. Wind Generation. Last Accessed May 30, 2012 at <http://www.edfenergy.com/energyfuture/ generation-wind>.

Energy Technology Innovation Policy Research Group (ETIPRG). 2010. *Water Consumption of Energy Resource Extraction, Processing, and Conversion, A review of the literature for estimates of water intensity of energy-resource extraction, processing to fuels, and conversion to electricity*. Energy Technology Innovation Policy Discussion Paper No. 2010-15, Belfer Center for Science and International Affairs, Harvard Kennedy School, Harvard University

International Energy Agency (IEA). 2007. *IEA Energy Technology Essentials: Biomass for Power Generation and CHP*. Last Accessed on May 30, 2012 at <http://www.iea.org/techno/essentials3.pdf >.

Maulbetsch, J. S., and M. N. DiFilippo. 2006. *Cost and Value of Water Use at Combined-Cycle Power Plants.* California Energy Commission, PIER Energy-Related Environmental Research. CEC-500-2006-034.

National Energy Board (NEB). 2008. Coal-Fired Power Generation – An Overview-Energy Brief. Last Accessed on May 30, 2012 at

<http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/lctrcty/clfrdpwrgnrtn2008/clfrdpwrgnrtnnrgybrf-eng.html>.

National Energy Technology Laboratory (NETL). 2002. An environmental assessment of IGCC power systems. Presented at the 19th Annual Pittsburgh Coal Conference, September 23-27, 2002.

Nova Scotia Power (NSP). 2012. Renewable Energy: Biomass. Last Accessed May 30, 2012 at <http://www.nspower.ca/en/home/environment/renewableenergy/biomass/default.aspx>.

San Juan Valley Unified Air Pollution Control District. 2010. Final Staff Report and Recommendations on Agricultural Burning: Chapter 7- Biomass Power Plants. Last accessed May 31, 2012 at < http://www.valleyair.org/burnprograms/AgBurnRpts/9-VII-Biomass.pdf>.

Worldwatch Institute (January 2012) *Use and Capacity of Global Hydropower*. Energy Technology Innovation Policy Research Group (ETIPRG). 2010. *Water Consumption of Energy Resource Extraction, Processing, and Conversion, A review of the literature for estimates of water intensity of energy-resource extraction, processing to fuels, and conversion to electricity*. Energy Technology Innovation Policy Discussion Paper No. 2010- 15, Belfer Center for Science and International Affairs, Harvard Kennedy School, Harvard University

Veresen Inc. 2012. Renewable Power – Run-of-River. Last Accessed June 8, 2012 at <http://www.vereseninc.com/our-businesses/power/run-of-river.html>

Appendix B

Description of Cooling Technologies

Adapted from *"Water Consumption of Energy, Resource Extraction, Processing, and Conversion"* by Energy Technology Innovation Policy Research Group. Chapter 5: Electricity Conversion pp. 29 -32.

Cooling Technologies

The vast majority of water consumption in thermoelectric power generation relates to cooling. Thermoelectric power plants are those that use heat to produce steam which is then used to produce electricity (conventional coal, gas-fired combined cycle and nuclear are all examples of thermoelectric power plants). There are four basic cooling technologies (Figure B-1) for thermoelectric plants, with a few variations on the theme (Figures B-2 to B-5):

(i) Once-through;

(ii) Closed-loop or wet cooling;

(iii) Dry cooling; and

(iv) Hybrid cooling (incorporating elements of closed-loop and dry cooling).

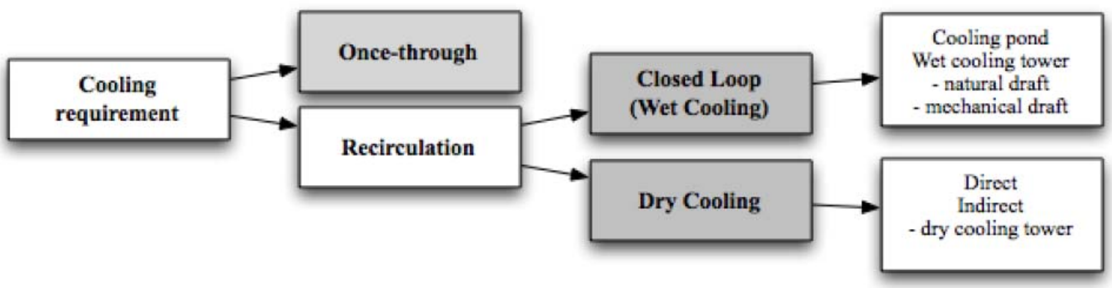


Figure B-1: Cooling options for thermoelectric power plants (Gerdes and Nichols 2009)

Once-Through (OT) Cooling

Once-through cooling was the conventional technology up until the early 1970s. Water is run through a condenser system inside the power plant, and used to condense the steam from the steam turbine. The water is then returned to the original source (e.g. a river, lake or ocean) about 20^{o}F warmer. The advantages of this technology are twofold: the relatively low capital and operating cost; and low net water consumption. The disadvantages are environmental due to the impact on aquatic life at the water intake and due to thermal discharge in the receiving environment. Another disadvantage is that although net consumption is low, the high throughput volumes required for the plant to operate could be a constraint in drought conditions (Electric Power Research Institute 2007, 26).

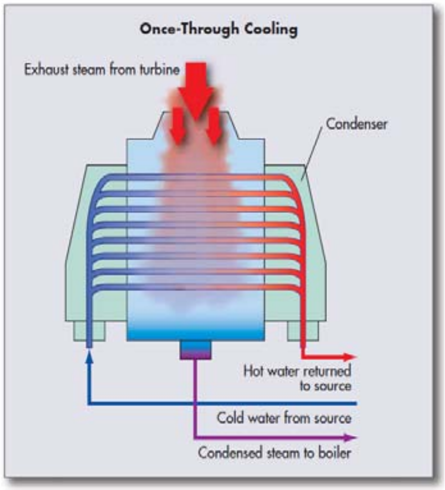


Figure B-2: Once-through Cooling Schematic (EPRI, 2007)

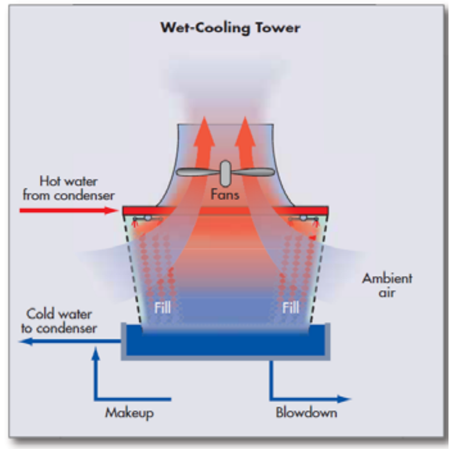


Figure B-3: Closed-loop (wet) cooling (EPRI, 2007)

Closed-Loop (CL) Cooling (Wet Cooling)

Closed-loop cooling has become the technology of choice for most power stations since the early 1970s, and is the most common method of cooling currently in Alberta. Closed-loop cooling systems use either wet cooling towers or a cooling pond as the source of re-circulating water. Cooling water is drawn from the cooling tower or cooling pond into the condenser in the power plant, and is then returned to the cooling tower or cooling pond. Relative to a once-through configuration, closed-loop cooling has relatively low water withdrawal from the makeup water source, but water consumption at the power plant is significantly higher because of losses to evaporation. Makeup water is drawn from a natural source (typically a river or lake) to replace the water returned to the environment through evaporation.

Dry Cooling (Air Cooling)

Dry cooling systems are similar to wet closed-loop; but the evaporative cooling tower is replaced with dry cooling towers cooled only by air, effectively eliminating water consumption. One significant downside of dry cooling is a negative impact on plant efficiency, as ambient temperatures and humidity affect the effectiveness of dry cooling and there is a significant parasitic load to power the cooling tower. The net result is that plant efficiency is higher for plants using wet cooling than for plants using dry cooling, especially in a hot, arid climate. The average loss of output is approximately 2% on an annual basis. But, at the peak of summer when demand is at its highest, the efficiency penalty can be as high as 25% (U.S. Department of Energy 2006).

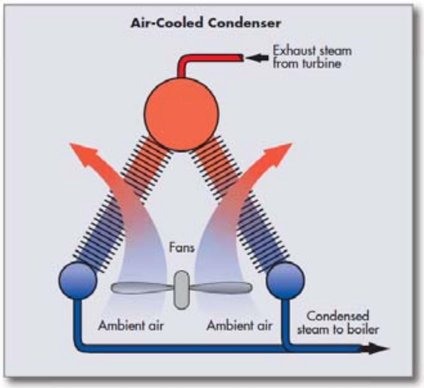


Figure B-4: Dry Cooling Schematic (EPRI, 2007)

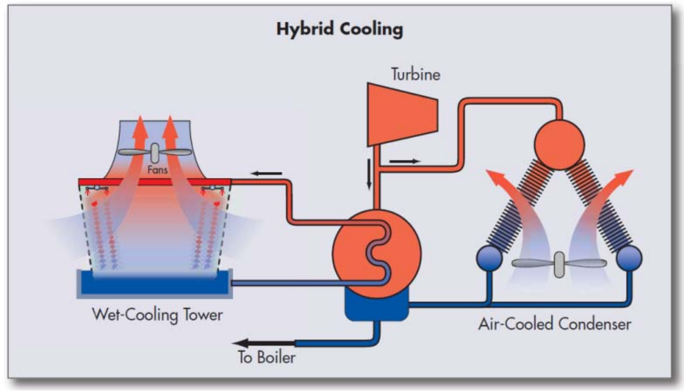


Figure B-4: Hybrid Cooling Schematic (EPRI, 2007)

In terms of choosing a cooling technology for a power plant, there are several factors to consider. In addition to water consumption and availability, other factors include capital costs, plant efficiency, efficiency variability, operational integrity, and power consumption. Some of the most important factors are summarized in the following table.

Hybrid Cooling (Adapted from EPRI, 2007)

A hybrid system can be used, for example, to substantially reduce the make-up water consumed without incurring the large increases in heat rate (and thus decreasing generating capacity) associated with all-dry systems. This is essentially achieved by taking a dry system and combining it with just enough wet-cooling capacity to prevent significant deterioration in power plant efficiency during the hottest days of the years. Sometimes these systems are referred to as dry/wet peaking cooling tower systems. When temperatures rise, the wet-cooling system is turned on, improving heat rates and generation capacity. Hybrids can reduce the water that would be required by wet systems by as much as 80%.

Cooling Cost and Performance Comparison

Table B-1 shows industry estimates for the capital cost of different cooling technologies on a unit of capacity basis. Dry cooling is nearly ten times more expensive than one-through (Electric Power Research Institute 2007, 26).

Table B-1: Capital Cost of Cooling Technologies

	$/kW	*Relative to once-through*
Once-through	19	-
Closed-loop/cooling pond	28	+47%
Others including dry cooling	182	+858%

Figure B-5 takes the same analysis a step further by incorporating other costs into the power plant. The overall increase in the cost of the power plant (an illustrative 500 MW steam power plant) increases by nearly 13% by going from once-through to dry-cooling. The increase from once-through to closed-loop (wet) is small, at less than 1%.

Table B-2 outlines the advantages and disadvantages of various cooling technologies.

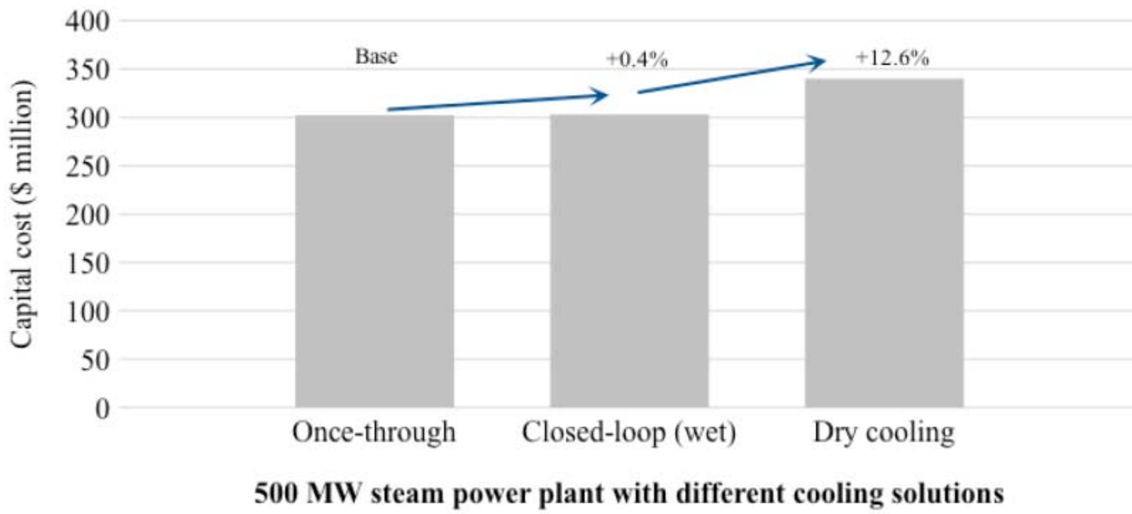


Figure B-5: Illustrative Impact on Capital Cost for a Hypothetical 500 MW Steam Power Plant of Different Cooling Technologies

Resources

Electric Power Research Institute. 2007. “EPRI Journal, Summer 2007”. Palo Alto, California.

Gerdes, K. and Nichols, C. 2009. Water requirements for existing and emerging thermoelectric plant technologies.” National Renewable Energy Laboratory, U.S Department of Energy. Boulder, Colorado.

O’Hagan, J. and Maulbetsch, J. 2009. “*Water use for electricity generation*”. California Energy Commission – Public Interest Energy Research (PIER), accessed May 29, 2011 at http://www.energy.ca.gov/2009_energypolicy/documents/2009-08-10_workshop/presentations/04_CEC_OHagan_Advanced_Generation.pdf

U.S. Department of Energy. 2006. “Energy demand on water resources - report to Congress on the interdependency of energy and water”. Washington, D.C.

Appendix C

CEP Presentation

Water Conservation, Efficiency and Productivity (CEP) Plan:
Power Generation Sector

June 14, 2012

Power Generation Sector

Background Information

- Deregulated Wholesale Electricity Market electricity market reflects demand and supply in real time
- Capital intensive industry; Generators bear the risk of investment
- Alberta's needs for electricity have grown 84% over the last 20 years; Continued growth expected
- About 30 players with a total installed capacity of ~14,000 MW serving a peak demand of ~10,000 MW

Year	Energy Output (% of Total MWh)				
	Coal	Gas	Hydro	Wind	Other
2000	79	17	3	0	1
2011	72	20	4	4	1

Key Messages

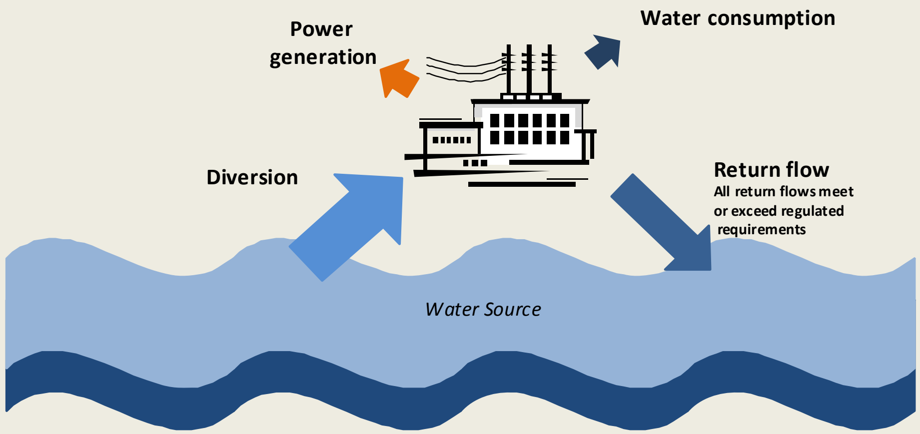
Significant Improvements Already Achieved

- Generation technology improvements have increased process efficiency and reduced water consumption
- Current transition from existing fossil-fuelled thermal facilities (e.g. coal) to combined-cycle, cogeneration and renewable reduces water consumption
- Water consumption is currently expected to stay about the same until 2030, despite a forecast doubling of electricity demand

Challenges

- Legislation to achieve one environmental objective may harm another objective i.e. air emission controls may increase water consumption
- Electric power generation sector will require water for the foreseeable future

Application of Water Terminology to the Power Sector



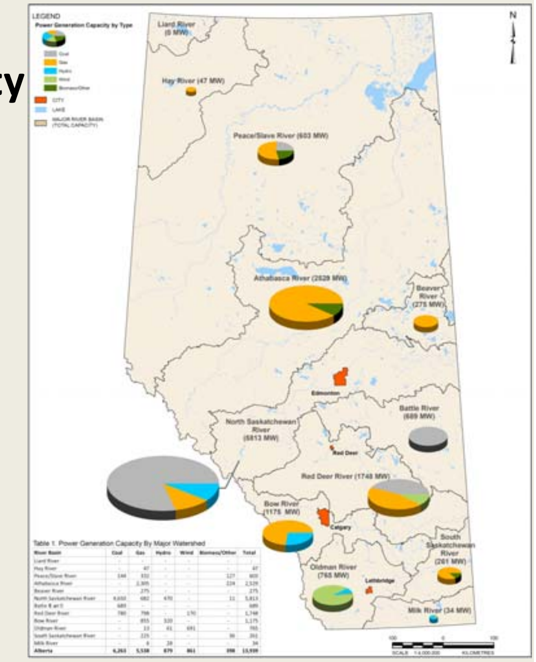
Power Generation Water CEP Plan Scope

- Includes water consumption for Alberta generation only
  (not including water requirements for power imports)
- Includes power generation from:
  - Fossil-fueled thermal (e.g. coal)
  - Combined-cycle, simple-cycle, co-generation (e.g. Gas)
  - Biomass
  - Renewables (e.g. hydroelectric, wind, solar)
- Excludes water diverted for:
  - Concurrent uses (i.e. steam production from co-generation)
  - Resource extraction and delivery

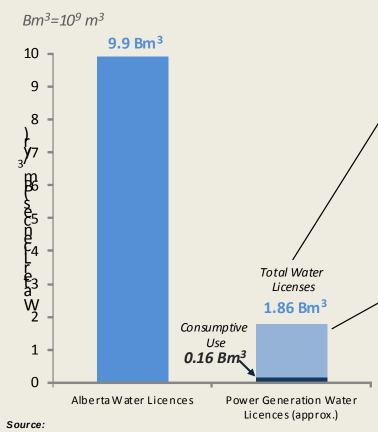
Existing Power Generation Capacity by Watershed

- Disk Locations = Specific Watershed
- Disk Size = Relative Magnitude of Installed Generation Capacity
- Disk Colours = Different Generation Types

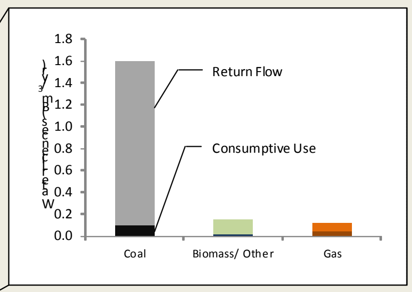
Sources:
•AESO List of Generators, 2011



Alberta Power Generation Water Licenses



Source:
Government of Alberta, 2009
Water Use and Water License Information



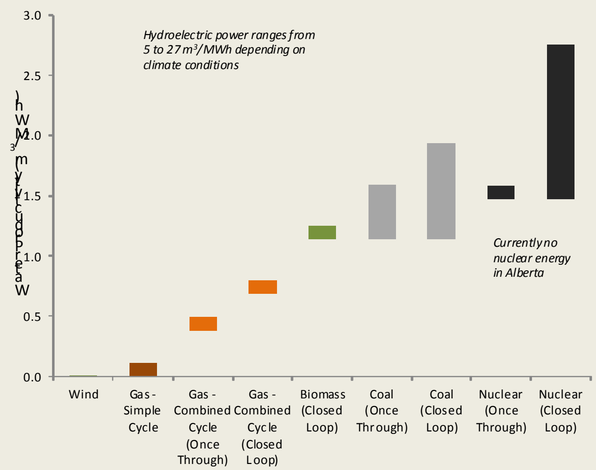
	Coal (Bm^3/yr)	Biomass/ Other [1] (Bm^3/yr)	Gas [2] (Bm^3/yr)	Total (Bm^3/yr)
Licensed Consumption	0.10	0.02	0.04	0.16
Return Flow	1.49	0.13	0.08	1.70
Total Licensed Diversion	1.59	0.15	0.12	1.86

1. Biomass/Other power generation includes only licenses associated with AESO units. Includes other industrial purposes other than electricity generation.
2. Gas generation includes only licenses associated with AESO units that are described as "other/cooling". This may include some water used for other purposes and not solely power production.

Typical Water Consumption by Generation Type

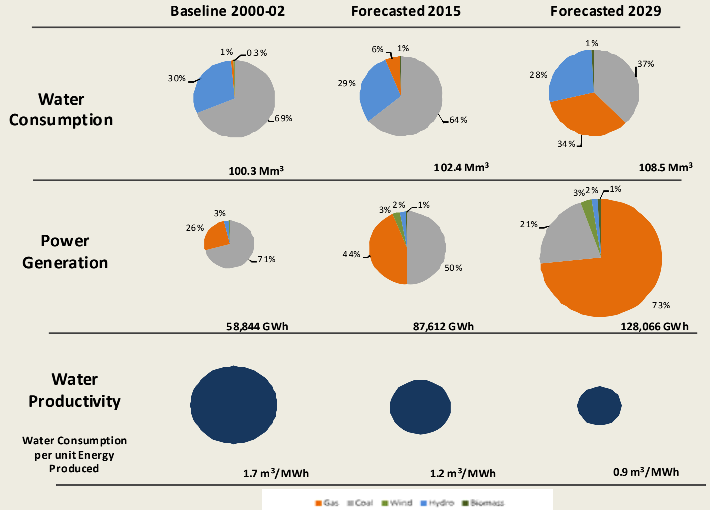
For the power sector:
Water productivity = water consumption (m^3) divided by power generation (MWh)

Consumptive use includes:
- Cooling (e.g. evaporative loss)
- Boiler (e.g. water treatment)
- Plant Facility (e.g. washing, domestic use)



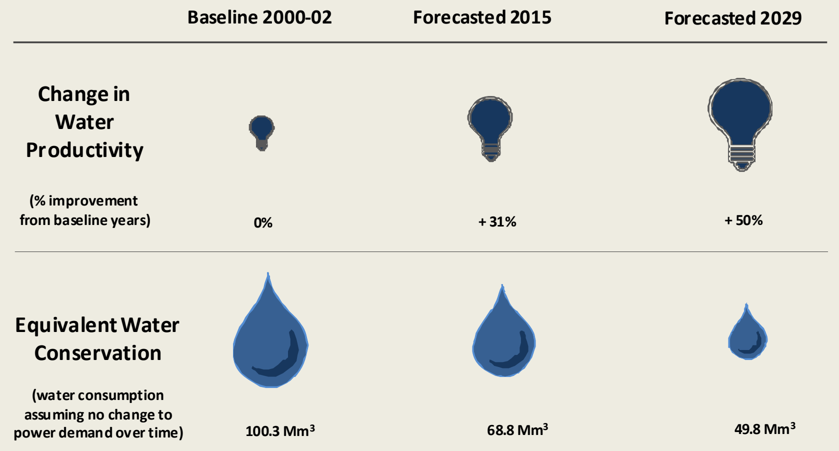
Source: Energy Technology Innovation Policy Research Group (2010)

Generation Mix v. Water Consumption



Sources:
- *Alberta Environment & Sustainable Resource Development Water Diversion and Return Flows (2005 to 2011) for coal*
- *AESO Annual Net Generation Data (2000 to 2011 power generation) and AESO Long-term Transmission Plan (2011) for forecasted information (2012 to 2029)*
- *Typical consumption rates from Energy Technology Innovation Policy Research Group (2010)*

Water Productivity and Conservation



CEP Power Sector Past Successes

- Application of new technology and equipment increases efficiency, reduces energy consumption and water use
- Water treatment improvements reduce chemical and water usage
- Use of low water use air-emission control equipment, when technology is appropriate
- Use of cooling ponds to reduce the volume of diverted water
- Co-benefits of generation facilities include provincial parks, local habitat improvement opportunities, infrastructure sharing (e.g. community water source management, irrigation)

CEP Opportunities

Opportunity	*Benefits*
1. Consider generation technologies with lower water consumption: • Aging facilities to retire over next 20 years - expected replacement with lower water intensity technology	Productivity
2. Continue to evaluate process improvements at individual facilities: • Water treatment improvements and reuse	Efficiency
3. Upgrades to transmission infrastructure reduce electricity transmission losses, increase distributed site opportunities	Conservation
4. Improved availability and completeness of water diversion, consumption and return flow information submitted to AESRD from all sources	CEP
5. Continued development of meaningful Demand Management opportunities to reduce energy consumption	Consumers
6. Consumers expected to choose improved energy efficiency options (e.g. energy conservation, usage patterns)	Consumers

CEP Challenges

Electric power generation sector is influenced from outside…

- Magnitude, location and timing of electricity demand
  - Affect power generation options and choices
- Commodity prices and market dynamics (e.g. gas price, location)
  - Influence the future generation mix and operations with a corresponding effect on water consumption
- Regulations in one regulatory area impact other regulatory priorities
  - Regulations to reduce air emissions and GHG may result in increased water consumption

CEP Implementation

- Continue to consider water efficiency measures for individual facilities
- Developed metrics that can be used to estimate sector water consumption - utilize the measures as the primary metrics for future tracking of sector CEP progress
- Improve availability and completeness of water diversion, consumption and return flow information submitted to AESRD from all sources to improve estimates of actual water consumption and use
- Promote balanced assessment between conflicting air, water and land environmental objectives – by evaluating tradeoffs as part of the planning process for new power generation

Summary

- Significant water productivity improvements have been achieved to date
- Current transition from existing fossil-fuelled thermal facilities (e.g. coal) to combined-cycle, cogeneration and renewable reduces water use intensity
- CEP Plan shows:
  - 31% water productivity improvement by 2015; 50% by 2029
  - Water consumption is currently expected to stay about the same until 2030, despite a forecast doubling of electricity demand
    - 2% increase in total water consumption by 2015, 8% by 2029
- Developed metrics to estimate sector's future water consumption
- Challenges:
  - Legislation to achieve one environmental objective may impact another objective i.e. air emission controls may increase water consumption
  - Electric power generation sector will require water for the foreseeable future

Alberta's Water for Life Strategy:

Electricity Generation Sector Water Conservation, Efficiency and Productivity (CEP) Review

Comparison to Criteria for Review

✓ Results in continuous CEP improvements	✓ Identifies opportunities that will lead to improvements in conservation, efficiency, and productivity
✓ Identifies benchmarks and measurable CEP targets for water productivity	✓ Identifies a metric and a current benchmark
✓ Review and analysis of potential CEP opportunities and selection of those which will achieve CEP improvements	✓ Current implemented opportunities identified in addition to potential opportunities relating to conservation, efficiency and productivity
✓ Outlines process to involve stakeholders and address stakeholder interests	✓ Focus on collection of information to enable additional discussion with interested parties
✓ Describes how sector CEP activities will be monitored and evaluated to measure CEP improvements	✓ Developed indicative metrics can be used as required, until sufficient actual data and information is available to update methodology
✓ Describes the sector's process for ongoing reporting objectives and performance measures for the sector.	✓ Use reporting programs in place to update and communicate progress
✓ Outlines an implementation schedule	✓ Implementation is on-going with operational and development plans, benchmarks and metrics updated as required
✓ Follows the recommended annotated Table of Contents	✓ Plan generally follows annotated Table of Contents